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May 8, 2019

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Review of Proposed Power Purchase Agreements
Pursuant to R.I. Gen. Laws § 39-31
Docket No. 4929

Dear Ms. Massaro:

Enclosed for filing with the Rhode Island Public Utilities Commission (PUC) are the responses of National Grid[1] to the PUC's Record Requests issued during hearings in the above-referenced matter and the responses of National Grid to the PUC's Sixth Set of Data Requests.

Please contact me at 617-951-1400 if you have any questions regarding this filing.

Very truly yours,

John K. Habib

John K. Habib, Esq.
R.I. Bar # 7431

cc: Docket No. 4929 Service List

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Docket No. 4929 -- National Grid's Review of PPA w/ WWD Rev I, LLC

Service List updated 4/23/2019

Name/Address	E-mail Distribution	Phone
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Jon Hagopian, Esq. **Division of Public Utilities & Carriers** 89 Jefferson Blvd. Warwick, RI 02888	Jon.hagopian@dpuc.ri.gov; Leo.wold@dpuc.ri.gov; John.bell@dpuc.ri.gov; Ronald.Gerwatowski@dpuc.ri.gov; Thomas.kogut@dpuc.ri.gov; Jonathan.Schrag@dpuc.ri.gov;	401-784-4775
Office of Energy Resources Andrew Marcaccio, Esq. Carol Grant, Commissioner Christopher Kearns, OER Nicholas Ucci, OER	Andrew.Marcaccio@doa.ri.gov; Christopher.Kearns@energy.ri.gov; Nicholas.Ucci@energy.ri.gov; Carol.Grant@energy.ri.gov;	
John Dalton Carson Robers Power Advisory LLC	crobers@poweradvisoryllc.com; jdalton@poweradvisoryllc.com;	
DWW Rev I, LLC Joseph A. Keough Jr., Esquire Keough + Sweeney, Ltd. 41 Mendon Avenue Pawtucket, Rhode Island 02861	jkeoughjr@keoughsweeney.com;	401-724-3600
Conservation Law Foundation (CLF) James Crowley, Esq. Conservation Law Foundation 235 Promenade St., Suite 560, Mailbox 28 Providence, RI 02908	jcrowley@clf.org;	401-228-1905
File an original & 9 copies w/: Luly E. Massaro, Commission Clerk Cynthia Wilson-Frias, Commission Counsel Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Margaret.Hogan@puc.ri.gov;	401-780-2017
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Paulette Hamilton, Lieutenant Governor	Paulette.Hamilton@ltgov.ri.gov;	

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DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	Attachment	CONFIDENTIAL ATTACHMENT
COMMISSION SET 1							
COMMISSION SET 1	PUC 1-1	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-2	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-3	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-4	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-5	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-6	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-7	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-8	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-9	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-10	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery		
COMMISSION SET 1	PUC 1-11	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-12	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery		
COMMISSION SET 1	PUC 1-13	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-14	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-15	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-16	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-17	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	PPA Terms		

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COMMISSION SET 2							
COMMISSION SET 2	PUC 2-1	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 2	PUC 2-2	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Capacity and Reliability		
COMMISSION SET 2	PUC 2-3	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Capacity and Reliability		
COMMISSION SET 2	PUC 2-4	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Capacity and Reliability		
COMMISSION SET 2	PUC 2-5	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 2	PUC 2-6	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 2	PUC 2-7	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 2	PUC 2-8	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 2	PUC 2-9	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 2	PUC 2-9 Supplemental	3/8/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 2	PUC 2-10	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products	Att. PUC 2-10	
COMMISSION SET 2	PUC 2-11	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 2	PUC 2-12	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Emissions and RECs		
COMMISSION SET 2	PUC 2-13	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Emissions and RECs		
COMMISSION SET 2	PUC 2-14	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Emissions and RECs	Att. PUC 2-14	
COMMISSION SET 2	PUC 2-15	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Emissions and RECs		
COMMISSION SET 2	PUC 2-16	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Emissions and RECs	Att. PUC 2-16-1 and Att. PUC 2-16-2	
COMMISSION SET 2	PUC 2-17	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Emissions and RECs		
COMMISSION SET 2	PUC 2-18	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 2	PUC 2-19	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 2	PUC 2-20	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 2	PUC 2-21	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 2	PUC 2-22	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 2	PUC 2-23	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 2	PUC 2-24	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 2	PUC 2-25	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		

