Appendix A

Curriculum Vitae of
R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

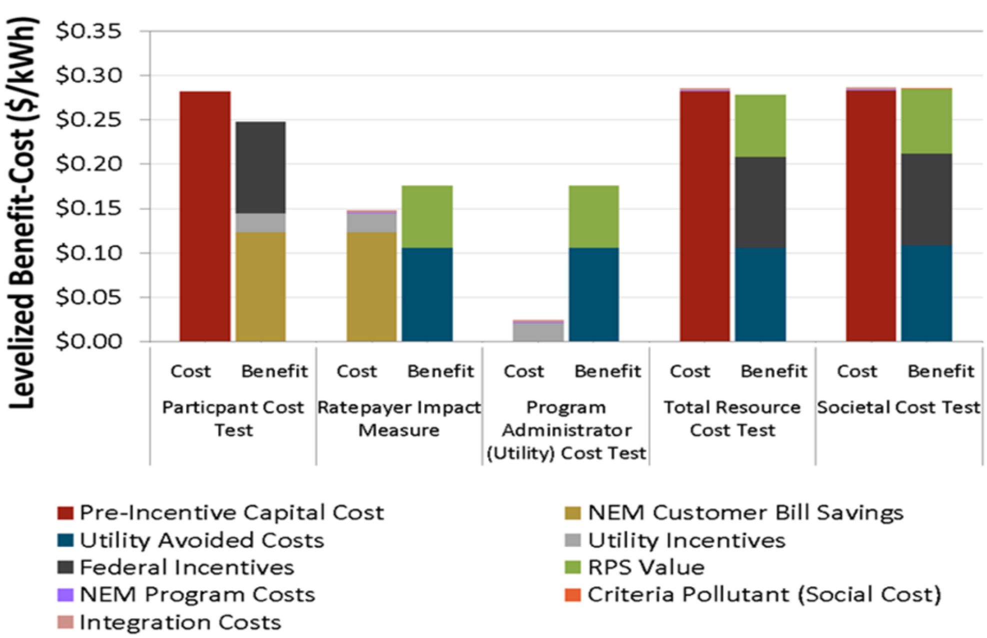
Appendix B

EXPERIENCE IN OTHER STATES:
NEVADA, CALIFORNIA, AND MISSISSIPPI

1. Nevada

The Public Utilities Commission of Nevada ("PUCN") adopted a multi-perspective approach to the benefits and costs of net metering in the study which it released on July 1, 2014.[1] The consulting firm Energy and Environmental Economics (E3) performed the analytic work for this study, and I served on a Stakeholder Committee that the PUCN convened to provide input on the study methodology and analysis. **Figure B-1** below shows the costs and benefits of net-metering for solar PV systems in Nevada going forward, in the years 2014-2016, from each of the key stakeholders' perspectives.[2]

Figure B-1: *Public Utilities Commission of Nevada NEM Benefit-Cost Results*



[1] The PUCN's net metering study, including the spreadsheet models used in the study, can be found at: http://puc.nv.gov/About/Media_Outreach/Announcements/Announcements/7/2014_-_Net_Metering_Study/ .

[2] This figure is from the "Results" tab of the "Nevada Public Tool" model, with the model set to produce results for solar PV and for the going-forward period of 2014-2016.

Notably, the Nevada study showed that NEM is cost-effective for non-participating ratepayers (*i.e.*, the benefits in the RIM test exceeded the costs), while the costs are somewhat higher than the benefits for participants (*i.e.*, for solar customers). As with any such set of cost-effectiveness tests, it is not reasonable or practical to expect each of these tests to achieve a precise 1.0 benefit/cost ratio. Instead, the goal should be to achieve a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers, and the utility system as a whole. In my judgment, the Nevada study demonstrated that NEM at the full retail rate, without any further rate design modifications, achieved that desired "rough justice" balance of interests in Nevada.

The Nevada Commission subsequently moved away from the use of a long-term benefit-cost approach to analyze NEM in that state. In 2015, in response to new legislation, the PUCN reviewed a study from NV Energy that was limited to the short-term cost of service for residential and small commercial customers who install solar DG. The PUCN's subsequent decision on December 23, 2015 accepted the results of that study, and, based on that evidence, found that there was a significant cost shift from non-participating ratepayers to solar DG customers. As a result, the PUCN ended NEM in Nevada, increased the fixed monthly customer charge for DG customers, and reduced the export rate credited to DG systems from the full retail rate (about 11 cents per kWh for residential customers) to an energy-only avoided cost rate of 2.6 cents per kWh. The PUCN took this action even though its order found that there are the following 11 components to the net benefits of DG (based on an adopted stipulation on NEM issues from South Carolina), and that it was only able to quantify the first two components of DG value in the adopted 2.6 cents per kWh export rate:

1. Avoided energy costs
2. Line losses
3. Avoided capacity
4. Ancillary services
5. Transmission and distribution capacity

6. Avoided criteria pollutants
7. Avoided CO_2 emission costs
8. Fuel hedging
9. Utility integration and interconnection costs
10. Utility administration costs
11. Environmental costs[3]

The impacts of the December 2015 decision have been devastating for the solar DG market in Nevada. The reduction in the export rate and the increased fixed charge have reduced the bill savings available to NEM customers in Nevada by 40% or more. Solar DG is no longer economic for new systems. This is the case today, even though the PUCN, most recently, has grandfathered the 32,000 existing NEM customers under the prior NEM rules with a full retail rate credit for exported power.[4] In sum, the elimination of NEM and, in particular, the reduction in the export rate, has decimated the rooftop solar market in Nevada, resulting in more than 1,000 documented layoffs at solar companies.[5]

2. California

The investor-owned utilities in California have reached or are approaching that state's 5% cap on NEM systems. In 2015, the California Commission asked parties to analyze their proposals for a NEM successor tariff using a common "Public Tool" spreadsheet program similar to the Nevada NEM benefit-cost model. Like the Nevada model, the California Public Tool analyzes a proposed tariff from multiple perspectives, using all of the *SPM* cost-effectiveness tests and looking at the long-term, life-cycle costs and benefits. The CPUC received detailed analyses of NEM benefits and costs using the Public Tool from a variety of parties. In January 2016, the California commission decided to extend NEM in California until a further review in 2019, with certain changes such as requiring NEM customers to be on TOU rates, removing certain public benefit charges

3 See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at pp. 66-67 and 95-96.
4 See PUCN September 16, 2016 Order in Dockets Nos. 16-07-028 and 16-07-029.
5 See *Prepared Direct and Rebuttal Testimonies of R. Thomas Beach on behalf of TASC*, served February 1 and 5, 2016 in PUCN Dockets Nos. 15-07-041 and 15-07-042.

