BC HYDRO 2021 INTEGRATED RESOURCE PLAN EXHIBIT B-28

**Chris Sandve**
Chief Regulatory Officer
Phone: 604-623-3726
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

March 9, 2023

Sara Hardgrave
Acting Commission Secretary and Manager
Regulatory Services
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Sara Hardgrave:

**RE: Project No. 1599287**
**British Columbia Utilities Commission (BCUC or Commission)**
**British Columbia Hydro and Power Authority (BC Hydro)**
**2021 Integrated Resource Plan (2021 IRP)**
**Evidence**

BC Hydro writes to file, as evidence in this proceeding, an independent expert report by Dr. Kathleen Spees, Ph. D., entitled “Benchmark Assessment of BC Hydro’s System and Locational Supply Adequacy Standards”. BC Hydro asked Dr. Spees to provide an independent assessment of BC Hydro’s system-wide and locational supply adequacy planning standards in consideration of the evidence submitted by RCIA, Capital Power and CEBC.

For further information, please contact Shiau-Ching Chou at 604-623-3699 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

df/rh

Enclosure

BEFORE THE

# British Columbia Utilities Commission

**BC Hydro**

**2021 Integrated Resource Plan**

APPLICATION # 1599287

**Written Evidence of Dr. Kathleen Spees**

# Benchmark Assessment of BC Hydro's System and Locational Supply Adequacy Standards

EVIDENCE SUBMITTED AT THE REQUEST OF

**BC Hydro**

MARCH 9, 2023

CONTENTS

Introduction .......................................................................................................................... 3

I. Executive Summary ....................................................................................................... 4

II. BC Hydro Has Adopted Both a Probabilistic System-Wide Resource Adequacy Standard and a Deterministic Locational Reliability Standard ............................................................ 8

III. British Columbia’s Reliability Standards Are in Alignment with Standard Industry Practice ........................................................................................................................ 10

IV. BC Hydro’s Proposed Supply Plan in Vancouver Island Meets the Approved Locational Planning Standards, Even without Island Generation Facility ........................................... 18

V. Findings in Consideration of Interveners’ Comments....................................................... 19

## Introduction

I, Dr. Kathleen Spees, was retained by BC Hydro to review and independently assess evidence related to supply adequacy standards in the context of BC Hydro's proposed *2021 Integrated Resource Plan* ("BC Hydro 2021 IRP").[1]

I was asked by BC Hydro to offer to the British Columbia Utilities Commission (BCUC or Commission) my independent assessment of BC Hydro's system-wide and locational supply adequacy planning standards in consideration of the following evidence submitted by interveners:

- Residential Consumer Intervener Association (RCIA), via its agent Midgard Consulting, submitted *Evidence for the Residential Consumer Intervener Association* ("RCIA/Midgard Evidence");[2]
- Capital Power Corporation (Capital Power) submitted both policy evidence ("Capital Power Policy Evidence") and expert evidence of Mr. Dragan Brankovich of PowerEN Corporation ("Brankovich Evidence");[3] and
- Clean Energy British Columbia (CEBC) has submitted evidence developed by Mr. Travis Lusney of Power Advisory ("CEBC/Lusney Evidence").[4]

Specifically, BC Hydro has asked me to provide a summary explanation of the current system-wide and locational supply adequacy standards; provide a benchmark comparison of BC Hydro's supply adequacy standards compared to those adopted in other regions; and assess the interveners' submitted evidence regarding their interpretation of the current standards or how the standards could be revised. My assessment of this evidence is qualitative in nature. I have not conducted an independent modeling analysis of potential reliability outcomes in BC Hydro's system and so do not offer an independent assessment of the accuracy of BC Hydro's reliability modeling nor of the interveners' alternative reliability modeling assessments.

---

1 BC Hydro. *BC Hydro 2021 Integrated Resource Plan Application*. December 21, 2021. ("BC Hydro 2021 IRP")

2 Midgard Consulting Incorporated. *Evidence For The Residential Consumer Intervener Association on BC Hydro 2021 Integrated Resource Plan*. Prepared for RCIA. January, 2023. ("RCIA/Midgard Evidence")

3 Capital Power Corporation. *Evidence of Capital Power Corporation*. January 19, 2023 ("Capital Power Policy Evidence"); Dragan Brankovich. *Evidence on Behalf Capital Power Corporation—BC Hydro 2021 Integrated Resource Plan*. Prepared for Capital Power Corporation. January, 2023. ("Brankovich Evidence")

4 Travis Lusney. *BC Hydro 2021 Integrated Resource Plan*. Filed on behalf of Clean Energy British Columbia (CEBC). January, 2023. ("CEBC/Lusney Evidence")

I am an economic consultant at The Brattle Group, where I focus on bulk electricity system reliability, electricity market design, and energy policy in the context of clean energy transition. I have conducted economic and modeling analysis of supply adequacy standards for utilities, policymakers, and market operators across more than a dozen jurisdictions across Canada, the US, and internationally.[5] I earned my PhD in Engineering and Public Policy and MS in Electrical and Computer Engineering from Carnegie Mellon University, and a BS in Mechanical Engineering and Physics from Iowa State University. My curriculum vitae is included as an attachment.

I confirm that I have a Duty of Independence in offering my professional opinion to the Commission. Accordingly, though I was retained by BC Hydro to conduct an independent assessment and present my resulting findings to the Commission, I am not an advocate for BC Hydro or any other party. All of the opinions set out in this submission are my own. I am solely responsible for the content of this submission and have prepared this submission in accordance with the Duty of Independence. If called to give oral or written testimony, I will offer that testimony in conformity with the Duty of Independence.

# I. Executive Summary

BC Hydro's proposed Integrated Resource Plan (IRP) offers a projection of consumer electricity demand and proposed mix of existing resources, new resources, and independent power producer (IPP) contracts to be considered to meet that demand, considering legal requirements and policy objectives.[6] The IRP considers environmental, economic, and social factors to prepare the electricity system to reliably support expected growth in electricity consumption across

---

5 As examples of my work related to assessments of resource adequacy standards, see:

Johannes P. Pfeifenberger, Kathleen Spees, Kevin Carden, Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications*. Prepared for the Federal Energy Regulatory Commission (FERC). September, 2013.

Samuel Newell, Kathleen Spees, Johannes P. Pfeifenberger, Robert Mudge, Michael DeLucia, Robert Carlton. *ERCOT Investment Incentives and Resource Adequacy*. Prepared for ERCOT. June, 2012.

Samuel Newell, Kathleen Spees, Johannes P. Pfeifenberger, Ioanna Karkatsouli, Nick Wintermantel, Kevin Carden. *Estimating the Economically Optimal Reserve Margin in* ERCOT. Prepared for the Public Utility Commission of Texas. January, 2014. See also the *2018 update*.

Toby Brown, Neil Lessem, Roger Lueken, Kathleen Spees, Cathy Wang. *High-Impact, Low-Probability Events and the Framework for Reliability in the National Electricity Market*. Prepared for The Australian Energy Market Commission. February, 2019.

Kathleen Spees, David Luke Oates, Cathy Wang, Matthew Witkin. *Alberta's Capacity Market Demand Curve*. Prepared for Alberta Electricity System Operator. January, 2019.

Staff of the New Jersey Board of Public Utilities (BPU), with Analytic Support from Kathleen Spees, Samuel Newell, Joseph DeLosa, et al. Alternative Resource Adequacy Structures for New Jersey. June, 2021.

6 BC Hydro 2021 IRP.

several scenarios (e.g., for accelerated electrification scenarios and greenhouse gas (GHG) emissions reduction targets).

The total quantity of resources needed to serve customers reliably is determined consistent with BC Hydro's supply adequacy and transmission planning standards, which dictate the technical measurement of what constitutes sufficiently reliable supply planning. The BC Hydro 2021 IRP is developed to meet two separate supply adequacy standards that have been approved or accepted by the BCUC:[7]

- **System-wide supply adequacy standard** that stipulates there must be enough supply resources to ensure supply shortage events will occur no more than one day in 10 years ("1-in-10"), measured as 1 day per 10 years with loss of load events or 0.1 days/year loss of load expectation (LOLE).
- **Locational transmission planning standards** applicable to Vancouver Island and other potentially transmission-constrained subregions, that stipulates there must be sufficient local supply resources or transmission capability to serve demand under normal conditions and under seven distinct contingency planning scenarios in which the largest generation and transmission resources may become unavailable at the same time.

## SUMMARY OF INTERVENERS' EVIDENCE REGARDING SUPPLY ADEQUACY STANDARDS

Three interveners submitted comments related to the application or interpretation of these standards. The **RCIA/Midgard Evidence** provides a discussion and analysis of BC Hydro's system-wide resource adequacy standard and other aspects of the BC Hydro 2021 IRP, with a focus on the potential cost implications for consumers. The RCIA/Midgard Evidence states that, based on survey it has conducted, "residential customers are content with current system reliability levels and are unwilling to pay more for improved reliability."[8] To reduce potential cost to residential consumers, the RCIA/Midgard Evidence recommends:[9]

---

7 British Columbia Utilities Commission (BCUC). *Order Number G-15-22.* In the matter of the Utilities Commission Act, RSBC 1996, Chapter 473 and BC Hydro 2021 IRP.

8 RCIA/Midgard Evidence. Page 42.

9 The RCIA/Midgard Evidence offers other recommendations that are outside the scope of this evidence, including to improve reliability modeling transparency and recommends revised use of load forecasts for use in capital investments and transmission planning.

- To consider the economic costs of supply adequacy standards including quantifying the risks, and then mitigating them by "transparently optimizing and prioritizing resources to ensure mitigation measures do not outweigh the risks they are intended to address."[10]
- "BC Hydro should reduce its 12% Planning Reserve Margin (Capacity Margin) to a lower percentage (in the range of 8.4% - 10%)" with the 8.4% value derived from the example of Midcontinent Independent System Operator (MISO);[11] and
- Reducing total supply adequacy needs by shifting what the RCIA/Midgard Evidence describes as a "generation centric" convention (measured as 12% of dependable capacity) to a "load centric" reserve margin convention (measured as 12% of peak consumer demand).[12]

The **Capital Power Policy Evidence** addresses supply adequacy on Vancouver Island, and asserts that Capital Power's generation asset Island Generation (a 275 MW natural gas-fired combined cycle plant) is needed to support reliability on Vancouver Island through 2030.[13] The Capital Power Policy Evidence relies on the **Brankovich Evidence**, which assesses reliability outcomes with and without Island Generation under a variety of scenarios, concluding that:[14]

- Reliability on Vancouver Island would be below a 2.4 loss of load hours (LOLH) reliability level under several scenarios examined over 2024-2030 (considering scenarios of transmission cable outage timing and alternative supply assumptions);[15]
- Maintaining Island Generation in an available status would improve reliability on Vancouver Island; and
- BC Hydro's deterministic locational supply adequacy standard and associated analysis should be revised to account for the random effect of forced outages.

The **CEBC/Lusney Evidence** and recommendations are focused primarily on topics outside the scope of my review, but also provides a summary of emerging supply-side and demand-side supply adequacy risks as identified by the Western Electricity Coordinating Council (WECC).[16] The CEBC/Lusney Evidence then recommends that these risks should be accounted for both in

---

10 RCIA/Midgard Evidence. Pages 6–8, 43–44.

11 RCIA/Midgard Evidence. Pages 43.

12 RCIA/Midgard Evidence. Pages 7, 30–33, 43–44.

13 Capital Power Policy Evidence. Pages 2, 11–12.

14 Brankovich Evidence. Pages 22–23.

15 Brankovich Evidence. Table 4 and Pages 22–23.

16 See CEBC/Lusney Evidence. Page 35.

conducting modeling of supply needs and in assessing the value of imports within Contingency Resource Plans.[17]

### FINDINGS REGARDING BC HYDRO'S SUPPLY ADEQUACY ASSESSMENT

In my assessment of the BC Hydro supply adequacy standards and related interveners' comments, I find that:

- Finding 1: BC Hydro's 2021 IRP is developed consistent with BCUC-approved system and locational supply adequacy standards.
- Finding 2: BC Hydro's system-wide and locational supply adequacy standards are in alignment with standard practice in other regions, though a robust cross-regional comparison requires careful treatment of differences in units of measure, accounting conventions, and underlying reliability drivers.
- Finding 3: On Vancouver Island, the supply plan proposed in the BC Hydro 2021 IRP is consistent with the current BCUC-mandated local supply adequacy standards, even without Island Generation. The Brankovich Evidence finds that supply is inadequate because it measures supply adequacy relative to a more stringent standard recommended by the intervener (but that has not been reviewed or approved by the BCUC).
- Finding 4: If the BCUC wishes to reconsider or otherwise update its current supply adequacy standards, I recommend to do so in full consideration of all relevant policy tradeoffs including those highlighted by interveners. In particular, such a review should weigh the advantages of accepting lower levels of reliability (primarily the advantage of reducing supply investment costs, as emphasized in the RCIA/Midgard Evidence) compared to the advantages of increased reliability (as emphasized in the Capital Power Policy Evidence and the CEBC/Lusney Evidence).

I expand on these findings in the body of this evidence and in response to specific intervener comments farther below.