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COMMISSION SET 2	PUC 2-26	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-27	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-28	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-29	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-30	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-31	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-32	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-33	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-34	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP		
COMMISSION SET 2	PUC 2-35	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP	Att. PUC 2-35 Redacted	Att. PUC 2-35 Confidential
COMMISSION SET 2	PUC 2-36	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP	Att. PUC 2-36 Redacted	Att. PUC 2-36 Confidential
COMMISSION SET 2	PUC 2-36 Supplemental	3/8/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Reasonableness and RFP	Att. PUC 2-36 Supp. Redacted	Att. PUC 2-36 Supp. Confidential
COMMISSION SET 2	PUC 2-37	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Jobs and Economic Benefits		
COMMISSION SET 2	PUC 2-38	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Jobs and Economic Benefits		
COMMISSION SET 2	PUC 2-39	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Jobs and Economic Benefits		
COMMISSION SET 2	PUC 2-40	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Jobs and Economic Benefits		
COMMISSION SET 2	PUC 2-41	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Jobs and Economic Benefits		
COMMISSION SET 2	PUC 2-42	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling	Att. PUC 2-42	
COMMISSION SET 2	PUC 2-43	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 2	PUC 2-44	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 2	PUC 2-45	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 2	PUC 2-46	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery and Remuneration		
COMMISSION SET 2	PUC 2-47	3/8/2019	3/18/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery and Remuneration		

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COMMISSION SET 3							
COMMISSION SET 3	PUC-3-1	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Follow up		
COMMISSION SET 3	PUC-3-2	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Follow up		
COMMISSION SET 3	PUC-3-3	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Follow up		
COMMISSION SET 3	PUC-3-4	4/1/2019	4/11/2019	Brennan and Corinne M. DiDomenico	Follow up		
COMMISSION SET 3	PUC-3-5	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	RECs	Att. PUC-3-5	
COMMISSION SET 3	PUC-3-6	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Docket 4600 Benefit-Cost Framework	Att. PUC-3-6	
COMMISSION SET 3	PUC-3-7	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Docket 4600 Benefit-Cost Framework		
COMMISSION SET 3	PUC-3-8	4/1/2019	4/15/2019	Brennan and Corinne M. DiDomenico	Modeling	Att. PUC-3-8-1, Att. PUC-3-8-2 and PUC-3-8-3	Confidential and Att. PUC-8-3 Confidential
COMMISSION SET 3	PUC-3-9	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-10	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-11	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling	Att. PUC-3-11-1 and Att. PUC-3-11-2	
COMMISSION SET 3	PUC-3-12	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-13	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-14	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-15	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-16	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC3-17	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-18	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-19	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling	Att. PUC-3-19	
COMMISSION SET 3	PUC-3-20	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-21	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-22	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-23	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-24	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-25	4/1/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 3	PUC-3-26	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling	Att. PUC-3-19	
COMMISSION SET 3	PUC-3-27	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling	Att. PUC-3-27-1 and Att. PUC-3-27-2	

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COMMISSION SET 3	PUC-3-28	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Alternatives		
COMMISSION SET 3	PUC-3-29	4/1/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Alternatives		
COMMISSION SET 3	PUC-3-30	4/1/2019			Alternatives		
COMMISSION SET 3	PUC-3-31	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Alternatives		
COMMISSION SET 3	PUC-3-32	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Alternatives		
COMMISSION SET 3	PUC-3-33	4/1/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Alternatives		

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COMMISSION SET 4							
COMMISSION SET 4	PUC-4-1	4/3/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Energy Procurement		
COMMISSION SET 4	PUC-4-2	4/3/2019	4/11/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Energy Procurement		
COMMISSION SET 4	PUC-4-3	4/3/2019	4/15/2019	Brennan and Corinne M. DiDomenico	Other Energy Procurement	Redacted and Att. PUC-4-3-2 Redacted	Confidential and Att. PUC-4-3-2 Confidential
COMMISSION SET 4	PUC-4-4	4/3/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Energy Procurement		
COMMISSION SET 4	PUC-4-4 CONFIDENTIAL	4/3/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Energy Procurement		
COMMISSION SET 4	PUC-4-5	4/3/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Energy Procurement		
COMMISSION SET 4	PUC-4-5 CONFIDENTIAL	4/3/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Energy Procurement		
COMMISSION SET 4	PUC-4-6	4/3/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Energy Procurement		
COMMISSION SET 5							
COMMISSION SET 5	PUC-5-1	4/5/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 5	PUC-5-2	4/5/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Value of Products		
COMMISSION SET 5	PUC-5-3	4/5/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Other Contract Provisions		
COMMISSION SET 5	PUC-5-4	4/5/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery		
COMMISSION SET 5	PUC-5-5	4/5/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery		
COMMISSION SET 5	PUC-5-6	4/5/2019	4/16/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling	Att. PUC-5-6	
COMMISSION SET 5	PUC-5-7	4/5/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Modeling		
COMMISSION SET 5	PUC-5-8	4/5/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Last Resort Service		
COMMISSION SET 5	PUC-5-9	4/5/2019	4/15/2019	Timothy J. Brennan and Corinne M. DiDomenico	Remuneration		
COMMISSION SET 6							
COMMISSION SET 6	PUC-6-1	5/6/2019	5/8/2019	Timothy J. Brennan and Corinne M. DiDomenico		Att. PUC 6-1	