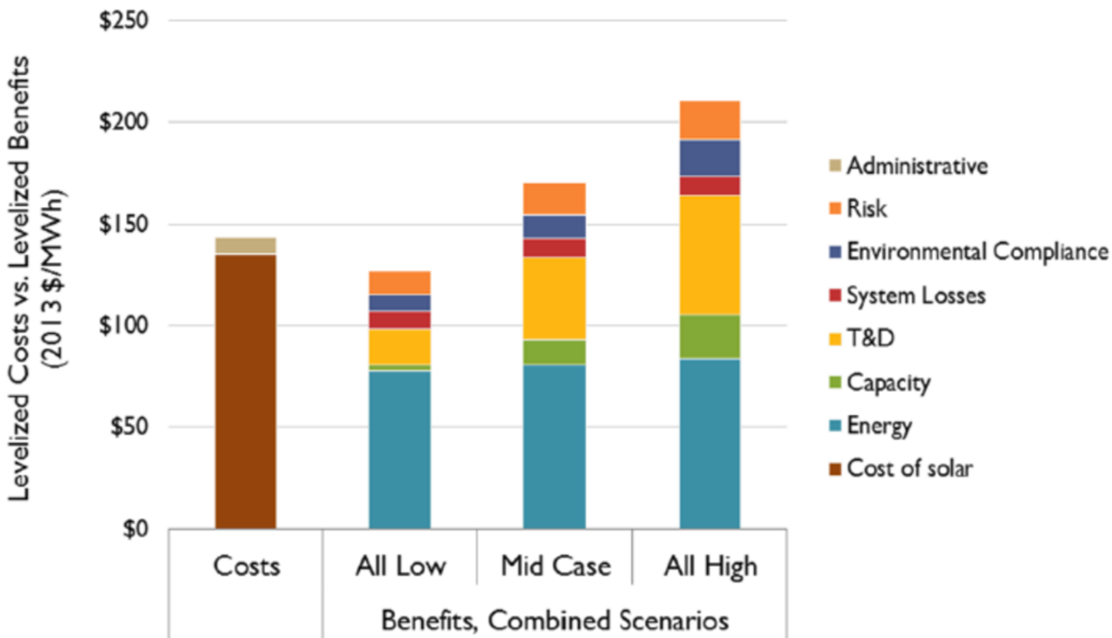
from export rates, and requiring NEM customers to pay interconnection costs. The CPUC's order does not rely on the Public Tool analyses, because important information related to both costs (rate design changes) and benefits (locational benefits on the distribution grid and societal benefits) remain under development in other CPUC proceedings. However, the CPUC made clear that it intends to continue to refine and to use this SPM-based, long-term benefit-cost approach in its future evaluations of NEM and DG.[6]

3. Mississippi

The Public Service Commission of Mississippi completed a NEM benefit/cost analysis in 2014, and NEM is being implemented for the first time in Mississippi.[7] As in the Nevada NEM study, the Mississippi study considered the three principal perspectives discussed above, with a focus on the TRC test because that test best captures the benefits and cost for the state as a whole from this new resource. The Mississippi study also used a 25-year time horizon. The following figure summarizes the mid-case costs and benefits from Mississippi's TRC analysis, plus the maximum low and high sensitivity cases for the benefits.

[6] See CPUC Decision 16-01-044, at pp. 48-50, 54-61, and 80-82.
[7] Elizabeth A. Stanton, *et al*., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* (Synapse Energy Economics for the Public Service Commission of Mississippi, released September 19, 2014); hereafter "Mississippi Study." Available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

Figure B-2: *Public Service Commission of Mississippi NEM Study Results*



As a result of this analysis, the Mississippi study concluded that net metered solar projects will provide a net benefit to Mississippi in almost all of the cases considered. However, the study's analysis of the Participant cost test expressed concern that NEM bill savings at the retail rate will not provide adequate benefits to drive significant adoption of solar DG in the state. As a result, the study suggested that solar customers should be compensated at a rate higher than retail rates. This higher rate would be based on the utilities' avoided cost benefits, so that it would not shift costs to non-participants.[8] Finally, the Mississippi Study criticized the use of the traditional RIM test, particularly in the context of a new NEM program. The problem with the RIM test is that the cost shift measured by the RIM test is simply a re-allocation of costs which the utilities have already incurred and which are not incremental costs resulting from the NEM program. Due to this limitation, the study concluded that RIM test should not be used to judge the merits of the new NEM program.[9]

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[8] Mississippi Study, at pp. 49-50.
[9] *Ibid.*, at pp. 41-43 and Figure 18.

Appendix C

DE 16-576 Outline of Costs & Benefits of NM Systems and Related Variables and Rate Components to be Considered

The New Hampshire Sustainable Energy Association is providing the following list of proposed costs and benefits of net metering systems in order to foster a conversation at the next technical session. The provision of this list should not be construed as a waiver of or act to foreclose NHSEA's ability to address different or additional costs and benefits in this docket.