[17] See CEBC/Lusney Evidence. Pages 10, 16–17.

# II. BC Hydro Has Adopted Both a Probabilistic System-Wide Resource Adequacy Standard and a Deterministic Locational Reliability Standard

Presently, the two standards relevant to ensure supply adequacy that have been approved or accepted by the BCUC are the 0.1 days/year LOLE system-wide standard, and the contingency-based mandatory locational transmission planning standards. For the former, the BCUC has accepted the use of the 0.1 LOLE standard, which BC Hydro has utilized since 1975. For the latter, as required under the Utilities Commission Act (UCA) Section 125.2, the BCUC may approve mandatory standards for ensuring reliability of the electricity system, if those standards are deemed in the public interest.[18] To that end, the BCUC has mandated the adoption of transmission planning standards developed by the non-jurisdictional standard-making bodies, the North American Electric Reliability Corporation (NERC) with monitoring assistance provided by the WECC.

## A. The 0.1 LOLE Probabilistic System-Wide Standard

BC Hydro uses a system-wide supply adequacy measure of one-day-in-10-years or 0.1 LOLP for system-wide shortfall events, a standard that it adopted in 1975.[19] The BCUC has more recently reviewed and approved use of the 0.1 LOLP standard in its review of the BC Hydro *2006 Integrated Electricity Plan and Long-Term Acquisition Plan,* when the BCUC stated that "The Commission Panel agrees with the overall evaluation of the capacity reserve margin using the one day in ten year LOL[E] methodology."[20] Since that time, the 0.1 LOLE system-wide standard has been used in BC Hydro's *2008 Long-Term Acquisition Plan*, *2013 Integrated Resource Plan*, and now in the proposed BC Hydro 2021 IRP.[21]

To translate the 0.1 LOLE standard to a quantity of supply resources that will be needed to maintain reliability, BC Hydro has conducted a probabilistic modeling assessment.[22] The modeling

---

18 Government of British Columbia. *Utilities Commission Act – Chapter 473*. Current to February 22, 2023.

19 BC Hydro 2021 IRP. Pages 5-19 through 5-21.

20 For clarity and consistency in use of acronyms throughout this evidence, I replace in this quotation the loss of load probability (LOLP) with loss of load expectation (LOLE). In both cases the measurement refers to 0.1 days/year event expectation (though, as I discuss further in the following section, "1-in-10" and related terms are often used interchangeably to refer to somewhat different metrics).

British Columbia Utility Commission (BCUC). *Decision on BC Hydro 2006 IRP.* *Page* 60.

BC Hydro. *Argument - 2006 Integrated Electricity Plan and Long-Term Acquisition*. *Page* 28.

21 BC Hydro. 2008 Long Term Acquisition Plan.

BC Hydro. *Meeting BC's Future Electricity Needs.* November 2013.

22 BC Hydro 2021 IRP. Pages 5-20 and 5-21.

assesses the estimated frequency of supply shortfall and potential load shedding events that could materialize due to some combination of generation outages, intermittent resource variability, dry or critical hydrological conditions, and high demand levels. The modeling evaluates the probability of insufficient supply to meet peak demand each day across the winter season when demand is highest. The average annual probability of outages over the simulated years corresponds to the system's LOLE.

From LOLE modeling, BC Hydro estimated it must maintain 12% dependable capacity reserves to ensure system resource adequacy. This dependable capacity reserve does not make use of non-firm imports or external market purchases from the US or Alberta.

## B. The Deterministic Locational Transmission Planning Standards

BC Hydro follows the transmission planning standards developed by the NERC, which have in turn been reviewed and approved by the BCUC consistent with the "Commission's general policy to have the British Columbia Mandatory Reliability Standards Program (BC MRS Program) align with the [NERC] MRS Program in the United States."[23] The BCUC has further engaged with the WECC to assist the BCUC in monitoring compliance with the approved standards.[24]

In BC Hydro's system, transmission planning standards are the determinant of locational resource adequacy needs. These standards dictate that all subregions of the bulk power system must maintain either sufficient transmission capability or enough local supply resources to protect against outages across a wide range of scenarios. BC Hydro performs power flow analysis of the transmission system under normal and contingency conditions to identify network reinforcements or new transmission additions that may be needed over the planning horizon. In some cases, the need for transmission upgrades can be avoided if sufficient local generation or demand-side resources are available in a particular subregion (and vice versa).

The pertinent standards as implemented to ensure locational resource adequacy in the BC Hydro system are the NERC TPL-001-4 (which defines the contingency analysis that must be conducted in Table 1) and the WECC criterion 16 TPL-001-WECC-CRT-3.2 (which provides additional guidance on how to conduct the power flow analysis).[25] This NERC standard defines seven distinct

---

23 British Columbia Utility Commission. *Order Number R-12-17*. In the matter of the Utilities Commission Act, RSBC 1996, Chapter 473 and reliability standards. February 2017.

24 Id. Page 1.

25 BC Hydro 2021 IRP. Appendix H-3, pages 1–2.
North American Electric Reliability Corporation. *Standard Application Guide TPL-001-4.* September, 2018. Table 1.
Western Electricity Coordinating Council. *Transmission System Planning Performance (TPL-001-WECC-CRT-3.2)*. June, 2019.

combinations of transmission and generation resource outage events that should be separately examined to ensure transmission system stability can be maintained. Though each of these scenarios is defined in a precise technical fashion, they are commonly referenced in shorthand such as by reference to "N-1" (a contingency in any single transmission or generation element), "N-1-1" (a contingency in two transmission or generation elements), "N-G" (contingency in the largest generation resource), or similar terms.

Among the seven defined NERC contingency scenarios, the most binding for the Vancouver Island subregion is the N-G-1 scenario.[26] The multiple contingency N-G-1 corresponds to the system's operation after a sequence of failures based an outage of the largest power generation resource on the island, followed by the loss of the most critical transmission line (in this case the 500 kV submarine cable drawing power from Lower Mainland to Vancouver Island).

# III. British Columbia's Reliability Standards Are in Alignment with Standard Industry Practice

BC Hydro's system-wide and locational supply adequacy standards are in alignment with those used across other Canadian and US utilities, independent system operator (ISOs), and regional transmission organizations (RTOs). However, as I illustrate via a benchmark comparison, there are regional differences in units of measure, accounting conventions, and underlying risk drivers that must be taken into account in such a comparison.

## A. Reliability Standard Units of Measure

One challenge in conducting a precise comparison of reliability standards across different utility systems is that the regions may differ in units of measure and other region-specific conventions. The term "1-in-10" is a particularly challenging term in that it is widely used across almost all Canadian and US power systems, but in some cases can be differently interpreted as either: (a) 0.1 days/year LOLE as used by BC Hydro; (b) 0.1 events/year loss of load events (LOLEv); and (c) 2.4 hours/year loss of load hours (LOLH). As a practical matter, 0.1 LOLE and 0.1 LOLEv are often similar or identical given that many models will predict only one event in any simulated day.

---

[26] This specifically refers to Category P3 Multiple Contingency scenario in Table 1. See NERC. *Standard Application Guide TPL-001-4.*

However, 0.1 LOLE and 2.4 LOLH are materially different measurements of reliability that can correspond to multiple percentage points difference in the relevant reserve margin.[27]

For the purposes of clarity, Table 1 summarizes the definitions of alternative reliability metrics and their differences in units of measure that I use consistently throughout this evidence. These are the same definitions described in the RCIA/Midgard Evidence and utilized in BC Hydro's 2021 IRP.[28] These are not the same definitions as utilized and described in the Capital Power Policy Evidence and Brankovich Evidence, but one can readily translate because the Brankovich Evidence clearly presents all results in the relevant units of measure.[29]

**TABLE 1: RELIABILITY METRICS USED TO MEASURE SUPPLY ADEQUACY IN POWER SYSTEMS**

| Reliability Metric | Unit of Measure | Description |
|---|---|---|
| **Loss of Load Expectation (LOLE)** | Days/year | Measurement as used in BC Hydro's system (0.1 days/year LOLE)<br>Measures expected number of days with inadequacy supply each year (regardless of the number, depth, or duration of events in that day) |
| **(Loss of Load Events (LOLEv)** | Events/year | Measures the number of supply shortfall events pear year (regardless of the depth or duration of those events) |
| **Loss of Load Hours (LOLH)** | Hours/year | Measures the number of hours with supply shortfall events per year (regardless of the number of events, or depth of those events) |
| **Expected Unserved Energy (EUE)** | MWh/year | Measures the expected MWh of energy not served due to supply shortfall events per year (regardless of the number of events or depth of any specific event) |
| **Normalized EUE or Loss of Load Probability (LOLP)** | % of annual energy lost | Measures the estimated annual energy unserved as a percentage of total annual energy |

## B. Inter-Regional Survey of Supply Adequacy Standards

Table 2 summarizes the system-wide and locational supply adequacy standards used by BC Hydro in comparison to those used by several other utilities and RTO/ISO systems across Canada and the US. The table also summarizes each system's peak demand, whether that demand arises in the summer or winter season, and the system reserve margin that the utility or system operator has estimated is needed to meet the defined reliability standard. In some systems, the reserve

27 Samuel Newell, Rebecca Carroll, Ariel Kaluzhny, Kathleen Spees, et al. *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region 2018 Update*. Prepared for ERCOT. December, 2018.

Johannes P. Pfeifenberger, Kathleen Spees, Kevin Carden, Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications*. Prepared for the Federal Energy Regulatory Commission (FERC). September, 2013.

28 RCIA/Midgard Evidence. Pages 27–28.

29 Brankovich Evidence. Pages 5–6.

margin requirements are presented on both an installed-based capacity (ICAP) basis in which thermal resources are measured at their maximum capacity ratings, as well as on an unforced capacity (UCAP) basis that discounts the capacity value of all resources to account for typical forced outage rates and resource intermittency.[30] BC Hydro's capacity reserve reporting approach is not precisely comparable to either ICAP or UCAP accounting, but is somewhat in between. BC Hydro reports capacity reserves as a percentage of total dependable capacity supply, with capacity derating factors reflective of fuel (i.e., water) supply constraints but that are not de-rated to account for forced outages.

**TABLE 2: RELIABILITY STANDARDS ACROSS REGIONS AND POWER SYSTEMS: SYSTEM WIDE, LOCATIONAL AND RESULTING RESERVE MARGIN REQUIREMENTS**

| Region | System-Wide Standard | Locational Standard | Peak Demand | Reserve Margin |
|---|---|---|---|---|
| **BC Hydro [1]** | 1 in-10 (0.1 LOLE) | Deterministic: N-G-1 (e.g., Vancouver Island) | 10,861 MW (Winter) | 12% (Dependable Capacity Reserve) |
| **ISO-NE [2]** | 1-in-10 (0.1 LOLE) | Deterministic: N-1-1<br>Probabilistic: 0.05 LOLE (in addition to system shortfalls) | 27,743 MW (Summer) | 13.5% ICAP |
| **CAISO [3]** | 1-in-10 (0.1 LOLEv) | Deterministic: N-1, N-1-1 and N-2 | 45,866 MW (Summer) | 17.5% ICAP |
| **PJM [4]** | 1-in-10 (0.1 LOLE) | Deterministic: N-1-1<br>Probabilistic: 1-in-25 (0.04 days/year) in addition to system shortfalls | 148,938 MW (Summer) | 14.9% ICAP (9.3% UCAP) |
| **NYISO [5]** | 1-in-10 (0.1 LOLE) | Deterministic: N-1-1<br>Probabilistic: Locational quantities adjusted to optimize total cost, subject to system-wide 0.1 LOLE | 31,765 MW (Summer) | 19.6% ICAP (7.9% UCAP) |
| **Newfoundland and Labrador [6]** | Historically: 2.8 LOLH. Proposed: 0.1 LOLE<br>+Annual energy needs assessment | Deterministic: 10-minute and 30-minute operational reserve requirement + N-1 for Labrador-Island Link | 1,983 MW (Winter) | 13% (excludes reliance on intertie) |
| **Maritimes [7]** | Probabilistic: 1-in-10 (0.1 LOLE)<br>Deterministic: 20% reserve margin | Deterministic: Contingency and transfer capability based on NPCC's standards; and maximum (20-15% of firm peak demand or largest contingency)<br>Probabilistic: system-wide 0.1 LOLE (but measured with intra-area transmission limits) | 5,583 MW (Winter) | 20% ICAP |
| **Ontario [8]** | 1- in-10 (0.1 LOLE) | Deterministic: N-1 + sensitivity studies to assess the impact of outages of local generation | 24,260 MW (Summer) | 18% ICAP |

30 Estimated systemic reserve margins based on installed capacity (often adjusted for weather/temperature conditions).

| | | | | |
|---|---|---|---|---|
| **MISO [9]** | 1- in-10<br>(0.1 LOLE) | Deterministic: transfer capability studies for zones (contingency-based N-1 cases)<br>Probabilistic: 1-in-10 (0.1 LOLE) in addition to system-wide events | 122,076 MW<br>(Summer) | 17.9% ICAP<br>(8.7% UCAP) |
| **ERCOT (Texas) [10]** | Historically: No standard (but policy informed by "economic" reserve margin analysis)<br>Proposed: Standard to be reviewed and adopted | Deterministic: N-1 and N-1-1 scenarios | 77, 884 MW<br>(Summer) | No requirement (policy informed by 13.75% ICAP as economic guideline) |
| **Manitoba Hydro [11]** | 1-in-10<br>(0.1 LOLE)<br>+Annual energy needs analysis | Deterministic: N-1 and other contingency scenarios | 5,754 MW<br>(Winter) | 12% ICAP |
| **Quebec [12]** | 1-in-10<br>(0.1 LOLE) | Deterministic: Contingency and transfer capability based on NPCC's standards | 40,960 MW<br>(Winter) | 11.9% |
| **Southern Company (Georgia Power) [13]** | Consider both 1-in-10 (0.1 LOLE) and economic cost minimizing reserve margin | Deterministic: N-1 and N-G-1 analyses for load pockets | 33,346 MW<br>(Summer) | 16.25% ICAP |
| **SPP [14]** | 1-in-10<br>(Currently 0.1 LOLE,<br>Historically 2.4 LOLH) | Deterministic: N-1 in addition to system events.<br>Probabilistic: 1-day-in-10-years LOLE (0.1 LOLE) and additional analysis when region is 75% hydro-based generation | 53,383 MW<br>(Summer) | 12% ICAP |

Sources and Notes:

Peak Demand: Forecast for full-year 2022, summer 2022 or winter 2022/23 for most systems, exceptions are Ontario IESO (Summer 2023), MISO (June 2022-May 2023), and Southern Company (Summer 2025).