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DIVISION SET 1							
DIVISION SET 1	DIV 1-1	2/25/2019	3/8/2019	Timothy J. Brennan and Corinne M. DiDomenico	Remuneration	Att. DIV 1-1	
DIVISION SET 1	DIV 1-2	2/25/2019	3/8/2019	Timothy J. Brennan and Corinne M. DiDomenico	Remuneration	Att. DIV 1-2	
DIVISION SET 1	DIV 1-3	2/25/2019	3/8/2019	Timothy J. Brennan and Corinne M. DiDomenico	Remuneration		
DIVISION SET 1	DIV 1-4	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-5	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-6	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-7	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-8	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-9	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-10	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-11	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-12	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration	Att. DIV 1-12-1, DIV 1-12-2, DIV 1-12-3, DIV 1-12-4, DIV 1-12-5, DIV 1-12-6, DIV 1-12-7, DIV 1-12-8, DIV 1-12-9, DIV 1-12-10, DIV 1-12-11, DIV 1-12-12, DIV 1-12-13, DIV 1-12-14, DIV 1-12-15, DIV 1-12-16, DIV 1-12-17, DIV 1-12-18, & DIV 1-12-19	
DIVISION SET 1	DIV 1-13	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-14	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-15	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4929
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	Attachment	CONFIDENTIAL ATTACHMENT
Record Requests							
Record Requests	RR-1	5/2/2019	5/8/2019	Timothy J. Brennan and Corinne M. DiDomenico			
Record Requests	RR-2	5/2/2019	5/8/2019	Timothy J. Brennan and Corinne M. DiDomenico			
Record Requests	RR-3	5/2/2019	5/8/2019	Timothy J. Brennan and Corinne M. DiDomenico			
Record Requests	RR-5	5/2/2019	5/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert			
Record Requests	RR-6	5/2/2019	5/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert			
Record Requests	RR-7	5/2/2019	5/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert			
Record Requests	RR-8	5/2/2019	5/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert			

RR-1

Request:

(Grid) (a) Are facilities that participate in the CASPR auction prohibited by tariff or economics from participating in the initial auction? If it is an economic constraint arising from the minimum offer price, what is that price for offshore wind? (Use FCA 13 or FCA 14); (b) whether TCR's model would allow offshore wind facilities to be new entrants in the initial auction (based on testimony that the generic model does not include offshore wind).

Response:

(a) Section III of the ISO New England, Inc. Transmission, Markets, and Services Tariff (ISO-NE Tariff) contains provisions governing the participation of resources in its Forward Capacity Market, including the following provision applicable to offers from new resources seeking to participate in the primary auction:

> III.13.1.1.2.2.3. Offer Information. (a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

Under Section III.A.21 of the ISO-NE Tariff, the relevant Offer Review Trigger Price for offshore wind energy resources is currently set at the Forward Capacity Auction Starting Price (i.e., $13.10 per kilowatt-month for Forward Capacity Auction 14).

Thus, an offshore wind energy resource would only be able to participate in the primary auction if it is able to justify to the ISO-NE Internal Market Monitor, as competitive, an offer price that is less than the Forward Capacity Auction Starting Price. As further detailed in this section of the ISO-NE Tariff, the resource owner would be required to "indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism" and the "Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price."

(b) After checking the assumptions regarding generic resources that were entered into the model as potential new resources, the TCR witnesses wish to clarify that that the model inputs did include generic offshore wind resources, whose capital and operating cost estimates are sourced

from EIA. The inputs assumed those generic offshore wind resources could potentially be financed on a merchant basis, with the developer required to rely on projected revenues from sales of energy and RECs into the markets for those products at the prices prevailing at the time of sale rather than on a state-sponsored basis supported by long-term contracts at agreed-upon fixed prices for those products.

The capacity expansion module of the TCR model was allowed to choose generic offshore wind resources to meet resource adequacy requirements (installed capacity, RPS/CES and emissions) if they were the least-cost solution. Such resources, like all generic capacity resources in the model, were assumed to be available as potential new entrants in the primary capacity auctions.

TCR did not run the Forward Capacity Market (FCM) pricing module of Enelytix for this analysis.

RR-2

Request:

(Grid) – What factors, in your energy and REC market model were primarily responsible for driving the cost of the contract below market over time?