I. Avoided Energy Supply Costs and Related Benefits
(See Puc 903.02 as a starting point)

a. Generation LMP, simple average vs. time weighted (RTP)
b. Ancillary Charges related to and linked to LMP charges
   i. Ancillary Markets (i.e. Regulation Market, Forward Reserve Mark et, Real-Time
      Reserve Market, Transitional Demand Response Program)
   ii. Net Commitment-Period Compensation, 1st & 2nd contingency
   iii. Miscellaneous Credits/Charges (i.e. Inadvertent Energy, Marginal Loss Revenue Fund, Financial Transmission Rights (FTR) Auction Revenue Rights)
   iv. Wholesale Market Service Charge (i.e. ISO Tariff Schedule 2 and 3 Expenses, NEPOOL Expenses)
c. Capacity Avoided Costs (FCM charges)
d. Line Loss Factors
e. One size fits all for NEM systems vs. distinguishing between solar and other DG
f. Applicable intervals
g. DRIPE (Demand Reduction Induced Price Effect) i.e.. - Energy market effects; less energy purchases lowers market clearing prices, lower wholesale demand lowers FCM clearing price
   i. Energy
   ii. Capacity
h. Supply diversity and hedging benefits

II. Avoided Transmission Costs

a. Regional Network Service (PTF or pooled transmission facilities)
b. Local Network Service (non-PTF)
c. Line Loss Factors

III. Avoided & Incurred Distribution Costs & Benefits

a. Costs to Distribution grid, actual & potential
    i. Cost to installers for interconnection
    ii. Utility costs to process & integrate DER beyond those paid by installers
    iii. Administrative & billing costs
    iv. Other costs
b. Benefits to Distribution grid, actual & potential
    i. Avoided new capacity investments (NWA - non wires alternatives)
    ii. Equipment life extension
    iii. Voltage and power quality support
    iv. Other distribution benefits
c. Locational Aspects
d. Rate Design questions, fixed and variable components, demand charges, interval and flows for determining charges

IV. **Renewable Energy Credits (RECs), RPS Compliance and other miscellaneous charges** (SBC, SCRC, Electricity Consumption Tax)

V. **Avoided Environmental Costs or Derived Benefits**
a. NOx and CO2 compliance costs
b. Net social costs NOx, SO2, CO2, other pollutants (environmental externalities beyond compliance costs)
c. Other

VI. **Other Non-energy Benefits**
(e.g. economic development, job creation, tax revenue)

VII. **Overarching** – use of modeled vs. actual PV and other NEM hourly data

VIII. **Utility Recovery of Lost Distribution Revenue**
a. Behind the meter consumption
b. Bill credits for all exports

IX. **Any size & eligibility limits**

a. Need there be any limits on DG capacity due to reliability or other engineering concerns? If so, how and when determined?
b. Is there any basis or good reason to have any other size or eligibility limits on tariffs.

X. **Other market segmentation**

Appendix D

The Benefits and Costs of Distributed Solar Generation in New Hampshire

This appendix presents a benefit-cost analysis of the impacts of distributed solar generation ("solar DG") on ratepayers in the service territories of the three investor-owned utilities in New Hampshire – Eversource, Liberty, and Unitil. This work considers the benefits and costs of solar DG from the perspectives of all of the key stakeholders – solar DG customers, other ratepayers, and the system and society as a whole – who together constitute the public interest in the development of DG resources in New Hampshire. To consider all of these perspectives, we examine the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources that commonly are used in the utility industry. We use a long-term, life-cycle analysis that covers the useful life of a solar DG system (25 years). This evaluates the benefits and costs of solar DG on the same basis as other utility resources on both the demand- and supply-sides.

The cost-effectiveness tests for demand-side resources use benefits and costs that we calculate using three principal analyses:

- An analysis of the **direct ratepayer benefits** of solar DG, in terms of the costs that the utilities will avoid as a result of solar DG development. These benefits are used in the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") tests. In the Societal test, these direct benefits are supplemented by additional **societal benefits** that accrue to society as a whole.

- A calculation of the life-cycle **costs of installing and operating** solar DG systems, used in the Participant and TRC tests.

- Analysis of the **bill savings** which participating customers realize from their solar DG installations. This is the principal benefit for these customers in the Participant test. The bill savings are also **lost revenues** for the utility, which constitute the principal costs for non-participating ratepayers in the RIM test.

This report presents and discusses each of these analyses, for the three utilities.

1. Benefits of Solar DG

a. Avoided energy costs.

We calculate avoided energy costs based on ISO New England ("ISO-NE") locational marginal price ("LMP") data for New Hampshire. We calculate a PV-weighted average of hourly day-ahead LMP prices for the year ending in the third quarter (3Q) of 2016 equal to about $32 per MWh, with small differences among the three utilities based on slightly different solar output profiles.[1] This 2015-2016 energy price is then escalated to future years using a long-term forecast of natural gas market prices that is based, for the initial twelve years, on natural gas forward prices in the benchmark Henry Hub market and, in subsequent years, on the escalation in natural gas prices at the Henry Hub in the forecast in the Energy Information Administration's ("EIA") *Annual Energy Outlook 2016*, released in September 2016. This is the same approach used in the Maine Public Utilities Commission's March 2015 *Maine Distributed Solar Valuation Study (Maine Study).*[2] We separately escalate the portion of LMP prices that recovers allowance costs in the New England carbon market (the Regional Greenhouse Gas Initiative ["RGGI"]), based on our forecast of RGGI prices that is discussed in Section 1h below. We levelize the resulting 25-year forecast of solar-weighted LMPs using each utility's weighted average cost of capital ("WACC") as the discount rate. These levelized avoided energy costs are about $63 per MWh after adjusting for the utility-specific distribution line losses that the utilities provided in discovery.

Table D-1: *Avoided Energy Cost (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Levelized LMP	58.79	58.91	58.48
Line Losses	7.75%	6.90%	6.47%
Avoided Energy Cost Including Line Losses ($/MWh)	63.35	62.98	62.27

b. Avoided generation capacity costs

Our projection of avoided generation capacity costs is based on results from ISO-NE's forward capacity market ("FCM") Auctions 9 and 10,[3] plus the projection for future avoided capacity costs included in the most recent regional forecast of avoided costs used for demand-side programs, *Avoided Energy Supply Costs in New England: 2015 Report*

[1] We used the National Renewable Energy Laboratory's ("NREL") Solar Advisor Model ("SAM") to calculate the output of representative solar PV systems in Manchester (Eversource), Concord (Unitil) and Lebanon (Liberty).