[1] BC Hydro Integrated Resource Plan Technical Advisory Committee (TAC). 2020. Pages 26 (System Standard Column), 29 (Reserve Margin Column). BC Hydro Response to Intervener IR1. 2020. Exhibit B-10. Page 2 (Locational Standard Column). BC Hydro Integrated Resource Plan Application. 2022. Page 5-3 (Peak Demand Column).

[2] ISO-NE Installed Capacity Requirement (ICR) Reference Guide. 2021. Pages 8 (System Standard Column), 14, 24 (Locational Standard Column). New England's Electricity Use. 2022. Page 4 (Peak Demand Column). ISO-NE Net Installed Capacity Requirements (ICRs), Representative Future Net ICRs and Operable Capacity Analysis. 2022. Page 5 (Reserve Margin Column).

[3] CAISO Local Capacity Technical Study. 2022. Page 11 (Locational Standard Column). CAISO Summer Loads and Resources Assessment. 2022. Page 5 (System Standard, Reserve Margin, Peak Demand Columns).

[4] PJM Reserve Requirement Study. 2022. Page 8 (System Standard Column, Reserve Margin Column). Current Reliability Metrics in PJM's Resource Adequacy Construct. 2021. Page 2 (Locational Standard Column). PJM 2022 Long-Term Load Forecast Predicts Slight Growth. 2022 (Peak Demand Column).

[5] NYISO Comprehensive Reliability Plan. 2021. Pages 20 (Locational Standard Column), 24 (System Standard Column). NYISO Reliability Needs Assessment. 2022. Page 19 (Peak Demand Column). NYISO Installed Capacity Requirement Appendices. 2022. Page 55 (Reserve Margin Column). NYISO Locational Minimum Installed Capacity Requirements Determination Process. 2021 (Locational Standard Column).

[6] Newfoundland and Labrador Hydro Reliability and Resource Adequacy Study 2022 Update. 2022. Section 3.2.1. Page 10 (System Standard Column), Volume I: Study Methodology and Planning Criteria. Section 3.2.2. Page 11 (Locational

Standard Column), Volume III: Long-Term Resource Plan. Attachment 2. Page 2 (Peak Demand Column). Newfoundland and Labrador Hydro Reliability and Resource Adequacy Study. 2018. Page 43 (Reserve Margin Column).

[7] Maritimes Area Comprehensive Review of Resource Adequacy. 2022. Pages II (System Standard Column, Reserve Margin Column), 2 (Peak Demand Column), 3 (Locational Standard Column).

[8] Ontario IESO Annual Planning Outlook. 2022. Pages 41 (System Standard Column, Locational Standard Column), 43 (Peak Demand Column). Ontario Reserve Margin Requirements: 2017–2021. 2016. Page 1 (Reserve Margin Column). Ontario Resource and Transmission Assessment Criteria. 2007. Page 9 (Locational Standard Column).

[9] MISO Planning Year 2022-2023 Loss of Load Expectation Study Report. 2021. Pages 22 (System Standard Column), 23 (Locational Standard Column), 24 (Peak Demand Column, Reserve Margin Column), 39 (Locational Standard Column).

[10] Assessment of Market Reform Options to Enhance Reliability of the ERCOT System. 2022. Page 7 (System Standard Column). Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2022. 2022. Page 1 (Peak Demand Column).ERCOT Resource Adequacy. Planning Reserve Margin Analysis (Reserve Margin Column). ERCOT Planning Guide. 2022. Pages 3-1, 3-2 (Locational Standard Column).

[11] Manitoba Hydro Long-Term Development Plan. 2016. Pages 56 (System Standard Column), iii (Locational Standard Column). Manitoba Hydro 2023/24 & 2024/25 General Rate Application. 2022. Appendix 5.5, Page 1 (Reserve Margin Column), Appendix 5.6, Page 1 (Peak Demand Column).

[12] 2022 NPCC Québec Interim Review. 2022. Pages 2 (System Standard Column, Peak Demand Column), 6 (Reserve Margin Column). 2020 NPCC Québec Comprehensive Review of Resource Adequacy. 2020. Page 22 (Locational Standard Column).

[13] Southern Company 2022 Carbon Disclosure Project (CDP) Climate Change Disclosure. 2022. Page 31 (System Standard Column). Georgia Power 2022 Integrated Resource Plan. 2022. Pages 1–2 (Reserve Margin Column), H-168 (Locational Standard Column). Study of the Target Reserve Margin for the Southern Company System. 2022. Page 10 (Peak Demand Column).

[14] 2021 SPP Loss of Load Expectation Study. 2022. Page 43 (System Standard Column, Locational Standard Column). 2022 SPP Resource Adequacy Report. 2022. Pages 1 (Reserve Margin Column), 4 (Peak Demand Column). 2010 Loss of Load Expectation Report. 2010. Page 1 (Prior Standard)

## C. How BC Hydro’s System-Wide Supply Adequacy Standard Compares to Other Regions

The 1-in-10 standard utilized by BC Hydro is the same standard that has been adopted across almost all North American electricity systems, though some regions use slight differences in the units of measure for interpreting the standard. The most common interpretation of 1-in-10 is either a 0.1 days/year LOLE or 0.1 events/year LOLEv standard.[31] A different and less common interpretation of 1-in-10 is the 2.4 LOLH standard.

Comparing reserve margins is a less robust way to compare systems, given that different regions utilize a wide range of alternative reserve margin reporting conventions. Examples of common differences in reserve margin accounting include: (a) tabulation of supply resources’ contribution based on ICAP, UCAP, dependable capacity, or effective load carrying capability (ELCC); (b) inclusion or exclusion of intertie capability in the reserve margin; (c) treatment of demand and

[31] In most cases, the 0.1 days/year metric is reported rather than events/year, but many utilities and ISO/RTO systems use these two units of measure interchangeably, in part because the measured values can be the same or identical in many systems. The estimated days/year with events will be the same as the estimated events/year as long as there is only one event expected in any shortage day (i.e. typical in systems with one (net) peak load event per day). However, if a system is characterized by two (net) peak load events per day both of which can produce shortfall events, then the two metrics can diverge.

distributed resources on the supply or demand side; and (d) reflection of capacity reserves or peak load reserve margin. These differences in methodologies and conventions have been the subject of prior industry studies, and indicate that different accounting conventions can contribute to at least +/-5 percentage points difference in reserve margins for any given reliability level. [32]

Another reason that comparing reserve margins across systems is less robust is that the underlying risk drivers differ. Depending on the system in question, the most challenging conditions may occur during summer heat waves, during a cold snap when gas supply is unavailable, in a low hydro year, in the evening as solar resources drop off, or during a multi-week wind drought. Resource mix, system size, and level of dependence on interties also factor into the level of exposure to reliability risks. For these reasons, the same reserve margin will not produce the same level of reliability in two different systems, even if using the same accounting conventions.

Considering these differences across systems, I do not recommend to consider adopting the 8.4-10% reserve margin range suggested in the RCIA/Midgard Evidence, which was informed primarily by a comparison to the 8.4% Midcontinent ISO (MISO) UCAP reserve margin.[33] There are multiple reasons that MISO's system may maintain 1-in-10 reliability at a lower quoted reserve margin than BC Hydro, likely the most important of which is that the MISO system is ten times larger and so benefits from high levels of load and supply diversity that make it less susceptible to coincident reliability risks. MISO has estimated that based on these diversity benefits, it was able to reduce its reserve margin requirement by 3.3%-5.1% compared to what it would be if its member utilities were to meet reliability needs individually across separate smaller systems.[34]

The RCIA/Midgard evidence has also suggested to update the reserve margin accounting convention from a 12% "generation centric" to a 12% "load centric" reserve margin, and thereby reduce the quantity of capacity that must be maintained.[35] The RCIA/Midgard evidence further

---

[32] Astrape Conulting. *The Economic Ramifications of Resource Adequacy White Paper*. Prepared for EISPC and NARUC. January, 2013.

Johannes P. Pfeifenberger, Kathleen Spees, Kevin Carden, Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications*. Prepared for the Federal Energy Regulatory Commission (FERC). September, 2013. Page iii.

[33] In the above table, I report MISO's reserve margin at 8.7% UCAP consistent with the 2022 planning year, while the 8.4% quoted by RCIA/Midgard Evidence referenced the value for a different planning year.

Source for 8.7% and 8.4% UCAP. MISO. *2023/24 PY Planning Reserve Margin and Local Reliability Requirements—Draft Results*. September, 2022. Page 14.

[34] Values quoted on an ICAP reserve margin basis. Midcontinent ISO. *2021 MISO Value Proposition: Detailed Calculation Description*. *Pages 22–23.*

[35] RCIA/Midgard Evidence. Pages 7, 30–33, 43–44.

cites this approach to reserve margin calculation as best practice identified in a Northwest Power Pool (NWPP) report.[36] For the purposes of improving clarity and aligning with common practice, I tend to agree with the RCIA/Midgard Evidence and the NWPP report that a load centric calculation is somewhat preferable. However, RCIA/Midgard Evidence is not correct in its assertion that adopting an alternative accounting convention would reduce total capacity requirements. The MW quantity of capacity needed to avoid shortfall events is dictated by the 0.1 LOLE reliability standard, not by differences in the reserve margin reporting convention. Using the terms coined in the RCIA/Midgard Evidence: a 12% generation-centric reserve margin would provide equivalent reliability value to a 13.6% load-centric reserve margin.[37] Under both accounting conventions, the 0.1 LOLE reliability standard would be achieved as long as the reserve margin accounting is self-consistent with the accounting used in conducting the reliability modeling. For these reasons, selecting between the two options is a matter of convention and clarity.

Most policymakers across Canada and the US have chosen to adopt reliability standards based only on reliability needs, rather than considering the economic implications as recommended in the RCIA/Midgard evidence. There are informative exceptions however, where policymakers and utilities have considered the tradeoffs in reliability and cost when adopting a reliability standard. Examples of jurisdictions where economics have been considered in the development of reliability standards include Texas, several utilities in the US Southeast, Australia, and Great Britain.[38] If conducting such a review, the costs of shortage events can be compared to the costs of maintaining higher levels of supply to estimate an "economically optimal" or least-cost planning reserve margin. Policymakers can then consider economic and reliability outcomes in expectation in a typical year, as well as under extreme events, when determining the most desirable supply adequacy standard. The cost and reliability tradeoffs associated with inter-regional electricity trade can also be examined, including the regional reliability drivers identified in the CEBC/Lusney Evidence.[39]

---

[36] Northwest Power Pool. *Exploring a Resource Adequacy Program for the Pacific Northwest: An Energy System in Transition*. October 2019.

[37] Putting specific numbers to the conversion: consider a year with peak load of 12,000 MW. The generation-centric 12% capacity reserves approach determines the total quantity of supply needed as 12,000 MW ÷ (1 – 12%) = 13,636 MW of supply. The load-centric 13.6% reserve margin approach determines the identical quantity of supply needed as 12,000 MW × (1 + 13.63%) = 13,636 MW. (In this example for simplicity, I assume that the share of resources assessed on an effective load carrying capability basis is zero.)

[38] Substantial academic and industry literature examines the topic of economically-informed reliability standards. As examples of relevant studies see: Johannes P. Pfeifenberger, Kathleen Spees, Kevin Carden, Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications*. Prepared for the Federal Energy Regulatory Commission (FERC). September, 2013.

Toby Brown, Neil Lessem, Roger Lueken, Kathleen Spees, Cathy Wang. *High-Impact, Low-Probability Events and the Framework for Reliability in the National Electricity Market*. Prepared for The Australian Energy Market Commission. February, 2019.