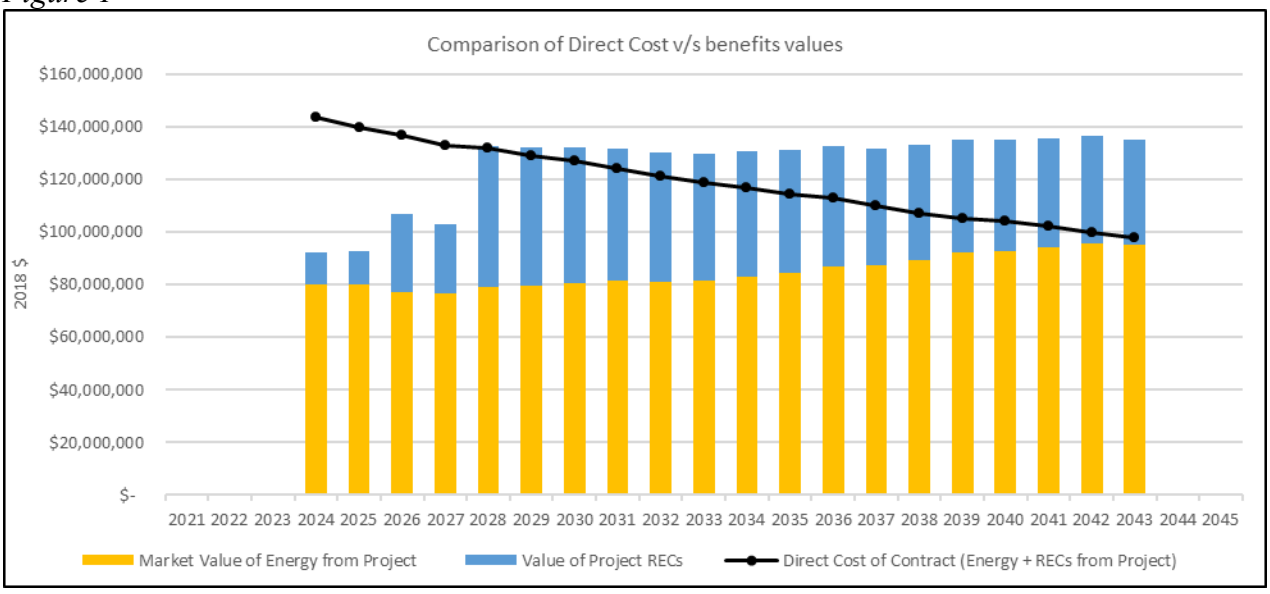
Response:

Over time, the cost of the quantity of energy plus RECs purchased under the contract each year drops below the market value of that quantity of energy plus RECs for two main reasons, as illustrated in Figure 1.

- the annual cost of the quantity of energy plus RECs purchased under the contract each year is fixed in nominal dollars and thus declines over time when expressed in 2018$ due to inflation.
- the market value of the quantity of energy plus RECs purchased under the contract is expressed in 2018$, and that amount is projected to increase over time due to the projected increases in market prices for energy and RECs over time.

Figure 1 provides a comparison of the annual cost of contract (black line) compared to the annual market value of MWh from the project broken out as the market value of energy (yellow bars) and the market value of RECs (blue bars).

Figure 1



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The annual costs of energy plus RECs from the project are above their market value in the first four years of the contract, as illustrated by the gap between annual cost and annual market value from 2024 through 2027. Those annual costs are below the annual market values from 2028 onward.

1. The market value of the energy purchased under the contract is projected to gradually increase over the PPA period reflecting the changing market conditions of the proposal case. Figure 2 presents the underlying averaged LMPs by ISO-NE load zone and describes key parameters driving the trends in the energy price (i.e., value of proposal energy); and
2. The market value of the RECs purchased under the contract is projected to be significantly lower in the first four years of the PPA due to supply-driven suppression of REC prices in those years. A regional shortfall of physical RECs from 2028 onward is met through ACPs in Connecticut, which then sets the price of RECs. Figure 3 presents the underlying regional REC prices and describes key parameters driving the trends in REC price (i.e., value of proposal RECs).