[2] Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015), hereafter "Maine Study." Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

[3] See http://www.iso-ne.com/static-assets/documents/2016/02/fca_10_result_report.pdf.

(2015 AESC).[4] Based on this forecast of annual capacity values in the New England market, we determine a levelized capacity price ($/kW-year) for each of the three utilities, again using the current WACC as the discount rate. We then convert this levelized price to an energy price equivalent (in $/MWh) by dividing by expected annual solar production.

To determine the amount of capacity that a solar project provides, we perform a load match analysis that looks at the median of hourly PV capacity factors during the top 100 annual load hours in the New Hampshire zone on the ISO-NE system.[5] We conduct this analysis using hourly loads in three years (2011, 2012, and 2013) and average the annual results. In this analysis, we used actual solar insolation data from 2011-2013 to calculate PV system output using SAM, in order to obtain a more accurate correlation between solar output and actual utility loads in these years.[6] In other words, using actual loads and solar insolation recognizes that hot, sunny, summer days when electric loads are high also tend to be days with high PV output. If typical meteorological year (TMY) data were used for solar output, this correlation would be lost. In fact, the load match factors would be over 20% lower using TMY data for solar output.

Table D-2: *Avoided Generation Capacity Costs (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Levelized Net CONE ($/kW-year)	165.21	163.77	162.12
÷ Solar Output (kWh per kW-AC)	1,324	1,274	1,424
= Generation Capacity Cost ($/MWh)	124.87	128.52	113.83
x PV Load Match (%)	48.8%	40.2%	50.9%
+ Line Losses (%)	7.75%	6.90%	6.47%
= Avoided Generation Capacity ($/MWh)	65.62	55.26	61.66

We estimate that an additional capacity reserve margin of 14.3% is needed to capture the long-term resource adequacy requirements in New England. The ISO-NE uses an indicative 14.3% reserve margin for future years in its *2015 Regional System Plan.*[7] As a result of this reserve capacity requirement, generating capacity must be purchased to cover 114.3% of peak loads to provide the reserve margin necessary to ensure system reliability given contingencies and variations in peak loads.

[4] See *2015 AESC*, at Appendix B., Tables One and Two for New Hampshire. This report is available at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf.
[5] See *Maine Study*,at pp. 24-25.
[6] New Hampshire solar insolation in 2011-2013 is taken from Clean Power Research's *Solar Anywhere* database.
[7] See ISO-NE, *2015 Regional System Plan*, at pp. 65 and 67.

Table D-3: *Avoided Generation Capacity Reserves (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Avoided Generation Capacity ($/MWh)	65.62	55.26	61.66
x Planning Reserve Margin (%)	14.3%	14.3%	14.3%
= Avoided Generation Capacity Reserve ($/MWh)	9.38	7.90	8.82

c. Avoided transmission capacity costs

The majority of the output of solar DG serves on-site loads and never touches the grid, and thus clearly reduces loads on the transmission system. For the minority of power that a solar DG unit exports to the grid, these exports are likely to be entirely consumed on the distribution system by the solar customer's neighbors, unless solar penetration is very high. Thus, like energy-efficiency and demand response resources, solar DG reduces load growth and displaces traditional generation sources that must use the utility transmission system to be delivered to customers. As a result, solar DG will avoid transmission capacity costs to the extent that solar production occurs during the peak demand periods that drive transmission costs.

We calculate avoided transmission costs using ISO-NE's Regional Network Load (RNL) transmission costs for New Hampshire, for the year ending May 2016.[8] There was a significant increase in these costs which took effect on June 1, 2015. We escalate these costs based on the forecast of these costs that is included in the ISO-NE *2015 Regional System Plan*,[9] then at a 2% annual inflation rate thereafter, and levelize them using the utility WACCs. Because ISO-NE allocates these costs based on monthly peak loads, the PV Load Match factor is calculated as the average reduction in each utility's 12 monthly coincident peak demands ("12 CP") due to PV output, per kW of PV nameplate capacity. Again, this set of load match factors is also computed using actual 2011-2013 loads and solar insolation.

We have not developed marginal costs for transmission facilities that the New Hampshire utilities operate that are not part of the ISO-NE regional network, so these avoided transmission capacity costs may be conservative.

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[8] See ISO-NE, *Monthly Regional Network Load Cost Report* (July 2016), at Table 8-1. Available at http://www.iso-ne.com/markets-operations/market-performance/load-costs.
[9] ISO-NE, *2015 Regional System Plan*, at p. 111 (Table 6-2).

Table D-4: *Avoided ISO-NE Transmission Costs (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
RNL Transmission Costs ($/kW-year)	105	105	105
RNL Transmission Costs – NH ($/kW-year) – *25-year levelized*	136.67	136.15	135.56
÷ Solar Output (kWh per kW-AC)	1,324	1,274	1,424
= Transmission Capacity Cost ($/MWh)	103.21	106.84	95.19
x PV Load Match using 12 CP (%)	17.6%	14.9%	17.1%
+ Line Losses (%)	7.75%	6.90%	6.47%
= Avoided ISO-NE Transmission Capacity ($/MWh)	19.58	17.06	17.28

d. Market price response (DRIPE)

We have incorporated data from the *2013 and 2015 AESC* reports on the market price reductions that will result from the on-site solar distributed generation in New Hampshire that serves load directly. This market benefit is also known as the demand reduction induced price effect, or DRIPE. There is a significant difference in the DRIPE impacts in New Hampshire between the *2013* and *2015 AESC* reports, as a result of significant changes in the methodology for the DRIPE calculations in the *2015 AESC*.[10] For example, the *2015 AESC* assumes (1) a much shorter duration for energy DRIPE impacts (three years) and (2) zero capacity DRIPE as a result of an assumed near-term need for new capacity in New England. We have not attempted to resolve these differences, but have used the average of the DRIPE impacts between the two studies. For capacity DRIPE, we use the *2015 AESC* assumption of zero capacity DRIPE as it is consistent with our avoided capacity cost forecast.