Astrape Conulting. *The Economic Ramifications of Resource Adequacy White Paper*. Prepared for EISPC and NARUC. January, 2013.

[39] See CEBC/Lusney Evidence. Pages 10, 16–17.

The current BCUC-approved 0.1 LOLE supply adequacy standard does not incorporate the consideration of economics in the determination of supply needs, though tradeoffs in reliability and cost could be considered in the future if the BCUC wished to reconsider or otherwise update the standard.

## D. How BC Hydro's Locational Planning Standards Compare to Other Regions

Locational transmission planning and supply adequacy standards vary more widely across regions, owing in part to the unique characteristics of supply and transmission that pose the greatest reliability concerns. The same deterministic NERC TPL-001-4 planning standards apply to BC Hydro and other transmission planning entities across Canada and the US, though differences exist in terms of which contingency scenarios are binding (e.g. N-1, N-1-1, etc.) and in terms of how the transmission planning standards are coordinated with generation supply planning activities. For example, the ISO/RTO regions that conduct organized capacity markets with locational resource adequacy standards incorporate these deterministic standards when establishing locational capacity procurement requirements.

A subset of regions I reviewed in this benchmarking exercise have also adopted probabilistic locational supply adequacy standards. Probabilistic locational supply adequacy standards are commonly used (in addition to deterministic standards) in large ISO/RTO regions where the subregions in question align with the individual utility areas relative to which supply adequacy was previously managed. For regions that adopt location-specific probabilistic resource adequacy standards, one typical approach is to define these as conditional LOLE standards (or location-specific shortfall events, measured as if the broader system could be assumed to be perfectly reliable). For example in PJM Interconnection (PJM) case, a 0.04 days/year LOLE applied to Local Deliverability Areas (LDA) means that customers sited in a determined LDA could potentially face up to 0.14 days/year load shedding risk (0.1 systemic LOLE + 0.04 locational LOLE) if none of the events in question were to occur on the same days. In MISO, customers in the most import-constrained subregions could face up to 0.2 days/year LOLE risk (0.1 systemic LOLE + 0.1 locational LOLE).

The BCUC has not previously reviewed or accepted a probabilistic locational supply adequacy standard, but such a probabilistic locational standard could be evaluated and adopted in the future. If such a probabilistic standard were adopted it would be used alongside the deterministic locational transmission planning standards (with the more stringent of the two standards determining the quantity of required resources in any given planning cycle).

# IV. BC Hydro's Proposed Supply Plan in Vancouver Island Meets the Approved Locational Planning Standards, Even without Island Generation Facility

The Capital Power Policy Evidence and Brankovich Evidence assert that the BC Hydro 2021 IRP will produce reliability below the defined reliability standard on Vancouver Island, and that retaining Capital Power's Island Generation facility in an online status will partly or fully mitigate the anticipated reliability shortfalls.[40] This intervener evidence conflicts with BC Hydro's assessment that its supply plan for Vancouver Island will meet supply adequacy needs, which is summarized in Chapter 5 of the BC Hydro 2021 IRP.[41]

The reason for the discrepancy is that the two assessments have been conducted relative to two different locational supply adequacy standards. The Brankovich Evidence applies a hypothetical probabilistic locational reliability standard of 2.4 hours/year LOLH to Vancouver Island, and concludes that any shortfall relative to that standard signals a need for incremental capacity. This hypothesized locational probabilistic reliability standard has not previously been reviewed or approved by the BCUC.[42]

In comparison, the BC Hydro 2021 IRP has conducted its supply adequacy assessment relative to the locational transmission planning standards, of which the N-G-1 scenario was deemed the most binding. Relative to this BCUC-approved planning standard, Vancouver Island was assessed to have sufficient resources even without Island Generation.

As discussed above, if the BCUC wished to consider adoption of a probabilistic locational standard, this could be considered in the context of tradeoffs in reliability and cost across a range of potential probabilistic reliability levels that could be considered. If a probabilistic locational supply adequacy standard is developed it would be considered alongside the deterministic transmission planning standards, with the more stringent of the two standards stipulating the quantity of supply needs. Once the MW quantity of locational supply needs is determined, the

---

40 Capital Power Policy Evidence. Pages 2, 11–12; Brankovich Evidence. Table 4 and Pages 22–23.

41 BC Hydro 2021 IRP. Chapter 5 (Load Resource Balances Before Planned Resources), Appendixes B and D.

42 The Brankovich Evidence also interprets the 1-in-10 standard in units of hours/year rather than the units of days/year utilized in the system-wide standard, but I expect that the analysis could be readily updated in order to report both metrics.

planning process can consider economic, policy, social, and other objectives to determine which supply resource may be the most attractive option for fulfilling the defined need.

# V. Findings in Consideration of Interveners' Comments

### FINDING 1: THE PROPOSED IRP IS CONSISTENT WITH BCUC-APPROVED STANDARDS

As documented in the body of this evidence, the BC Hydro 2021 IRP aligns with the supply adequacy standards approved by the BCUC. These include the 0.1 LOLE system-wide probabilistic supply adequacy standard, and the NERC-developed locational transmission planning standards.

Adopting either of the two reserve margin adjustments recommended in the RCIA/Midgard Evidence would reduce system-wide reliability to below the BCUC-approved 0.1 LOLE standard. Reducing the reserve margin to a lower 8.4-10% reserve margin would produce lower reliability than the 12% capacity reserves level that BC Hydro has estimated would be needed to align with 0.1 LOLE. Shifting from a generation-centric (12% percent of dependable capacity) to a load-centric (12% of peak load) convention would similarly reduce reliability if implemented as recommended in the RCIA/Midgard evidence. Adopting a load-centric convention may offer benefits of enhanced clarity, but would require the reserve margin to be updated to approximately 13.6% if the 0.1 LOLE standard is to be maintained.

### FINDING 2: CURRENT SUPPLY ADEQUACY STANDARDS ARE IN ALIGNMENT WITH STANDARD INDUSTRY PRACTICE

BC Hydro's system-wide and locational supply adequacy standards are in alignment with standard practice in other regions, though a robust cross-regional comparison requires careful treatment of differences in units of measure, accounting conventions, and underlying reliability drivers.

The 1-in-10 LOLE standard used by BC Hydro is the most commonly-used standard across Canada and the US, though there are substantial differences in the reserve margin needed to meet that reliability standard due to differences in accounting conventions and underlying drivers of reliability risk. BC Hydro's deterministic locational transmission planning standards are also consistent with standard industry practice, though some regions have adopted probabilistic locational supply adequacy standards in addition to deterministic standards.

Most jurisdictions have not considered the economic costs of reliability in establishing supply adequacy standards. However, an informative subset of jurisdictions have conducted analyses of economic and reliability tradeoffs such as suggested in the RCIA/Midgard Evidence.

### FINDING 3: VANCOUVER ISLAND'S SUPPLY PLAN WILL MEET THE LOCATIONAL PLANNING STANDARDS, EVEN WITHOUT ISLAND GENERATION

On Vancouver Island, the supply plan proposed in the BC Hydro 2021 IRP is consistent with the current BCUC-mandated local supply adequacy standard, even without Island Generation. The Brankovich Evidence finds that supply is inadequate because it measures supply adequacy relative to a more stringent standard recommended by the intervener (but that has not been reviewed or approved by the BCUC).

### FINDING 4: IF THE BCUC WISHES TO REVIEW OR UPDATE SUPPLY ADEQUACY STANDARDS, I RECOMMEND TO CONDUCT A COMPREHENSIVE REVIEW

If the BCUC wishes to reconsider or otherwise update its current supply adequacy standards, I recommend to do so in full consideration of all relevant policy tradeoffs including those highlighted by interveners. In particular, such a review should weigh the advantages of accepting lower levels of reliability (primarily the advantage of reducing supply investment costs, as emphasized in the RCIA/Midgard Evidence) compared to the advantages of increased reliability (as emphasized in the Capital Power Policy Evidence and the CEBC/Lusney Evidence).

Brattle

# Dr. Kathleen Spees

**PRINCIPAL**

Washington, DC | 412.445.2694 | Kathleen.Spees@brattle.com

Dr. Spees is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Her work for market operators, regulators, regulated utilities, and market participants focuses on:

- Wholesale Power Market Reform
- Carbon and Environmental Policy
- Capacity Market Design
- Wholesale Energy, Ancillary Service, and Specialized Products Market Design
- Generation and Transmission Asset Valuation
- Integration of Emerging Technologies

Dr. Spees has worked in more than a dozen international jurisdictions supporting the design and enhancement of environmental policies and wholesale power markets. Her clients include electricity system operators in PJM, Midcontinent ISO, New England, Ontario, New York, Alberta, Texas, Italy, Singapore, and Australia. Electricity market design assignments involve ensuring adequacy of capacity and energy market investment incentives to achieve reliability objectives at least cost; designing carbon and environmental attribute markets and incentives to support efficient clean energy transition; modeling projected outcomes in electricity markets and multi-sector carbon markets; enhancing operational reliability and efficiency through energy market, scarcity pricing, and ancillary service market improvements; effectively integrating intermittent renewables, storage, demand response, and other emerging technologies; evaluating benefits and costs of industry reform initiatives; and enhancing efficiency at market interties.

Dr. Spees conducts detailed power and energy system modeling analyses to inform reliability, cost, environmental and equity outcomes under alternative clean energy transition pathways. Dr. Spees regularly provides expert support in the context of stakeholder engagements and regulatory hearings.

## EDUCATION

Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center in 2008 and her MS in Electrical and Computer Engineering from Carnegie Mellon University in 2007. She earned her BS in Physics and Mechanical Engineering from Iowa State University in 2005.

# Representative Experience

## WHOLESALE POWER MARKET REFORM

**Ontario Market Renewal Benefits Case.** For the Ontario Independent Electricity System Operator (IESO), developed an analysis evaluating the benefits and implementation costs associated with fundamental reforms to wholesale power markets, including implementing nodal pricing, a day-ahead energy market, enhanced intra-day unit commitment, operability reforms, an enhanced intertie design, and a capacity market. Analysis included: (a) market visioning sessions with IESO staff and stakeholders to identify future market design requirements; (b) identify primary drivers and quantify system efficiency benefits; (c) review lessons learned from other markets' reforms to identify opportunities and reform risks; (d) conduct a bottom-up analysis of implementation costs for replacing market systems; and (e) evaluate interactions with existing supply contracts.

**MISO Market Development Vision.** For the Midcontinent Independent System Operator (MISO), worked with staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.

**Australia NEM Electricity Market Vision for Enabling Innovation and Clean Energy.** On behalf of the Australian Energy Market Operator reviewed electricity market design options for the future of the NEM. Evaluated opportunities for relying on markets, innovation, and new technologies to address a range of challenges in the context of significant increases in customer costs, high gas prices, large clean energy penetration, coal retirements, uncertain carbon policies, and emerging reliability and security concerns.

**Thailand Power Market Reform.** Supported market design options and recommendations for potential power market reforms in Thailand, including the introduction of forward, day-ahead, and real-time energy markets, as well as the potential introduction of a bilateral or centralized capacity market. Examined interactions with retail rates, existing contracts, and self-supply arrangements.

**Power Market Reform to Accommodate Decarbonization and Clean Energy Policies.** For the system operator in a jurisdiction pursuing significant clean energy and decarbonization policies, assisted in evaluating market design alternatives. Estimated energy price, customer cost, and reliability implications under alternative energy, ancillary service, and capacity market design scenarios. Quantified implications of key uncertainties such as intermittent resource penetration levels and impacts of interties with external regions. Provided research and comparative analysis of design alternatives and lessons learned from other jurisdictions.

**Western Australia Power Market Reform Options.** For EnerNOC, developed a whitepaper describing high-level market reform options in the face of escalating customer costs in Western Australia. Described the drivers of capacity payment costs in comparison to other major cost driver. Identified high-level options for pursuing capacity and energy-only market design reforms, comparing advantages and disadvantages.

**Russian Capacity and Natural Gas Market Liberalization.** On behalf of a market participant, conducted an assessment of market design, regulatory uncertainty, and liberalization success. Focus was on the efficiency of market design rules in the newly introduced system of capacity contracts combined with capacity payments, as well as on the impacts of gas price liberalization delays.

**PJM Review of International Energy-Only, Capacity Market, and Capacity Payment Mechanisms.** For PJM Interconnection, conducted a review of energy-only markets, capacity payment systems, and capacity markets on behalf of PJM market operator. Reviewed reliability, volatility, and overall investment outcomes related to details of market designs in bilateral, centralized, and forward commitment markets.

**Options for Reconciling Regulated Planning and Wholesale Power Markets in in MISO.** For NRG, developed a whitepaper assessing reliability and economic implications of current capacity market and integrated planning approaches, and the challenges in accommodating retail access and integrated planning within the same market region. Recommended options for enhancing the MISO capacity market and regulated entities' approaches to planning.

**Review of California Planning and Market Mechanisms for Resource Adequacy.** For Calpine, evaluated interactions and implications of California's policy, planning, and market mechanisms affecting resource adequacy. Recommended improvements to reconcile inconsistencies and enhance efficiencies in regulated long-term procurements, short term local resource adequacy construct, and CAISO backstop mechanisms.