Figure 2

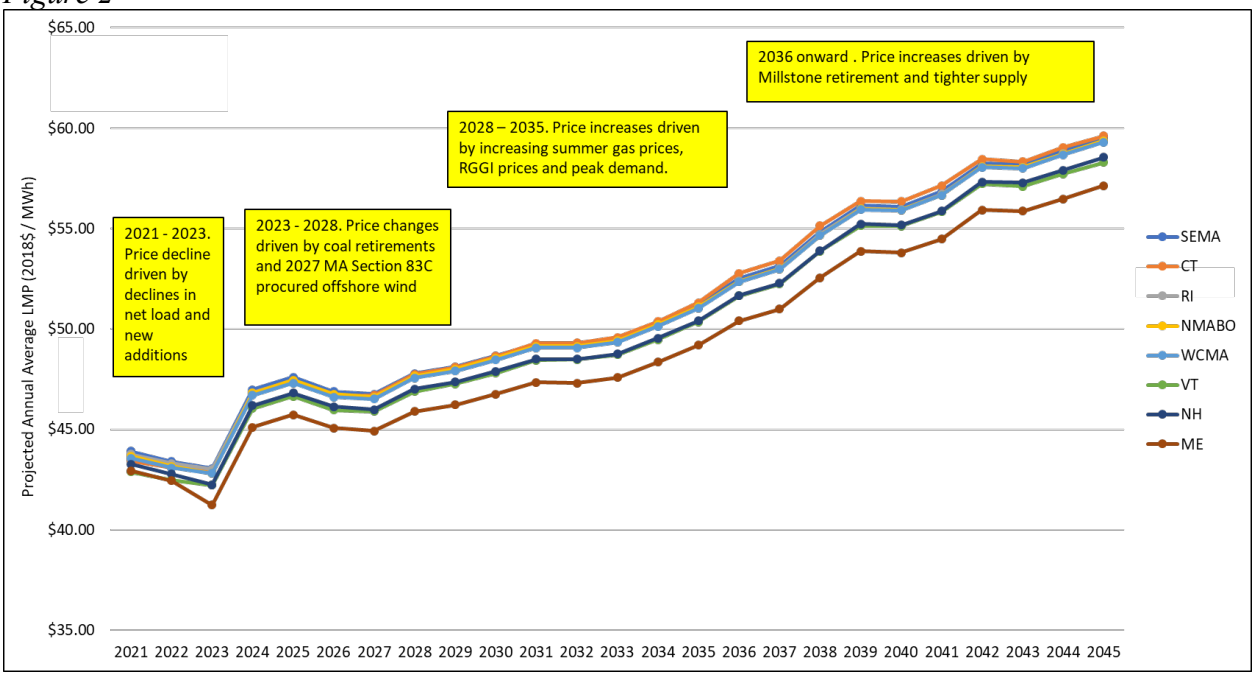
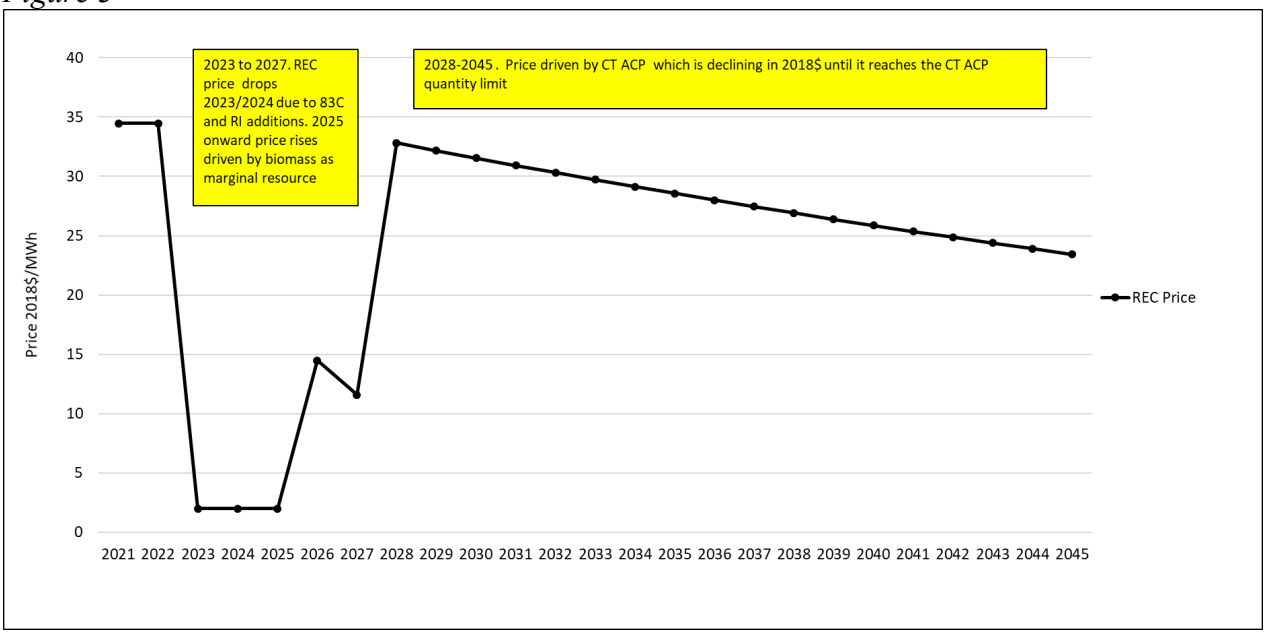


Figure 3


2023 to 2027. REC price drops 2023/2024 due to 83C and RI additions. 2025 onward price rises driven by biomass as marginal resource
2028-2045 . Price driven by CT ACP which is declining in 2018$ until it reaches the CT ACP quantity limit
Price 2018$/MWh
0
5
10
15
20
25
30
35
40
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
REC Price

RR-3

Request:

(Grid) – (a) What are the model assumptions that inform the $28.7M in gas supply cost reduction to RI gas customers? (b) What changes would National Grid need to make to its gas procurement process or procedures to realize this level of savings?