Table D-5: *DRIPE (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Levelized LMP	63.35	62.98	62.27
DRIPE Benefit (% of LMP)	4.14%	4.30%	4.46%
+ Line Losses (%)	7.75%	6.90%	6.47%
DRIPE Benefit ($/MWh)	2.82	2.89	2.96

[10] See *2015 AESC*, at pages 1-5 and 1-16 to 1-17.

e. Avoided fuel price uncertainty

Solar DG displaces natural gas, and thus reduces the exposure of New Hampshire ratepayers to the future uncertainty and volatility in natural gas prices. To calculate this benefit, we follow the methodology used in the *Maine Study*. This approach recognizes that one could contract for future natural gas supplies today, and then set aside the money to buy that gas in the future in risk-free investments. This would eliminate the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on an "as you go" basis (and using the money saved for alternative investments) is the benefit of reducing the uncertainty in the costs for the fuel that solar DG displaces.

Table D-6: *Avoided Fuel Price Uncertainty (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Avoided Fuel Price Uncertainty ($/MWh)	25.45	27.44	29.75
+ Line Losses (%)	7.75%	6.90%	6.47%
Avoided Fuel Price Uncertainty ($/MWh)	27.43	29.33	31.67

f. Avoided distribution capacity costs

Distributed solar generation can reduce peak loads on distribution circuits, and thus avoid or delay the need to upgrade or re-configure the circuit if it is approaching capacity. The majority of solar DG output serves the on-site load and will never flow onto the distribution system, and thus reduces the loads served from the local distribution system. In addition, exports from solar DG to the distribution system serve local loads, and thus unload upstream portions of the distribution system. Over the 25-year life of DG systems, these load reductions will avoid or defer distribution system expansions or upgrades and extend the life of existing equipment.

The extent to which solar generation avoids distribution capacity costs is a more complex question than for transmission. Distribution substations and circuits can peak at different times than the system as a whole, which complicates the calculation of by how much solar DG can reduce distribution loads and avoid distribution capacity costs. As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loads, utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid distribution capacity costs.[11] A comparable evolution has occurred over the last several decades, as the long-term

[11] Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid additional costs than those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction. For these reasons, the existing estimates of marginal distribution costs should be considered conservative.

impacts of energy efficiency and demand response programs are now incorporated into utilities' capacity expansion plans, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed are difficult to predict.

Our calculation of avoided distribution capacity costs begins with the utilities' marginal distribution costs. We use the marginal distribution capacity costs which Liberty and Unitil recently filed at the Commission; these marginal costs are based on regression analyses of the relationship between distribution capital additions and load growth. We performed a similar regression analysis for Eversource, which does not have a recent marginal cost study, using FERC Form 1 data.

We then allocate these marginal distribution costs to the high-demand hours of the year using an allocation based on a set of hourly "peak capacity allocation factors" ("PCAFs") derived from 2015 hourly data on distribution substation loads for each utility.[12] The PCAFs are based on hourly substation loads that are within 10% of the annual peak load at each substation, using this formula:

$$PCAF_s(h) = \frac{(Load_s(h) - Threshold_s)}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

where:

$PCAF_s(h)$ = peak capacity allocation factor for substation *s* in hour *h*,
$Load_s(h)$ = the load for substation *s* in hour *h*, and
$Threshold_s$ = 90% of the substation *s* annual peak load.

All hours where the substation load is below 90% of the annual peak are excluded from the calculation of hourly PCAFs. The resulting hourly profile of PCAFs across all of the utility's substations is used to allocate the utility's marginal distribution capacity costs to each hour. Finally, these hourly avoided distribution costs are applied to the hourly output profile of solar DG to calculate avoided distribution capacity costs. This step is shown graphically in **Figure D-1**. The resulting avoided distribution capacity costs are presented in **Table D-7**. The solar- and PCAF-weighted avoided distribution

[12] This approach has been used in the "Public Tool" benefit/cost model of renewable DG developed by Energy and Environmental Economics (E3) for the California Public Utilities Commission ("CPUC"), and used to determine avoided sub-transmission and distribution capacity costs for the California electric utilities. The CPUC's Public Tool model and the association documentation are available at http://www.cpuc.ca.gov/general.aspx?id=3934. The marginal subtransmission and distribution costs are shown in Lines 323-350 of the "Avoided Cost Calcs" tab; the PCAF allocation factors by TOU period are listed in Lines 352-371 of the same tab. The PCAF method also has been used in Colorado. See Crossborder Energy, *Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado: A Critique of PSCo's Distributed Solar Generation Study* at pp. 9-11 (December 2, 2013). This study was filed in Colorado Public Utilities Commission Docket No. 13A-0836E on behalf of TASC.

costs, divided by total marginal distribution costs, yield an aggregate PV load match factor at the distribution level, which is also shown in Table D-7.