### CARBON AND ENVIRONMENTAL POLICY

**Greenhouse Gas Cap-and-Trade Market Design and Modeling.** For the New York City Mayor's Office of Sustainability, conducted a study to develop market design options for a greenhouse gas cap-and-trade market under Local Law 97 that imposes 80% carbon reductions on large buildings in New York City by 2050. Utilized Brattle's Decarbonized Energy Economy Planning (DEEP) model to assess the outcomes of alternative market designs including cost, pricing, emissions, City revenues, distributional impacts, and implications on environmental justice communities.

**Design of a Competitive Forward Clean Energy Market.** For NRG, developed a market design to attract investment in clean energy resources to serve state policy goals and customer demand for clean energy. Developed detailed design proposal for integrating and aligning the market with wholesale electricity markets and competitive retail markets. Supported drafting of state legislation and testimony before state legislature.

**Integrating Markets and Public Policy in New England.** For a coalition of stakeholders, engaged in a collaborative effort to develop market-based approaches for accommodating and achieving state decarbonization objectives. Developed and refined design proposals including carbon pricing and market-based clean energy procurements, while identifying options for reducing regulatory uncertainties, avoiding cross subsidies across states, and mitigating customer cost impacts. Evaluated options for improving interactions with existing energy, capacity, renewable energy credit, and carbon markets. Conducted modeling of price, cost, and emissions outcomes under a range of designs. Engaged in an iterative process to develop, present, and refine design proposals based on input from a broad array of stakeholders. Provided expert support in outreach to state policymakers and industry groups.

**Ontario Market Evolution to Support a 90% Clean Energy System and Increasing Distributed Resources.** For the IESO, supported the activities of the non-emitting stakeholder committee to model market reforms necessary to fully enable the 90% clean energy fleet. Supported stakeholder workshops to identify potential futures with many more distributed resources, a range of technology costs, and a variety of market designs. Conducted modeling analysis to analyze market outcomes including cost, reliability, resource curtailment, and resource revenues.

**Locational Marginal Emissions.** Co-authored a whitepaper with ReSurety proposing an approach to valuing clean energy, demand reductions, and storage relative to locational, 5-minue carbon abatement value. Descripted the next generation of renewable procurements, contract incentives, sustainability accounting, and renewable energy credits in alignment with carbon abatement value.

**Advising on Federal Clean Energy Legislation (Multiple Clients).** Provided expert advice and language on the development of cost-effective clean energy legislation. Supported engagement with interest groups and legislative committee staff.

**National Carbon Policy Design and Interactions with Power Markets.** For an international regulator, analyzed a range of options for the design of a carbon policy for the electricity sector, considering impacts on the wholesale electricity market and interactions with other sectors. Analyzed a range of alternatives for intensity-based and cap-and-trade based approaches, alternative allocations methods, and interactions with renewables standards. Developed two detailed design alternatives within the specified policy constraints.

**Review of International Carbon Mechanisms.** For an RTO, conducted a survey of international carbon pricing, cap-and-trade, and rate-based mechanisms, and detailed review of design elements of the mechanisms implemented in Europe, California, Alberta, and the Regional Greenhouse Gas Initiative. Evaluated a range of alternatives for implementing the Clean Power Plan across states while effectively integrating with wholesale markets.

**New York ISO Carbon Pricing.** For the New York ISO, examined economic implications of a possible carbon pricing proposal within the wholesale electricity market. Developed a whitepaper evaluating interactions with state environmental policies, wholesale power markets, intertie pricing, capacity market, and transmission planning. Estimated energy price and customer cost impacts.

**Carbon Allowance Allocations Alternatives.** For the National Resources Defense Council, developed a whitepaper examining the advantages and disadvantages of auction-based, customer-based, and generator-based approaches to allocating carbon allowances. Developed recommendations for avoiding the introduction of inefficient investment, retirement, and operational incentives under each type of design, and for mitigating customer cost impacts.

**Power Market Impacts of Clean Power Plan Alternatives.** Conducted a modeling assessment of price, cost, and emissions implications of different rate-based, subcategory rate-based, and mass-based implementation of the Clean Power Plan in Texas. Estimated energy, emission reduction credit, and carbon prices under each scenario, and net revenue and operating implications for several types of generating plants.

**Review of Hydropower Industry Implications under Clean Air Act 111(d).** For the National Hydropower Association, provided members review of the implications for new and existing hydropower resources of proposed EPA Clean Power Plan under Clean Air Act Section 111(d). Analyzed impacts under a variety of potential revisions to the proposed rule, different potential state compliance options, differing plan regulatory statuses, mass-based vs. rate-based compliance, regulated planning vs. market-based compliance, and cooperative vs. stand-alone compliance.

**Enabling Canadian Imports for U.S. Clean Energy Policies.** For a coalition of Canadian electricity producers and policymakers, reviewed a range of options for U.S. states to pursue clean energy policies and the Clean Power Plan while enabling contributions from clean energy imports.

**Clean Power Plan Regulatory and Stakeholder Support.** For a cooperative entity, provided support in developing internal and external positioning associated with the Clean Power Plan. Analyzed state-wide emissions targets and compliance alternatives. Supported messaging and stakeholder engagement at the state and federal levels. Submitted testimony before the Environmental Protection Agency.

**State Compliance Strategy under the Clean Power Plan.** For a regulated utility, evaluated options and feasibility of meeting state standards under 111(d) rate standards under a number of compliance scenarios. Developed an hourly dispatch model covering backcast and forecast years through the interim and final compliance timelines, accounting for impacts of load growth, renewables growth, coal-to-gas redispatch, coal minimum dispatch constraints, planned retirements, new generation development, and export commitments. Estimated the ability to meet the standard under various compliance strategies.

**New Gas Combined Cycle Plants Under the Clean Power Plan.** For the National Resources Defense Council, developed a whitepaper evaluating the economic implications of Clean Power Plan implementation plans that do or do not cover gas combined cycle plants on a level basis with other fossil-emitting plants. Conducted simulation analyses comparing the economic and emissions implications of alternative approaches.

**MISO Coal Retrofit Supply Chain Analysis.** For the MISO, analyzed the fleet-wide requirements for retrofitting plants to upgrade for the Mercury and Air Toxics Standard. Reviewed the upstream engineering services, procurement, and construction supply chain to evaluate the ability to upgrade the fleet within the available time window. Analyzed the potential for operational and reliability concerns from simultaneous planned outages needed to support fleet-wide retrofit requirements in the MISO footprint.

**Impact of Environmental Policies on Coal Plant Retirement.** For a PJM market participant, conducted a zone-level analysis of PJM market prices and used unit-level data to conduct a virtual dispatch of coal units under a series of long-term capacity, fuel, and carbon price scenarios. Modeled retirement decisions of plants by PJM zone and the effect of the carbon price on the location and aggregate size of these retirement decisions.

## CAPACITY MARKET DEISGN

**PJM Review of Capacity Market Design and Demand Curve Parameters: 2011, 2014, and 2018.** For PJM Interconnection, conducted independent periodic reviews of PJM's Reliability Pricing Model. Analyzed market functioning for resource adequacy including uncertainty and volatility of prices, net cost of new entry parameters, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Developed a probabilistic simulation model evaluating the price volatility and reliability implications of alternative demand curve shapes and recommended a revised demand curve shape. Provided expert support to stakeholder proceedings, testimony submitted before the Federal Energy Regulatory Commission, and before the Maryland Public Service Commission.

**Integrated Clean Capacity Market (ICCM).** For the New Jersey Board of Public Utilities, supported a Board investigation of alternative resource adequacy structures in alignment with the state's 100% by 2040 economy-wide clean energy mandates. Developed detailed design proposal for the ICCM and conducted economic modeling of clean energy achievement and customer costs across alternative design structures. Supported a series of stakeholder engagements to review alternative structures.

**New York Capacity and Resource Adequacy Alternatives.** For the New York Department of Public Service and New York State Energy Research & Development Authority, conducted a study evaluating a range of capacity market and resource adequacy alternatives. Implemented modeling analysis of impacts across alternative capacity market designs, minimum offer price rule scenarios, and interactions with state clean energy mandates. Supported a technical workshop and authored reports filed within docket proceedings.

**Maryland Resource Adequacy Alternatives.** For the Maryland Environmental Service and Maryland Energy Administration, conducted an analysis of resource adequacy and capacity market alternatives in alignment with state clean energy policy. Conducted modeling analysis, authored a public report, and presented results to state policymakers.

**Alberta Energy-Only Market Review for Long-Term Sustainability: 2011 and 2013 Update.** For AESO, conducted a review of the ability of the energy-only market to attract and retain sufficient levels of capacity for long-term resource adequacy. Evaluation of the outlook for revenue sufficiency under forecasted carbon, gas, and electric prices, potential impact of environmentally-driven retirements, potential federal coal retirement mandate, and provincial energy policies.

**Singapore Capacity Market Design.** For the Energy Market Authority, supported market design and market rules development for all aspects of the new capacity market design. Supported an iterative series of stakeholder engagements to iteratively refine market rules.

**Economic Implications of Resource Adequacy Requirements.** For the U.S. Federal Energy Regulatory Commission, reviewed economic and reliability implications of resource adequacy requirements based on traditional reliability criteria as well as alternative standards based on economic criteria. Evaluated total system costs, customer costs, supplier net revenues, and demand response implications under a range of reserve margins as well as under different energy-only and capacity market designs.

**Winter Resource Adequacy and Reliability.** For an RTO, analyzed the risk of winter reliability and resource adequacy shortages. Examined the drivers of winter reliability concerns including unavailability of specific resource types, winter fuel supply shortages, and weather-driven outages. Developed a range of potential reforms for addressing identified concerns.

**Testimony on the Impacts of the Minimum Offer Price Rule.** For a coalition of environmental organizations, authored testimony on the economic impacts of the Minimum Offer Price Rule in the New York capacity market, filed before the Federal Energy Regulatory Commission.

**Alberta Capacity Market Design.** Supported the development of a capacity market design in Alberta. Provided expert support to public working groups and AESO staff to review analytical questions, develop and evaluate design alternatives, and draft design documents. Supported on all aspects of market design including establishing reliability requirements, developing demand curve parameters, evaluating seasonal capacity resources, setting capacity ratings, product definition and obligations, and penalty mechanisms.

**European Market Flexibility and Capacity Auction Design.** For European client, developed a market-based design for meeting flexible and traditional capacity needs in the context of high levels of intermittent resource penetration, degraded energy and ancillary pricing signals, and ongoing electricity market reforms. Engaged in meetings with industry and European Commission staff to develop and refine design options. Developed a model simulating market clearing results in a two-product auction and projecting prices over time.

**Italian Capacity Market Design.** For Italy's transmission system operator Terna, supported development of a locational capacity market design and locational capacity demand curves based on simulation modeling on the value of capacity to customers.

**Capacity Auction Design for Western Australia**. For Western Australia's Public Utility Office, drafted a whitepaper and advised on the design of its new capacity auction mechanism.

**IESO Capacity Auction Design.** Provided expert support to IESO staff in support of a new capacity auction design. Provided detailed memos describing options, tradeoffs, and lessons learned on every aspect of capacity auction design. Supported stakeholder engagement, conducted analysis of design alternatives, and developed design proposals.

**PJM Seasonal Capacity Market Design.** For the Natural Resources Defense Council, provided testimony and economic analysis in support of improving the capacity market design to better accommodate seasonal capacity resources.

**ISO New England Capacity Demand Curve**. For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve shapes. Submitted Testimony before the Federal Energy Regulatory Commission supporting a proposed system-wide demand curve, with ongoing support to develop locational demand curves for individual capacity zones.

**MISO-PJM Capacity Market Seams Analysis.** For MISO, evaluated barriers to capacity trade with neighboring capacity markets, including mechanisms for assigning and transferring firm transmission rights and cross-border must-offer requirements. Evaluated economic impacts of addressing the barriers and identified design alternatives for enabling capacity trade.

**MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before the Federal Energy Regulatory Commission.

**Capacity Market Manipulation.** For a market participant, supported economic and policy analysis of an alleged instance of capacity market withholding.

**Demand Curve and Net Cost of New Entry Review.** For an RTO, provided a high-level conceptual review of its approach to establishing demand curve and net cost of new entry parameters. Identified potential reliability and economic efficiency concerns, and recommended enhancements.

**Western Australia Reserve Capacity Mechanism and Transition Mechanism**. For EnerNOC, authored two public reports related to the energy market reforms in Western Australia. The first report evaluated the characteristics of the Western Australia Reserve Capacity Mechanism in comparison with international best practices and made recommendations for improvements, whether pursuing a capacity market or energy-only market design. The second report evaluated and recommended changes to the regulator's proposed mechanism for transitioning to its long-term capacity market design.

**MISO Resource Adequacy Construct.** For MISO, conducted a review of MISO's resource adequacy construct. Subsequent assistance to MISO in enhancing the market design for resource adequacy related to market redesign, capacity market seams, and accommodation of both regulated and restructured states. Provided background presentations to stakeholders on the capacity market design provisions of NYISO, PJM, CAISO, and ISO-NE.