Response:

(a) The model assumptions that inform the $28.7M in gas supply cost reduction to Rhode Island gas customers incorporate the "Comparison of Resources and Requirements Base Normal Year" from the Company's 2018 Long Range Plan (LRP) to forecast the annual requirements and the heating season requirements with New England basis exposure. The LRP provides a ten-year forecast of gas supply requirements out to and including the 2026/27 rate year. The Company used the last year of the LRP as the forecast beyond 2027. The Company's consultant, TCR, calculated an impact to the forward prices of New York Mercantile Exchange Henry Hub Natural Gas (NYMEX) and the New England locational basis. The NYMEX price is recognized as the benchmark price for all natural gas supplies in the US and the New England locational basis price is the price differential between NYMEX and gas delivered into the New England region. The NYMEX price change was applied to the annual requirements in the LRP to calculate the expected savings for all gas purchased and the New England basis price change was applied to the Tennessee Gas Pipeline (TGP) Everett. The TGP Everett supplies are the only supplies listed in the LRP Base Normal Heating Season with potential exposure to New England basis.

(b) No change to the Company's gas procurement process is needed to realize these savings. Gas commodity procurements are executed on a short-term basis (up to two years in advance), and therefore the savings will be realized in such future purchases after the Revolution Wind project is in service. The Company enters into long-term capacity agreements (up to 20 years) when the LRP requirements indicate a need for incremental assets to serve Rhode Island customers (e.g., pipeline contracts, LNG liquid, and LNG storage). However, the New England basis price has very little impact on the Company's decision to secure incremental assets, and no impact on the cost to build the asset.

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RR-5

Request:

(Grid) – Are you confident that the way the model captured the facility's operations in the extreme winter captures how the facility would have been able to operate in the 2013-2014 weather?

Response:

The TCR model simulated the operations of the Revolution Wind facilities and the Vineyard Wind facilities in both the Proposal Case, and in the extreme winter weather scenario of the Proposal case, based upon the hourly generation profiles, capacity factor estimates and monthly adjustment factors provided by the bidders. The Company and TCR considered this to be a reasonable approach because the bidders have a strong financial incentive to operate their facilities according to those parameters under the range of weather conditions expected at their facility locations.

RR-6

Request:

Energy and RECs procured from project: when do you pay for the products, when do receive revenues for the products?

Response:

Section 5.2 (a) of the Power Purchase Agreement (PPA) requires the Seller to provide an invoice by the 15th day following the end of each month. Section 5.2 (b) stipulates that all payments are due for the products on or before the later of 15 days after receipt of the invoice or the last day of the calendar month in which the invoice was received. For example, the invoice for January 2024 should be provided by February 15, 2024. The Company will pay for the products by the later of 15 days after receipt of invoice, or by February 29, 2024.

The Seller shall deliver Energy through Internal Bilateral Transactions (IBTs) executed through ISO New England, Inc. (ISO-NE). The deadline for a Real Time IBT for initial settlement is by 5:00 PM on the second business day following an operating day. For example, a January 1st operating day requires a Real Time IBT to be submitted by 5:00 PM on January 3rd. The IBT results in the credit of ISO-NE energy revenue from the generation to the Company's ISO-NE settlement account. On Monday and Wednesday (or on the following Business Day, if Monday or Wednesday is a Holiday), the ISO-NE provides the Company with a bill for energy market settlements.[1] This bill will include any energy revenue from the IBTs during the same period.

For example, in January 2024 the Seller will enter an IBT for each operating day. The energy revenue associated with each operating day will appear on the applicable Monday and Wednesday settlement reports throughout January and February from the ISO-NE. The later operating days of January will be submitted in IBTs in February and will appear in early February ISO-NE settlement reports.