Figure D-1: Eversource Substation PCAFs and DG Output

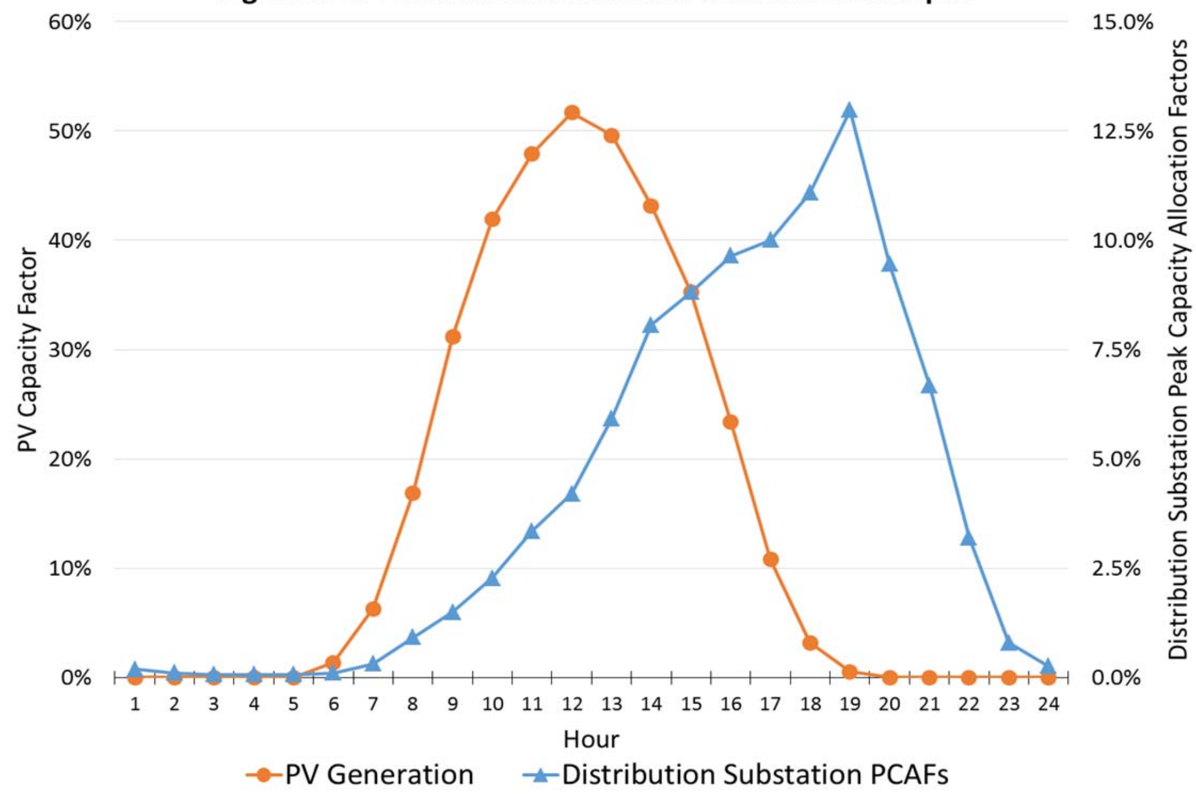

Table D-7: *Avoided Distribution Capacity Costs (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Marginal Distribution Costs ($/kW-year)	133.14	127.61	91.26
÷ Solar Output (kWh per kW-AC)	1,324	1,274	1,424
= Distribution Capacity Cost ($/MWh)	100.55	100.14	64.08
x Effective PV Load Match using Distribution Substation PCAFs (%)	22.3%	29.3%	25.8%
= Avoided Distribution Capacity ($/MWh)	22.46	29.36	16.55

g. Integration and program administration costs

Next, we subtract certain costs from the benefits. First, we subtract an estimate of solar integration costs of $2 per MWh, based on costs from the New England Wind Integration Study.[13] Finally, we add 0.3 cents per kWh for the levelized cost of utility administration of the DG program, from the detailed data on such costs that was assembled last year for the California Public Tool model referenced above.[14]

h. Societal benefits

Renewable DG has benefits to society that do not directly impact utility rates. When renewable generation takes the place of conventional fossil fuel generation, all citizens benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demand on existing water supplies is reduced, avoiding the potential need to acquire new sources of supply. Distributed generation, by siting energy generation in the built environment, results in more land being available for other uses, or as natural habitat. Distributed generation makes the power system more resilient, and stimulates the local economy. Many of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 3% in calculating these benefits, rather than the utility WACCs used for the direct benefits.

Our societal benefits use the Environmental Protection Agency's ("EPA") "AVoided Emissions and geneRation Tool" (AVERT) to calculate the avoided emissions due to solar DG installations in New Hampshire. AVERT calculates hourly avoided emissions based on a given energy efficiency or renewable energy program. Our model assumes 40 MW of DG solar in the state, uses a PV profile for Concord, and the Northeast AVERT regional data file to calculate the avoided emissions in New Hampshire. The avoided emissions for 2015 are shown below.

Table D-8: *2015 Avoided Emissions*

Pollutant	Avoided Emissions	
	lbs	lbs/MWh
SO2	31,400	0.617
NOx	33,100	0.650
CO2	27,400	0.538

The value of these avoided emissions is calculated as follows:

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[13] This estimate is based on the Maine Study's calculation that a 2.5% penetration of wind resources in New England would require additional operating reserves equal to 1.75% of the wind capacity. See Maine Study, at p. 80. We use 1.75% of the avoided generation capacity costs (before the load match factor) in Table D-2 above. This estimate is also consistent with other solar integration studies in the U.S., such as the studies referenced in footnote 7 of the accompanying testimony.

[14] See footnote 12 above.

1. Determine the amount of avoided emissions using AVERT as described above.
2. Calculate the social cost of the avoided emissions and subtract the market value of those emissions.

Carbon. The total social cost of carbon is taken from the EPA's 2015 revision of the *Social Cost of Carbon for Regulatory Impact Analysis*.[15] The EPA calculates the social cost of carbon from 2015-2050 in five year intervals. In this analysis, intermediate years between the five year intervals are interpolated. For the market value of carbon (which we include in avoided energy costs), we extend recent RGGI auction prices through 2021, after which we use the forecasted market value of carbon in Synapse Energy Economic's *Spring 2016 National Carbon Dioxide Price Forecast*.[16] Forecasted market CO_2 values for the years 2016 – 2040 are subtracted from the EPA's social cost of carbon to determine the net social cost of carbon.

SO_2. The analysis for SO_2 follows the same steps as the analysis for carbon. The total social cost of SO_2 is taken from the EPA's *Regulatory Impact Analysis for the Final Clean Power Plan (CPP Impact Analysis)*.[17] The EPA calculated social cost values for 2020, 2025, and 2030. This analysis uses the values given for these three years assuming a 3% discount rate. Values for intermediate years are interpolated between the five-year values. The market value of SO_2 is taken from the EPA's 2016 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was $0.06 per ton.[18] This is low enough compared to the social cost that it is negligible for our calculations.