**Cost of New Entry Study to Determine PJM Auction Parameters: 2011 and 2014.** For PJM Interconnection, partnered with engineering, procurement, and construction firm to develop bottom-up cost estimates for building new gas combined cycles and combustion turbines. Affidavit before the Federal Energy Regulatory Commission and participation in settlement discussions on the same

## WHOLESALE ENERGY, ANCILLARY, AND SPECIALIZED PRODUCTS MARKET DESIGN

**Greece Energy and Ancillary Service Market Reform.** For the Hellenic Association of Independent Power Producers, provided expert advice and a report on how to reform wholesale power markets to conform with policy mandates and meet system flexibility needs. Analyzed energy and ancillary market pricing and rules to identify opportunities to enhance efficiency, improve participation of emerging resources, achieve market coupling, and better integrate intermittent resources. Proposed high-level design recommendations for implementing forward, day-ahead, intraday, and balancing markets consistent with European Target Model requirements. Developed detailed design recommendations for near-term and long term enhancements to market operations, pricing, dispatch, and settlements. Provided expert support in meetings with European Commission staff.

**Ramping Product Design.** For a market operator, developed a design proposal for a ramping product that would serve system ramping needs across multiple forward intervals and across locations. Developed rules that would enable distributed and demand response resources to participate in providing system ramping needs and incentives to become visible and controllable by the system operator.

**Alberta Energy and Ancillary Service Market Enhancements.** Supported the development of market design enhancements to better support flexibility needs and align with capacity market implementation. Developed design proposals and evaluated alternatives for immediate and long-term reforms including monitoring and mitigation, enhanced administrative scarcity pricing, ancillary service co-optimization, day-ahead markets,

**SPP Ramp Product Proposal.** For Golden Spread Electric Cooperative, developed recommendations for the design and implementation of a ramping product to most efficiently and cost-effectively manage intermittency needs. Reviewed opportunities to determine the most appropriate quantity of resources, forward product timeframe, price formation, and interactions with existing pricing and commitment procedures.

**ERCOT Energy Market Design and Investment Incentives Review.** For the Electric Reliability Council of Texas (ERCOT), conducted a study to: (a) characterize the factors influencing generation investment decisions; (b) evaluate the energy market's ability to support investment and resource adequacy at the target level; (c) examine efficiency of pricing and incentives for energy and ancillary services, focusing on scarcity events; and (d) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Performed forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Supported ongoing proceedings with stakeholders and before the Public Utility Commission of Texas.

**Scarcity and Surplus Event Pricing.** For an RTO, examined the efficiency and reliability implications of its pricing mechanisms during scarcity and surplus events, and evaluated potential market reforms. Options reviewed included adjusting the price cap consistent with the value of lost load, adjusting supplier offer caps, imposing administrative scarcity prices at varying levels of emergency events, ancillary service market pricing interactions, and reducing the price floor below zero.

**MISO Wind Curtailment Interactions with Energy Market Pricing and Transmission Interconnection Processes.** For MISO, evaluated the efficiency and equity implications of wind curtailment prioritization mechanisms and options for addressing stakeholder concerns, including interconnection agreement types, energy and capacity injection rights, ARR/FTR allocation mechanisms, energy market offers, and market participant hedging needs.

**Survey of Energy Market Seams.** For the Alberta Electric System Operator (AESO), assessed the implications of energy market seams inefficiencies between power markets in Canada, the U.S., and Europe for the Alberta Electric System Operator. Evaluation of options for improving seams based on other markets' experiences with inter-regional transmission upgrades, energy market scheduling and dispatch, transmission rights models, and resource adequacy.

**New England Fuel Security Market Design.** For NextEra, developed design proposals for using market-based mechanisms to meet regional fuel security needs including through a fuel security reserve product that would enhance pricing and operations for fuel security in the energy and ancillary service markets, and options for a long-term solution through forward auctions for fuel security.

**Reliability Auctions for the NEM.** For the Australian Electricity Market Operator conducted an international review of the range of approaches to supporting reliability and system security through competitive auctions. Focused on product definition including, various aspects of reliability and system security, auctions focused on enabling non-traditional resource types, options ranging from strategic reserve models to partial needs procurements to capacity markets, and potential for impacts on energy-only market pricing and performance.

**ERCOT Operating Reserves Demand Curve and Economically Optimal Reserve Margin 2014 and 2018.** For the Public Utility Commission of Texas and ERCOT, co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.

**Financial Transmission Right and Virtual Bidding Market Manipulation Litigation for PJM.** For PJM Interconnection, analyzed financial transmission rights, energy market, and virtual trading data for expert testimony regarding market manipulation behavior.

**Southern Company Independent Auction Monitor.** For Southern Company, developed auction monitoring capability and protocol development for monitoring hourly and daily auctions. Supported functions included daily and annual audits of internal company processes and data inputs related to load forecasting, purchases and sales, and outage declarations. Analyzed company data to develop monitoring protocols and automated tools. Coordinated implementation of data collection and aggregation system required for market oversight and for detailed internal company data audits.

## GENERATION AND TRANSMISSION ASSET VALUATION

**Revenue Projections for Generation and Transmission Assets (Multiple Clients).** For multiple clients, top-line operating cost and revenues estimation for generation and transmission assets in PJM, ISO-NE, MISO, SPP, and ERCOT; experience with a range of asset types including gas CCs, gas CTs, coal, renewables, waste-to-energy, cogeneration, and HVDC lines. Evaluation exercises include forecasting market prices and net revenues from energy, capacity, ancillary service, and (if applicable) renewable energy credit markets. Valuations account for the operational impacts and economic value of existing power purchase agreements and other hedges. Clients typically require qualitative and quantitative analysis of regulatory risks under a range of operational and market scenarios. Valuation efforts often conducted in the context of due diligence for transactions, business decisions, and contract negotiations.

**Executive Education and Investment Opportunities Surveys (Multiple Clients).** For multiple clients, provided executive education and detailed survey material to support investments in new markets and strategic decision-making. Educational efforts provided over a range of levels including high-level executive sessions, all-day workshop sessions, and detailed support for analytical teams. Examples of subject matter include: (a) cross-market surveys comparing investment attractiveness in many dimensions based on market fundamentals, regulatory structure, and contracting opportunities; and (b) single-market deep-dive educational sessions on capacity, energy, ancillary service, and financial/hedging product functioning and market performance.

**In-House Fundamentals Capability Development (Multiple Clients).** For multiple clients, supported the development of in-house capability for market fundamentals analysis. Typically needed in the context of new entrants to a market or system operators expanding the scope of their internal analytical capabilities. Scope of support has included: (a) initial education, backup support, and advisory support for fundamentals teams entering a new market; (b) development and transfer of new purpose-built modeling tools such as capacity market models; and (c) external peer review or independent assessment functions.

**Asset or Fleet Valuation in Support of Litigation and Arbitration Proceedings (Multiple Clients).** In litigation and arbitration contexts, provided estimates of economic damages or asset/fleet value estimates that would have applied at the time of a particular business decision. Supported expert testimony, litigation workpapers, and assessment of opposing experts' analysis.

**Economic Analysis of Plant Retrofit and Fuel Contracting Decisions (Multiple Clients).** Supported plant operational and investment decisions for enhancing the value of particular assets, including contexts such as: (a) retrofitting plants from oil to gas generation; (b) retrofitting single-cycle to combined cycle with different capacities for duct firing; (c) enhancing ancillary service capability; and (d) and contracting for firm gas capability. Evaluated operational, cost, and revenue impacts of alternatives and compared to present investment costs.

**Financial Implications of Regulatory, Policy, and Market Design Changes (Multiple Clients).** Conducted analyses of risks and opportunities associated with regulatory, policy, and market design changes. Examples include an analysis of potential Trump administration policies, implications of potential clean energy and carbon policies, and assessing private risks from changes to ancillary service market rules.

## INTEGRATION OS EMERGING TECHNOLOGIES

**Revenue Projections for Storage, Hybrid, Renewable, Demand Response, and Distributed Resource Technologies (Multiple Clients).** For multiple clients across many wholesale electricity markets, conducted projections of net revenues available to assets of many different technology types considering: access to participate in various wholesale electricity products, opportunities to sell environmental attributes or earn policy incentives, and contracted asset revenues. Provided revue projections across alternative market and policy scenarios and alternative asset configurations, in the context of informing investment strategy and investor due diligence. Review policy context and regulatory uncertainties that may enhance or erode market opportunities for particular assets or investment portfolios of emerging resources.

**RTO Business Models Analysis for Enabling Customer-Side Disruption and the Clean Energy Future.** For a system operator, engaged in an executive strategy analysis to evaluate a range of electricity sector business models under a future with high penetrations of distributed resources and decarbonization. Developed detailed scenario descriptions of the business models envisioned considering different roles and scope of services provided by the RTO, distribution companies, load serving entities, and third-party aggregators. Created an interactive tool for mapping financial flows and energy flows at all points in the electricity value chain under each business model considered, and drew implications for value proposition of each segment of the market.

**Enabling Market Participation from Non-Emitting and Emerging Technologies.** For an Ontario stakeholder group, provided expert support to identify market design enhancements to enable and integrate non-emitting and emerging technologies. Examined participation barriers and design enhancements to unlock full value of resources for supporting energy, flexibility, capacity, and other value streams to the province.

**New Jersey Offshore Wind Transmission Solicitation.** For the New Jersey Board of Public Utilities, supporting the competitive solicitation of transmission investments to support the integration of up to 7,500 MW of offshore wind, including solutions for on-shore upgrades, offshore connections, and offshore network options. Economic, environmental, and legal analysis will support Board selection of winning projects under the first-ever PJM State Agreement Approach process for transmission development in support of state policies.

**International Review of Demand Response Integration into Wholesale Electricity Markets.** For the Australian Energy Market Commission, authored a report describing the range of approaches and market experience integrated demand response into wholesale energy, ancillary service, and capacity markets. Provided detailed discussion of approaches in Singapore, Alberta, ERCOT, PJM, ISO New England, and Ontario. Summarized lessons learned regarding demand response business models, efficient wholesale pricing signals, and interactions with retail markets.

**Integration of Energy Efficiency in Capacity Markets.** For Advanced Energy Economy, developed a series of papers focused on best practices for integrating energy efficiency into wholesale capacity markets in a competitive, resource-neutral fashion that enables all business models.

**Integration of Demand Response into Ontario Energy Markets.** For the Ontario market operator, conducted a review of opportunities to better integrate demand response into energy market dispatch, price formation, and settlements. Reviewed interactions amongst capacity, energy, and retail pricing incentives. Authored a recommendations report, evaluated the magnitude of potential consumer benefits, and supported stakeholder engagement.

**Oncor Distributed Storage Business Models to Supply Customer, Distribution System, and Wholesale Value Streams.** For Oncor Electric Delivery Company, conducted a benefit-cost analysis of adding varying levels of distributed storage into the Texas market. Recommended policy changes to enable storage under a range of business models (merchant, utility-owned, customer-owned, and third-party owned), and to allow for the development of resources that could provide multiple value streams. Value streams considered including market values such as energy and ancillary services, distribution-system values including deferred transmission and distribution costs, and customer value streams including avoiding distribution outages. Evaluated value from the perspectives of customers, a merchant storage developer, and society as a whole, as well as evaluating impacts on incumbent suppliers.

**Risk and Financial Analysis of PJM Capacity Performance Product.** For a market participant, conducted a probabilistic assessment of the expected value, upside, and downside risks (both market-wide and private) associated with PJM's capacity performance product. Evaluated the likely frequency of scarcity events on average and as concentrated in particular years to estimate the expected value of bonus payments if operating as an energy-only asset, and the net potential bonus/penalty if operating as a capacity performance resource. Estimated risk-neutral and risk-averse capacity price offer levels; characterized the magnitude of risk exposure of poor asset performance coincided with system scarcity events.

**Capacity Auction Design and Auction Clearing Software Testing**. For a system operator, assisted in the high-level and detailed designs of a capacity auction. Supported market rule development and auction clearing optimization specification. As part of software implementation testing, developed optimization engine in GAMS/CPLEX to replicate auction clearing results, conducted quality control testing of auction clearing engine across 100+ test cases to ensure fidelity and consistency with market rules; conducted software quality control testing across multiple design iterations across several years.

**Hedging Products for Wind.** For a hedge fund, provided analytical support for the development of a hedging product for wind developers. Evaluated the risk exposure based on day-ahead and real-time participation, locational price differentials, profile and curtailment risks, and discrepancies with exchange-traded hedging products.

**Tariff Design for Merchant Transmission Upgrades.** For a transmission developer, evaluated tariff design options for capturing market value of wind and transmission for a market participant proposing a large HVDC upgrade to enable wind developments.

**Magnitude and Potential Impact of "Missing Efficiency" in PJM.** For the Natural Resources Defense Council, analyzed the potential magnitude of energy efficiency programs in PJM that are not accounted for on either demand side (through load forecast adjustments) or on the supply side (in the capacity market). Estimated potential energy and capacity market customer cost impacts in both the short-run and long-run if adjusting the load forecast to account for the missing efficiency.

**Market Reforms to Meet Emerging Flexibility Needs.** For the Natural Resources Defense Council, authored a report on the electricity market reforms needed in the context of declining needs for baseload resources, increasing levels of intermittent supply, and increasing needs for flexible resources.