The receipt of REC revenue will vary. There is a four to six month lag between a generation month and the minting of Renewable Energy Certificates (RECs) that are deposited in the Company's NEPOOL-GIS account. For example, RECs from generation delivered in January 2024 through March 2024 will not be minted as RECs until July 15, 2024. Under the current Renewable Energy Standard (RES) Procurement Plan, the Company uses RECs from PPAs to meet its Standard Offer Service (SOS) customers' RES obligations. The SOS customers will 'pay' for those RECs when the RECs are deposited in its NEPOOL-GIS account. For example,

[1] See, e.g.,: https://www.iso-ne.com/static-assets/documents/mkts_billing/bill_tutorial/billing_settlement_timeline.pdf.

the January 2024 generation RECs will be minted and deposited in the Company's account on July 15, 2024. The Company will calculate a transfer price at the end of the month to facilitate the transfer of REC dollars from SOS customers to all distribution customers.

However, the Company may decide to not use the RECs from this project for its SOS customers' RES obligations, in which case the Company will sell the RECs. The first opportunity to sell RECs from energy delivered in January through March would be July 15th, the opening of the first NEPOOL-GIS trading period. The REC revenues associated with a July 15th delivery would be received several weeks later, per the terms of the REC transaction agreements. REC revenue will be received within 15 business days following the delivery and sale each quarter. The receipt of REC revenue for RECs delivered on the first day of the NEPOOL-GIS trading period would be as follows:

Generation Quarter	First Day of NEPOOL-GIS Trading Period	Approximate Receipt of REC Revenue
1st Quarter	July 15th	August 5th
2nd Quarter	October 15th	November 5th
3rd Quarter	January 15th	February 5th
4th Quarter	April 15th	May 6th

RR-7

Request:

Please produce a cash working capital analysis and if you can't, explain why.

Response:

National Grid has not performed a working capital analysis because it would require too many assumptions that would prove too speculative and variable to be useful.

There are several significant challenges to developing a reliable pro-forma cash working capital study. First, the Company will receive revenue from three sources: the sale of energy, the sale of RECs, and customer rates. The proportion of revenue that comes from each of these three sources will vary based on fluctuations in generation, future market prices for energy and RECs, and (as discussed below) future forecasts for energy and REC prices. Because the lag period from the three sources are different, the proportion of revenue from each source will have a meaningful effect on cash working capital requirements. In addition, the fluctuations in generation volumes will cause swings in working capital requirements.

Moreover, the lag associated with revenue from the LTC Recovery Factor (discussed below) can fluctuate widely depending on the size and accuracy of future energy market price and REC price forecasts. These can vary from lead times (i.e., over-recoveries) to lag times (recovery of actual costs, and under-recoveries). The uncertainty associated with the lead/lag time of this component of revenue would undermine any pro-forma working capital estimate developed at this time.

A general description of the timing of the Company's payments to Revolution Wind, sales of energy to ISO-NE and sales of Renewable Energy Credits to NEPOOL is provided in the response to Record Request RR-6. A discussion of the working capital requirements associated with revenue collected from customers is below. The process described assumes recovery through the LTC Recovery Provision as proposed in this docket.

Please also note, the 2.75 percent Remuneration Rate is not intended to be an offset for the Company's increased cash working capital requirements. As discussed in the Company's response to Data Request DIV 1-5, the proposed 2.75 percent Remuneration Rate serves the purpose of: (1) enabling the public policy goals contemplated by the ACES Act; (2) partially mitigating the opportunity cost to NEC (and its investors) of committing the Company's balance sheet to support the financial obligation of the Revolution Wind PPA; and (3) helping address the likely adverse effects on NEC's ongoing financial flexibility and credit profile brought about by the large, long-term, fixed financial obligation of entering into the PPA contract.

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Current Operation of the LTC Recovery Provision

The Company's LTC Recovery Provision allows for the concurrent recovery of the estimated above (below)-market cost of long-term renewable energy contracts, which consists of payments made under long-term contracts executed pursuant to R.I. Gen. Laws Chapter 39-26.1 and the distributed generation standard contracts executed pursuant to R.I. Gen. Laws Chapter 39-26.2, less the proceeds obtained from the sale of energy, capacity, and Renewable Energy Certificates (RECs),[1] and also provides for the recovery of other costs and credits, such as remuneration, and operates with the Company's Long-Term Contracting for Renewable Energy Recovery Reconciliation Provision, RIPUC No. 2175, to allow for the recovery of those costs as incurred.

As the Company's LTC Recovery Provision provides, the Company recovers (credits) the above (below)-market cost of the contracts for two six-month Pricing Periods (January through June and July through December). Total expected contract payments are estimated by applying unit availability factors to unit capacities to develop an estimated megawatt-hour output and multiplying that amount by the per-megawatt-hour contract price. The expected market value of energy is based on NYMEX electricity futures for the Pricing Period and renewable resource generation shapes (output in on-peak hours and off-peak hours). The REC proxy value is based on the Company's most recent market estimate.