NOx. The social cost of NOx is the social cost from the EPA's *CPP Impact Analysis.*[19] There is no compliance market price for NOx in the Northeast.[20]

Local Economic Benefits. Distributed generation has higher costs per kW than central station renewable or gas-fired generation. However, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – is spent in the local economy, and thus provides a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. In contrast, central station power plants have significantly lower soft costs, per kW installed, and often are not located in the local area where the power is consumed.

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[15] *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised July 2015). Available at: https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

[16] *Spring 2016 National Carbon Dioxide Price Forecast*. Found at: http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf.

[17] *Regulatory Impact Analysis for the Final Clean Power Plan*. Found at: https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf.

[18] EPA 2016 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2016-so2-allowance-auction.

[19] *CPP Impact Analysis*, at Table 4-7.

[20] See the EPA Cross State Air Pollution Rule. Found at: https://www3.epa.gov/crossstaterule/

There have been a number of recent studies of the soft costs of solar DG, as the industry has focused on reducing such costs, which are higher in the U.S. than in other major international markets for solar PV. The following tables present data from detailed surveys of solar installers conducted by two national labs (LBNL and NREL), which break out the soft costs that are likely to be spent in the local area where the DG customer resides.

Table D-9: *Residential Local Soft Costs*

Local Costs	**LBNL – J. Seel** *et al.*[21]		**NREL – B. Friedman** *et al.*[22]	
	$/watt	**%**	**$/watt**	**%**
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Table D-10: *Commercial Local Soft Costs*

Local Costs	**NREL – B. Friedman** *et al.*			
	Small Commercial		**Large Commercial**	
	$/watt	**%**	**$/watt**	**%**
Total System Cost	4.97	100%	4.05	100%
Local Soft Costs				
Customer acquisition & marketing	0.13	3%	0.03	1%
Installation labor	0.39	8%	0.17	5%
Permitting & interconnection	0.01	0.2%	0.00	0%
Permit fees	0.07	1%	0.04	1%
Total local soft costs	**0.60**	**12%**	**0.24**	**6%**

These local economic benefits occur in the year when the DG capacity is initially built. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same NPV in 2016 dollars. We also use more recent (and lower) solar DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of 4.6 cents per kWh of DG output for residential systems and

[21] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.
[22] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

2.7 cents per kWh for commercial, or an average of 3.8 cents per kWh assuming 56% residential systems, 44% commercial.[23]

Table D-11 summarizes the societal benefits we have calculated.

Table D-11: *Societal Benefits (25-year levelized $/MWh)*

Benefit	Value
Social cost of carbon – reduced damages	23.23
Health benefits – lower PM-2.5 and NOx emissions	36.40
Local economic benefits	38.24
Total Societal Benefits	97.86

i. Summary of Benefits.

Table D-12 summarizes the benefits discussed above. See also **Figure ES-1**.

Table D-12: *Summary of Solar DG Benefits (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Direct			
Energy	63.35	62.98	62.27
Generation Capacity	65.62	55.26	61.66
Generation Capacity Reserves	9.38	7.90	8.82
Solar Integration Costs	*(2.00)*	*(2.00)*	*(2.00)*
ISO-NE Transmission Capacity	19.58	17.06	17.28
Distribution	22.46	29.36	16.55
Market price response (DRIPE)	2.82	2.89	2.96
Program administration	*(3.00)*	*(3.00)*	*(3.00)*
Avoided Fuel Price Uncertainty	27.43	29.33	31.67
Total Direct Benefits	205.64	199.79	196.20
Societal			
Carbon	23.23		
Criteria Pollutants (SOx and NOx)	36.40		
Local economic benefits	38.24		
Total Societal Benefits	97.86		
Total Benefits			
Direct and Societal	303.50	297.70	294.10

[23] This is the current distribution between residential and commercial customers of the 40 MW of solar DG systems now online in the three utility service territories, based on data provided in discovery.

2. Costs of Solar DG for Participants

We have used a pro forma cash flow analysis to project the lifecycle cost of a solar DG system based on 2014-2015 solar system costs in New Hampshire surveyed and reported by Lawrence Berkeley National Lab ("LBNL") in their annual *Tracking the Sun* report.

LBNL's most recent *Tracking the Sun VII and IX* reports from August 2015 and August 2016 include the results of their extensive survey of the trends in solar prices in 2014 and 2015. LBNL's authoritative price surveys of PV installations are based on data from almost one-half of the 965,000 solar PV systems installed in the U.S. through calendar year 2015.[24] **Table D-13** shows this price data for New Hampshire for 2014 and 2015. Residential PV system costs in 2015 actually increased slightly compared to 2014. We have used the lower of 2014 or 2015 costs in our model.

Table D-13: *2014 and 2015 Solar PV Installed Price Data for New Hampshire*[25]

Market Segment	Cost Percentile	Solar PV Costs ($ per watt DC)		
		2014	2015	Model
Residential (< 10 kW)	Median	**3.60**	**3.90**	**3.60**
	20%	3.20	3.40	3.20
	80%	4.50	4.50	4.50
Small Commercial (10 kW to 500 kW)	Median	**3.40**	**3.30**	**3.30**
	20%	3.00	3.00	3.00
	80%	4.00	3.80	3.80

Our principal assumptions in the residential cash flow analysis are summarized in **Table D-14**. We include the modest state incentive as a reduction in participant costs, and also assume that about 50% of solar customers will face property taxes equal to 2% of their system's assessed value.[26] Our analysis also uses typical solar loan terms now offered in New Hampshire.

24 LBNL, *Tracking the Sun IX* (August 2016), at p. 1. These reports are available at https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf and https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report.pdf.

25 LBNL, *Tracking the Sun VIII* (August 2015), data for Figures 19 and 20, and *Tracking the Sun IX* (August 2016), data for Figures 18 and 19.

26 Towns in New Hampshire can offer property tax exemptions or reductions for solar systems, and about 50% do. See https://www.nh.gov/oep/energy/saving-energy/documents/dra-solar-exemption-report.pdf and https://www.nh.gov/oep/energy/saving-energy/documents/solar-repte.pdf.