## Representative Publications

### PAPERS & REPORTS

Sergici, Sanem, Kavlak, Goskin, and Spees, Kathleen. *New Jersey Energy Master Plan: Ratepayer Impact Study.* Prepared for the New Jersey Board of Public Utilities (NJBPU), August 2022

Spees, Kathleen, Newell, Samuel A., Pfeifenberger, Johannes, DeLosa III, Joe. *Illinois Renewable Energy Access Plan.* Prepared for Illinois Commerce Commission, July 2022.

Newell, Samuel A. and Spees, Kathleen. *Capacity Resource Accreditation for New England's Clean Energy Transition.* Prepared for Massachusetts Attorney General's Office, June 2022.

Spees, Kathleen and Newell, Samuel A. *Fifth Review of PJM's Variable Resource Requirement Curve for Planning Years Beginning 2026/27*. Prepared for PJM Interconnection, April 2022.

Spees, Kathleen and Newell, Samuel A. Efficiently Managing Net Load Variability in High-Renewable Systems: Designing Ramping Products to Attract and Leverage Flexible Resources. Presented before the Federal Energy Regulatory Commission, Docket No. AD21-10-000, February 2022.

Spees, Kathleen (with co-authors). *Carbon Trading for New York City's Building Sector: Report of the Local Law 97 Carbon Trading Study Group to the New York City Mayor's Office of Climate and Sustainability*. Prepared with the Guarini Center on Environmental, Energy & Land Use; HR&AA Advisors, Inc.; the Institute for Policy Integrity at the New York University; and the Steven Winter Associates, Inc., November 2021

Spees, Kathleen and Carless, Travis. *Toward 100% Carbon-Free Electricity: How the Regional Electricity Market Can Evolve to Help Washington, DC Achieve Its Energy and Climate Change Goals.* Prepared for the District of Columbia Department of Energy and Environment, October 2021.

Spees, Kathleen, Newell, Samuel A., and DeLosa III, Joe. *Alternative Resource Adequacy Structures for New Jersey.* June 2021.

Pfeifenberger, Johannes and Spees, Kathleen. *The Benefits of Energy Efficiency Participation in Capacity Markets.* Prepared for Advanced Energy Economy, April 2021.

Pfeifenberger, Johannes and Spees, Kathleen. *Enabling Cost-Effective Energy Efficiency in the Midcontinent ISO Resource Adequacy Construct: The advantages of a Supply-Side, Gross Accounting Framework*. Prepared for Advanced Energy Economy, April 2021.

Newell, Samuel A. and Spees, Kathleen. *Alternative Resource Adequacy Structures for New Jersey: Draft Economic Impact Estimates.* Prepared for New Jersey Board of Public Utilities, March 2021.

Carless, Travis, Newell, Samuel A., Spees, Kathleen. *Alternative Resource Adequacy Structures for Maryland: Review of the PJM Capacity Market and Options for Enhancing Alignment with Maryland's Clean Electricity Future.* Prepared for the Maryland Energy Administration, March 2021.

Newell, Samuel A. and Spees, Kathleen. *Qualitative Analysis of Resource Adequacy Structures of New York*. May 2020

Newell, Samuel A. and Spees, Kathleen. *Quantitative Analysis of Resource Adequacy Structures.* Prepared for NYSERDA and NYSDPS, July 2020.

Newell, Samuel A., Pfeifenberger, Johannes, and Spees, Kathleen. *Brattle Economists: Regional Power Market Mechanisms are a Better Path to Meeting Clean-Energy Polices.* Published by The Brattle Group, Inc., June 2020.

Lam, Long, Pfeifenberger, Johannes, and Spees, Kathleen. *Energy Market Payment Options for Demand Response in Ontario.* May 2020

Newell, Samuel A., Pfeifenberger, Johannes, and Spees, Kathleen. *Forward Clean Energy Markets: A New Solution to State-RTO Conflicts.* Published by Utility Dive, January 2020.

Newell, Samuel A. and Spees, Kathleen. *How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes*. Expended Report Including a Detailed Market Design Proposal. Prepared for NRG, September 2019.

Brown, Toby, Newell, Samuel A., and Spees, Kathleen. *International Review of Demand Response Mechanisms in Wholesale Markets.* Prepared for the Australian Energy Market Commission, June 2019.

Hagerty, Michael and Spees, Kathleen. *Demand Curve and Energy and Ancillary Services Offset.* Prepared for Alberta Electric System Operator, April 2019.

Hagerty, Michael, Newell, Samuel A., Pfeifenberger, Johannes, Spees, Kathleen. *Fourth Review of PJM's Variable Resource Requirement Curve.* Prepared for PJM, March 2019.

Brown, Toby, Newell, Samuel A., and Spees, Kathleen. *Near-Term Reliability Auctions in the NEM: Lessons from International Jurisdictions.* Prepared for the Australian Energy Market Operator, March 2019.

Brown, Toby, Neil Lessem, Roger Lueken, Kathleen Spees, and Cathy Wang. *High-Impact, Low-Probability Events and the Framework for Reliability in the National Electricity Market.* Prepared for the Australian Energy Market Commission, February 2019.

Newell, Samuel A., Ariel Kaluzhny, Kathleen Spees, Kevin Carden, Nick Wintermantel, Alex Krasny, and Rebecca Carroll. *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region.* Prepared for the Electric Reliability Council of Texas, Inc. December 20, 2018.

Pfeifenberger, Johannes P., Kathleen Spees, Michael Hagerty, Mike Tolleth, Martha Caulkins, Emily Shorin, Sang H. Gang, Patrick S. Daou, and John Wroble. *AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date.* Prepared for Alberta Electric System Operator. September 4, 2018.

Pfeifenberger, Johannes P., John Tsoukalis, Judy Chang, and Kathleen Spees. *Initial Comments on SPP's Draft Ramp Product Report.* August 30, 2018.

Spees, Kathleen, Johannes P. Pfeifenberger, Samuel A. Newell, and Judy Chang. Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively. July 30, 2018.

Newell, Samuel A., David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin. *Fourth Review of PJM's Variable Resource Requirement Curve.* April 19, 2018.

Newell, Samuel A., Kathleen Spees, Yingxia Yang, Elliott Metzler, and John Imon-Pedtke. *Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM.* April 12, 2018.

Spees, Kathleen, Samuel A Newell, David Luke Oates, Toby Brown, Neil Lessem, Daniel Jang, and John Imon Pedtke. *Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions.* Prepared for the Australian Energy Market Operator, August 23, 2017.

Newell, Samuel A., Roger Lueken, Jürgen Weiss, Kathleen Spees, Pearl Donohoo-Vallett, and Tony Lee. *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals.* Prepared for the New York Independent System Operator. August 10, 2017.

Newell, Samuel A., Johannes P. Pfeifenberger, Judy Chang, and Kathleen Spees. "How Wholesale Power Markets and State Environmental Policies Can Work Together," *Utility Dive,* July 10, 2017.

Chang, Judy, Mariko Geronimo Aydin, Johannes P. Pfeifenberger, Kathleen Spees, and John Imon Pedtke. *Advancing Past "Baseload" to a Flexible Grid: How Grid Planners and Power Markets are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix*. Prepared for the Natural Resources Defense Council. June 26, 2017.

Pfeifenberger, Johannes P., Kathleen Spees, Judy Chang, Walter Graf, and Mariko Geronimo Aydin. "Reforming Ontario's Wholesale Electricity Market: The Costs and Benefits," *Energy Regulation Quarterly,* Volume 5, Issue 2. June 2017.

Spees, Kathleen, Yingxia Yang, and Yeray Perez. *Energy and Ancillary Services Market Reforms in Greece: A Path to Enhancing Flexibility and Adopting the European Target Model.* Prepared for the Hellenic Association of Independent Power Producers (HAIPP). May 2017.

Pfeifenberger, Johannes, Kathleen Spees, Judy Chang, Mariko Geronimo Aydin, Walter Graf Peter Cahill, James Mashal, John Imon Pedtke. *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project.* Prepared on behalf of the Independent Electricity System Operator. Draft Report March 3, 2017.

Chang, Judy, Kathleen Spees, and Tony Lee. *$CO_2$ Allowance Allocation Options: Considerations for Policymakers when Developing Mass-Based Compliance Strategies Under the Clean Power Plan*. Prepared on behalf of the National Resources Defense Council. November 2016.

Chang, Judy, Kathleen Spees, Metin Celebi, and Tony Lee. *Covering New Gas-Fired Combined Cycle Plants under the Clean Power Plan: Implications for Economic Efficiency and Wholesale Electricity Markets*. Prepared on behalf of the Natural Resources Defense Council. November 2016.

Chang, Judy, Kathleen Spees, and Pearl Donohoo-Vallett. *Enabling Canadian Electricity Imports for Clean Power Plan Compliance: Technical Guidance for U.S. State Policymakers.* Prepared on behalf of the Canadian Electricity Association, Canadian Hydropower Association, Canadian Wind Energy Association, Emera Incorporated, Government of Canada, Government of Québec, Manitoba Hydro, Nalcor Energy, and Powerex Corporation. June 2016.

Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, and Roger Lueken. "Open Letter to GAO: Response to U.S. Senators' Capacity Market Questions." Submitted to the U.S. Government Accountability Office. May 5, 2016.

Spees, Kathleen, Samuel A. Newell, and Colin A. McIntyre. *Western Australia's Transition to Competitive Capacity Auction*. Prepared on behalf of EnerNOC. January 29, 2016.

Chupka, Metin Celebi, Judy Chang, Ira H. Shavel, Kathleen Spees, Jürgen Weiss, Pearl Donohoo-Vallett, Michael Hagerty, and Michael A. Kline. *The Clean Power Plan: Focus on Implementation and Compliance.* Published by The Brattle Group, Inc. January 2016.

Newell, Samuel A., Kathleen Spees, and Roger Lueken. Enhancing the Efficiency of Resource Adequacy *Planning and Procurements in the Midcontinent ISO Footprint: Options for MISO, Utilities and States.* Prepared on behalf of NRG. November 2015.

Brown, Toby, Samuel A. Newell, David Luke Oates, and Kathleen Spees. *International Review of Demand Response Mechanisms.* Prepared for the Australian Energy Market Commission. October 2015.

Spees, Kathleen, Judy Chang, Johannes P. Pfeifenberger, Matthew K. Davis, Ioanna Karkatsouli, James Mashal, and Lauren Regan. *The Value of Distributed Electricity Storage in Texas – Proposed Policy for Enabling Grid-Integrated Storage Investments*. Prepared on behalf of Oncor. March 2015.

Spees, Kathleen and Samuel A. Newell. *Resource Adequacy in Western Australia: Alternatives to the Reserve Capacity Mechanism.* Prepared on behalf of EnerNOC. August 2014.

Faruqui, Ahmad, Sanem Sergici, and Kathleen Spees. *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast.* Prepared on behalf of the Sustainable FERC Project. September 2014.

Celebi, Metin, Kathleen Spees, J. Michael Hagerty, Samuel A. Newell, Dean Murphy, Marc Chupka, Jürgen Weiss, Judy Chang, and Ira Shavel. "EPA's Proposed Clean Power Plan: Implications for States and the Electricity Industry," Policy Brief. June 2014.

Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Ann Murray, and Ioanna Karkatsouli. *Third Triennial Review of PJM's Variable Resource Requirement Curve.* May 15, 2014.

Newell, Samuel A., Michael Hagerty, Kathleen Spees, Johannes P. Pfeifenberger, Quincy Liao, Christopher D. Ungate, and John Wroble. *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM.* May 15, 2014.

Newell, Samuel A., Johannes P. Pfeifenberger, and Kathleen Spees. *Estimating the Economically Optimal Reserve Margin in ERCOT.* Prepared for the Public Utility Commission of Texas and the Electric Reliability Council of Texas. January 31, 2014.

Newell, Samuel A., and Kathleen Spees. Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent. January 27, 2014.

Spees, Kathleen, Samuel A. Newell, and Johannes Pfeifenberger. "Capacity Markets: Lessons Learned from the First Decade," published in *Economics of Energy & Environmental Policy.* Vol. 2, No. 2. September 2013.

Pfeifenberger, Johannes, Kathleen Spees, Kevin Carden, and Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications.* Prepared for the Federal Energy Regulatory Commission. September 2013.

Pfeifenberger, Johannes P., Kathleen Spees, and Michael DeLucia. *Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update*, prepared for the Alberta Electric System Operator. March 2013.

Pfeifenberger, Johannes P., Kathleen Spees, and Samuel A. Newell. *Resource Adequacy in California: Options for Improving Efficiency and Effectiveness*. Prepared for Calpine. October 2012.

Newell, Samuel A., Kathleen Spees, Johannes P. Pfeifenberger, Robert S. Mudge, Michael DeLucia, and Robert Carlton. *ERCOT Investment Incentives and Resource Adequacy*. Prepared for the Electric Reliability Council of Texas. June 1, 2012.

Celebi, Metin, Kathleen Spees, Quincy Liao, and Steve Eisenhart. *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS*. Prepared for the Midcontinent Independent System Operator.

Pfeifenberger, Johannes, Kathleen Spees, Attila Hajos, Delphine Hou, and Dan Harris. *Alberta's Intertie Challenges: A Survey of Market Design Options for Seams Between Power Markets*. Prepared for the Alberta Electric System Operator.

Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Attila Hajos, and Kamen Madjarov. *Second Performance Assessment of PJM's Reliability Pricing Model*. Prepared for PJM Interconnection. August 26, 2011.

Spees, Kathleen, Samuel A. Newell, Johannes P. Pfeifenberger, Robert Carlton, and Bin Zhou. *Cost of New Entry Estimates for Combustion Turbine and Combined-Cycle Plants in PJM.* Prepared for PJM Interconnection. August 24, 2011.

Pfeifenberger, Johannes P., and Kathleen Spees. *Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market*. Prepared for the Alberta Electric System Operator. April 2011.

Newell, Samuel A., Kathleen Spees, and Attila Hajos. *Midwest ISO's Resource Adequacy Construct: an Evaluation of Market Design Elements.* Prepared for the Midwest Independent System Operator. January 19, 2010.

Pfeifenberger, Johannes P., Kathleen Spees, and Adam C. Schumacher. *A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs*. Prepared for PJM Interconnection. September 2009.

Spees, Kathleen. "*Meeting Electric Peak on the Demand Side: Wholesale and Retail Market Impacts of Real-Time Pricing and Peak Load Management Policy*," PhD Thesis, Carnegie Mellon University.

Spees, Kathleen with Lester Lave, Jay Apt, and M. Granger Morgan. "Policy Brief on the Smart Metering, Peak Load Reduction, and Efficiency Provisions of House Bills 2200 and 2201." June 13, 2008.

*Technology: Enabling the Transformation of Power Distribution.* Prepared by the Center for the Study of Science, Technology, & Policy (Contributions from Kathleen Spees), and Infosys for the Ministry of Power of India.

Spees, Kathleen. "Real-Time Pricing as an Effective Substitute for Electric Generation Capacity: How Innovative Retail Electric Services Can Benefit the Grid," *Network Industries Quarterly*. Spring 2007.

Spees, Kathleen, and Lester Lave. "Impacts of Responsive Load in PJM: Load Shifting and Real Time Pricing." 2007. *The Energy Journal*. Vol. 29, No. 2. 2008.

Spees, Kathleen, and Lester Lave. "Demand Response and Electricity Market Efficiency." *The Electricity Journal.* Volume 20, Issue 3, April 2007.

Apt, Jay, Seth Blumsack, and Lester B. Lave with contributions from Lee Gresham, Adam Newcomer, Kathleen Spees, and Rahul Walawalkar. *Competitive Energy Options for Pennsylvania*. Carnegie Mellon Electricity Industry Center. January 2007.

Fowler, Kimberly, Amy Solana, and Kathleen Spees. *Building Cost and Performance Metrics: Data Collection Protocol, Revision 1.1*. Prepared by Pacific Northwest National Laboratory for the Federal Energy Management Program, September 2005.

## TESTIMONY

Newell, Samuel A., Kathleen Spees, and David Luke Oates. Response on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution. Docket No. ER17-284-000. January 13, 2017.

Newell, Samuel A., Kathleen Spees, and David Luke Oates. Testimony on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution. Docket No. ER17-284-000. November 1, 2016.

Chang, Judy, Kathleen Spees, and David Luke Oates, Comments on the Clean Power Plan Federal Implementation Plan Proposal Sponsored by Wolverine Power Supply Cooperative, Inc. Before the Environmental Protection Agency, Docket No. EPA-HQ-OAR-2015-0199. January 21, 2016.

Newell, Samuel A. and Kathleen Spees. Affidavit on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve, for Use in PJM's Capacity Market, Before the Federal Energy Regulatory Commission, Docket ER14-2940-000. November 5, 2014.

Newell, Samuel A. and Kathleen Spees. Affidavit on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Before the Federal Energy Regulatory Commission, Docket ER14-2940-000. September 25, 2014.

Newell, Samuel A. and Kathleen Spees. Testimony on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve. Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000. April 1, 2014.

Newell, Samuel A. and Kathleen Spees. Response on Behalf of PJM Interconnection, LLC, Regarding the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model. Before the Federal Energy Regulatory Commission. Docket No. ER12-13-000. January 13, 2012.

Newell, Samuel, Kathleen Spees, and Philip Q. Hanser. Supplemental Comments, Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets. Before the Federal Energy Regulatory Commission. October 4, 2010. Docket Nos. RM10-17-000 and EL09-68-00.

Pfeifenberger, Johannes P. and Kathleen Spees. Comments In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results. Before the State of Maryland Public Service Commission. Administrative Docket PC22. Filed October 1, 2010.

Newell, Samuel, Kathleen Spees, and Philip Q. Hanser. Comments, Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets. Before the Federal Energy Regulatory Commission. May 13, 2010. Docket Nos. RM10-17-000 and EL09-68-00.

## PRESENTATIONS

Spees, Kathleen. "Locational Marginal Emissions: Opportunities to Improve Cost-Effective Clean Energy Transition with Granular Greenhouse Gas Emissions Data." Presented at the New England Electricity Restructuring Roundtable, December 2022.

Spees, Kathleen and O'Loughlin, Matthew. "Stranded Fossil Fuel Infrastructure: How Big is the Stranded Asset Problem and What Should We Do About it?" Presented to American Gas Association FERC Regulatory Committee, June 2021.

Spees, Kathleen. "The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition." Presented to New England Power Pool, October 2020.

Spees, Kathleen. "Enabling Canadian Imports for Advancing Clean Energy Strategies for the US – Considerations for Policymakers." Prepared for the Canadian Electricity Association and Canadian Embassy Event, July 2020.

Spees, Kathleen. "The Next Generation of Energy Resource Planning." Presented at National Conference of State Legislatures 2019 Legislative Summit, August 2019.

Spees, Kathleen and Matthew Witkin. "Market Design for a Clean Grid: Unlocking the Potential for Non-Emitting and Emerging Technologies," Presented to IESO Non-Emitting Resource Subcommittee. January 22, 2018.

Spees, Kathleen. "Clean Energy Markets: The 'Missing Link' to Market Design 3.0." Presented to the Harvard Electricity Policy Group. October 4, 2018.

Spees, Kathleen. "The Cutting Edge in Resource Planning." Presented to the Solar Energy Industries Association. November 12, 2018.

Spees, Kathleen. "An Economic Perspective on Reliability: Rethinking System Needs and in a Future Dominated by Renewables, New Tech, and Engaged Consumers." Presented at the Electricity Consumers Resource Council. November 28, 2018.

Spees, Kathleen, Judy Chang, and David Luke Oates. "A Dynamic Clean Energy Market in New England," November 2017. Prepared for Conservation Law Foundation, Brookfield Renewable, NextEra Energy Resources, and National Grid.

Chang, Judy, Spee, Kathleen, and Pfeifenberger, Johannes. "Hello World: Alberta's Capacity Market." Presented at the 2018 IPPSA Conference. November 2017.

Spees, Kathleen. "Decarbonisation and Tomorrow's Electricity Market," Presented at the 2017 IESO Stakeholder Summit. June 12, 2017.

Spees, Kathleen, Johannes P. Pfeifenberger, Judy Chang, Yingxia Yang, Rebecca Carroll, Roger Lueken, and Colin McIntyre. "Flexibility Enhancements: Alberta Needs and Experience from Other Jurisdictions," Prepared for the Alberta Electricity System Operator," August 10, 2017.

Spees, Kathleen. "Rethinking Capacity Mechanisms in the Context of Emerging Flexibility Challenges," Presented at the European Capacity Mechanisms Forum. February 3, 2017.

Spees, Kathleen. "$CO_2$e Cap-and-Trade: Interactions with Electricity Markets," Presented to the Associated of Power Producers of Ontario. November 15, 2016.

Spees, Kathleen, Samuel A. Newell, and Judy Chang. "Using Competitive Markets to Achieve Policy Objectives: How the Systems Built for Fossil Plants Can Evolve to Support the Clean, Distributed Grid of the Future." Presented at the Energy Bar Association 2017 Annual Meeting & Conference. March 29, 2017.

Chang, Judy, Kathleen Spees, and Pearl Donohoo-Vallett. "Enabling Canadian Imports for Advancing Clean Energy Strategies for the U.S.: Considerations for Policymakers," Presented at the Embassy of Canada and Canadian Electricity Association's Half-day Conference. October 24, 2016.

Spees, Kathleen, Samuel A. Newell, David Luke Oates and James Mashal. "Clean Power Plan in Texas: Implications for Renewables and the Electricity Market," Presented at the 2016 Renewable Energy Law Conference. February 9, 2016.

Pfeifenberger, Johannes P., Judy Chang, Kathleen Spees, and Matthew K. Davis. "Impacts of Distributed Storage on Electricity Markets, Utility Operations, and Customers," 2015 MIT Energy Initiative Associate Member Symposium. May 1, 2015.

Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," Energy Storage Policy Forum 2015, Washington, D.C. January 29, 2015.

Spees, Kathleen. "EPA's Clean Power Plan: Potential Impacts on Asset Values," Infocast 7th Annual Projects & Money Summit 2015. January 13, 2015.

Graves, Frank, and Kathleen Spees. "How will the EPA's Clean Power Plan Impact Renewables?" *North American Windpower.* July 2014.

Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," UBS Investment Research Webinar. December 5, 2014.

Spees, Kathleen and Judy Chang. "Evaluating Cooperation Opportunities under CAA 111(d)," Presented to the Eastern Interconnection States' Planning Council. October 2, 2015.

Spees, Kathleen. "Implications of EPA's Clean Power Plan under Clean Air Act Section 111(d)," Presented to the Department of Engineering and Public Policy at Carnegie Mellon University. September 18, 2015.

Spees, Kathleen, Samuel A. Newell, and Johannes P. Pfeifenberger. "ERCOT's Optimal Reserve Margin: As Estimated for the Public Utility Commission of Texas and the Electric Reliability Council of Texas," presented to the 2014 Texas Industrial Energy Consumers Annual Meeting. July 15, 2014.

Pfeifenberger, Johannes P., Samuel A. Newell, and Kathleen Spees. “Energy and Capacity Markets: Tradeoffs in Reliability, Costs, and Risks,” presented at the Harvard Electricity Policy Group Seventy-Fourth Plenary Session. February 27, 2014.

Spees, Kathleen, Johannes P. Pfeifenberger, and Samuel A. Newell. “ERCOT’s Optimal Reserve Margin,” presented to UBS Investment Research investor conference call. February 19, 2014.

Spees, Kathleen. “Capacity Markets: Lessons Learned from the First Decade,” presented to EUCI 10th Annual Capacity Markets Conference. November 7, 2013.

Pfeifenberger, Johannes P, and Kathleen Spees. “Characteristics of Successful Capacity Markets,” presented at the APEx Conference 2013, New York. NY. October 31, 2013.

Spees, Kathleen and Johannes Pfeifenberger. “Outlook on Fundamentals in PJM’s Energy and Capacity Markets,” presented at the 12th Annual Power and Utility Conference, Hosted by Goldman Sachs. August 8, 2013.

Newell, Samuel A., and Kathleen Spees. “Get Ready for Much Spikier Energy Prices: The Under-Appreciated Market Impacts of Displacing Generation with Demand Response,” presented at the Cadwalader Energy Investor Conference. February 7, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. “PJM Reliability Pricing Model: 2016/17 Planning Period Parameters Update,” presented to Barclays North American Utilities Investor Call. February 4, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. “Seams Inefficiencies: Problems and Solutions at Energy Market Borders,” presented at the EUCI Canadian Transmission Summit. July 17, 2012.

Spees, Kathleen. “New U.S. Emission Regulations: Electric Industry Impacts,” presented at the U.S. Energy 24th Annual Energy Conference. May 11, 2012.

Spees, Kathleen. “Market Design from a Practitioner’s Viewpoint: Wholesale Electric Market Design for Resource Adequacy,” presented at Lawrence University Economics Colloquium. April 23, 2012.

Spees, Kathleen. “Options for Extending Forward certainty in Capacity Markets.” Presented at the EUCI Conference on Capacity Markets: Achieving Market Price Equilibrium. November 9, 2011.

Spees, Kathleen, and Pfeifenberger, Johannes P. “Resource Adequacy: Current Issues in North American Power Markets.” Presented at the Alberta Power Summit. November 19, 2011.

Spees, Kathleen and Samuel Newell. “Capacity Market Designs: Focus on CAISO, NYISO, PJM, and ISO-NE,” Presented to the Midwest ISO Supply Adequacy Working Group. July 19, 2010.

Pfeifenberger, Johannes P., and Kathleen Spees. “Best Practices in Resource Adequacy,” presented at the PJM Long Term Capacity Issues Symposium. January 27, 2010.

Chang, Judy, Kathleen Spees, and Jurgen Weiss. “Using Storage to Capture Renewables: Does Size Matter?” working paper presented at the 15th Annual POWER Research Conference. University of California Energy Institute’s Center for the Study of Energy Markets. March 18, 2010.