Table D-14: *Key Assumptions for the Residential Cost of Solar*

Assumption	Value
Median Cost	$3.60 per watt DC
Range of Costs (20th to 80th percentiles)	$3.20 - $4.50 per watt DC
Federal ITC	30%
State incentive	$0.50/watt-AC, up to $2,500
Financing Cost	3%
Participant discount rate	5%
Financing Term	12 years
Property taxes	1% of original cost
Inverter Replacement	$700/kW in Year 15
Maintenance Cost	$26 per kW-year

The assumptions for the levelized costs of small commercial systems are similar, with the addition that commercial systems qualify for accelerated depreciation and are subject to different tax treatment as businesses. **Table D-15** shows the resulting levelized costs of solar energy ("Solar LCOEs") for residential and small commercial customers.

Table D-15: *Summary of Solar LCOEs (25-year levelized $/kWh)*

Market / Installation Cost	Utilities		
	Eversource	Liberty	Unitil
Residential	*53%*	*74%*	*73%*
Median	0.176	0.183	0.163
20th Percentile	0.159	0.165	0.148
80th Percentile	0.213	0.221	0.198
Commercial	*47%*	*26%*	*27%*
Median	0.146	0.149	0.140
20th Percentile	0.141	0.144	0.136
80th Percentile	0.154	0.157	0.147

3. Bill Savings for Participants / Lost Revenues for Non-participating Ratepayers

A primary benefit of solar DG for the customers who install it are the savings that they realize on their utility bills, as a result of the retail rate credits provided through net metering. At the same time, these bill savings also are the primary costs of net metering for non-participating ratepayers, because they are the revenues that the utility loses as a result of DG customers serving their own load.

We have modeled the long-term bill savings that solar customers will realize under the principal residential and small commercial rate schedules for the three utilities. We have modeled the savings assuming a solar system sized to serve 80% of the customer's annual usage, although for most schedules the assumed system size does not have a strong impact on the bill savings. The savings decline over time due to the 0.5% annual degradation in solar output. For the default supply rate, we have developed a model of future default supply rates by analyzing the recent observed relationship between these rates and LMP and capacity market prices in New Hampshire, and then applying this relationship to our forecast of avoided energy and generation capacity prices. In this way, our bill savings and avoided cost benefit models use consistent escalation rates. We assume that the remaining components of utility rates will escalate with inflation.

The current mix of residential and commercial systems installed in 2015 for all three utilities, by installed PV system capacity, is 56% residential and 44% commercial. The share of commercial systems in Eversource's territory (47%) is much higher than for the two smaller utilities (26% and 27%). We assume that this distribution of residential and commercial systems will continue. With this mix, the average levelized bill savings across both the residential and commercial markets is about 15-17 cents per kWh, as shown in the table below.

Table D-16 summarizes the modeled bill savings / lost revenues for the residential and commercial customers of the three utilities.

Table D-16: *Bill Savings / Lost Revenues (25-year levelized $/kWh)*

Market	Utilities		
	Eversource	**Liberty**	**Unitil**
Residential			
Distribution of Systems	*53%*	*74%*	*73%*
Bill Savings / Lost Revenues	0.201	0.192	0.195
Commercial			
Distribution of Systems	*47%*	*26%*	*27%*
Bill Savings / Lost Revenues	0.151	0.140	0.157
Combined Residential and Commercial			
Distribution of Systems	*100%*	*100%*	*100%*
Bill Savings / Lost Revenues	0.177	0.179	0.184

4. Results of the Standard Practice Manual Tests

The tables above provide the three principal sets of benefits and costs necessary to apply the principal *Standard Practice Manual* tests to solar DG in New Hampshire:

A. **Table D-12**: avoided cost benefits of DG (benefits in the TRC and RIM tests)
B. **Table D-15**: LCOE of solar DG (costs in the TRC and Participant tests)
C. **Table D-16**: bill savings/lost revenues (benefits for Participants/costs in RIM test)

Table D-17 summarizes these benefits and costs, and shows the SPM test results for the residential and commercial markets separately, and for both markets combined. Please note that we show the final benefits and costs in 25-year levelized cents per kWh.

Table D-17: *Standard Practice Manual Test Results*

Cost or SPM Test	Utilities		
	Eversource	Liberty	Unitil
Residential	*53%*	*74%*	*73%*
Costs *(25-year levelized cents/kWh)*			
A1. Direct Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	17.6	18.3	16.3
C. Bill Savings / Lost Revenues	20.1	19.2	19.5
SPM Test Results			
TRC – A1 ÷ B	**1.17**	**1.09**	**1.20**
Societal – A2 ÷ B	**1.73**	**1.63**	**1.80**
Participant – C ÷ B	**1.14**	**1.05**	**1.19**
RIM – A1 ÷ C	**1.03**	**1.04**	**1.01**
Commercial	*47%*	*26%*	*27%*
Costs *(25-year levelized cents/kWh)*			
A1. Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	14.6	14.9	14.0
C. Bill Savings / Lost Revenues	15.1	14.0	15.7
SPM Test Results			
TRC – A1 ÷ B	**1.41**	**1.34**	**1.40**
Societal – A2 ÷ B	**2.08**	**2.00**	**2.09**
Participant – C ÷ B	**1.03**	*0.94*	**1.12**
RIM – A1 ÷ C	**1.37**	**1.42**	**1.25**
Combined Residential & Commercial	*100%*	*100%*	*100%*
Costs *(25-year levelized cents/kWh)*			
A1. Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	16.2	17.4	15.7
C. Bill Savings / Lost Revenues	17.7	17.9	18.4
SPM Test Results			
TRC – A1 ÷ B	**1.27**	**1.15**	**1.25**
Societal – A2 ÷ B	**1.88**	**1.71**	**1.87**
Participant – C ÷ B	**1.10**	**1.03**	**1.17**
RIM – A1 ÷ C	**1.16**	**1.12**	**1.06**