The total above (below)-market cost plus estimated incremental administrative costs from participation in the FCM is divided by the forecasted kWh deliveries during the Pricing Period. After adjustment for the Company's most recently-approved uncollectible allowance percentage, the resulting uniform per-kilowatt-hour factor becomes the base LTC Recovery Factor for the applicable Pricing Period. For billing purposes, the LTC Recovery Factor is included in the Renewable Energy Distribution kWh charge on customers' bills.

The Company bills the LTC Recovery Factor to all of its customers as part of its standard billing process. The Company reads its meters located at customers' service locations and bills its customers based on those metering reads over 20 cycles. Cycle meter reading and billing is used by the Company as it is physically impossible for the Company to read the meters of its almost 500,000 electric customers on the last day of each calendar month. As each cycle's meters are read, the readings are typically processed the same night and a bill is generated that night. Bills are then mailed the following day after they are printed. Therefore, 20 times during a billing month, the Company is mailing a group of bills to its customers based on its cycle billing schedule. Therefore, there is a billing lag, which is the number of days to process and mail a paper bill.

[1] The value credited to customers in the LTC Recovery mechanism is either net proceeds from selling the RECs produced by the projects or the transfer value of RECs produced and used by the Company to comply with its Renewable Energy Standard obligation.

Finally, while bills are due upon receipt, the Company generally allows a period of time for customers to pay their bills. This is known as the payment lag.

See response to RR-6 for a description of the cashflow associated energy and RECs, which can result in a four to six-month lag. The Company is reading meters and billing its customers for usage that crosses calendar months, and customers do not pay those bills immediately when received, but rather, on average, several days after service is rendered (measured as the mid-point between two meter read dates). This lag from when meters are read and payment is received is called the Revenue Lag and is determined as the sum of the billing lag and payment lag. The Company updates its Revenue Lag annually pursuant to its Standard Offer Adjustment Provision, RIPUC No. 2157, associated with the recovery of Standard Offer Service Administrative costs. Most recently, in RIPUC Docket No. 4930, the Company calculated its revenue lag, and the lag calculated was 51.23 days (a 49.76-day payment lag plus a 1.47-day billing lag). See Schedule REP-6, at 7.

Implications for Revolution Wind PPA

The LTC Recovery Factor will reflect Revolution Wind's estimated above-market costs in the Pricing Period in which the project is first expected to go online. Assuming Revolution Wind will begin producing power in January 2024, the project's costs will begin to be recovered through a change in the LTC Recovery Factor effective during the January 2024 to June 2024 Pricing Period. Based upon how rate changes are implemented on a prorated, or usage on and after, basis, in the first month the Company will bill customers over its 20 billing cycles and, for purposes of the component of the LTC Recovery Factor that would be supporting the Revolution Wind PPA, would be assessed only to usage during January 2024. This results in the revenue billed to customers in the first month of the recovery of the Revolution Wind PPA reflecting from 40 percent to 60 percent of the service month, based on the meter reading and billing schedule for January 2024. The remainder of the revenue for the Pricing Period would be realized after the end of the six months, as June 2024 usage is billed in July 2024. As discussed above, the Company's revenue lag calculated in the Annual Retail Rate Filing in Docket No. 4930, is 51.23 days and the payment lag associated with the PPA market revenues can be as much as 6 months.

RR-8

Request:

(Grid) – Please identify (a) if, and where, the 20-year PPA obligation will appear on Narragansett Electric's FERC Form 1 and (b) if and where on any of National Grid plc's financial statements. If the Company can't answer part (b), please explain why and indicate, where are the existing long term contracts for renewable energy being reported on the consolidated National Grid plc financial statement.

Response:

Based on discussions with the Company's accounting department, the location and disclosure of the 20-year PPA obligation will be impacted by the accounting treatment of the overall agreement. As of April 1, 2019, The Narragansett Electric Company (Narragansett) has adopted the provisions of Accounting Standards Codification (ASC) 842, *Leases*. Because the PPA will only commence after the adoption date, it is assessed under the new standard. The PPA is not expected to qualify as a lease agreement under ASC 842, because Narragansett does not control the use of the underlying wind farm. Because the PPA is not expected to qualify as a lease, the forward purchase agreement related to the electricity component of the contract is expected to qualify as a derivative instrument under the U.S. Generally Accepted Accounting Principles (GAAP). At this time, the Company anticipates that:

(a) On Narragansett's FERC Form 1, the derivative instrument will be recorded at fair value on the balance sheet on page 112, line 32, Long Term Portion of Derivative Instrument Liabilities, with the current portion reflect on page 113, line 50, Derivative Instrument Liabilities. The unrealized gains and losses on the PPA will be deferred and recorded on page 111, line 72, Other Regulatory Assets. If the overall fair value of the PPA is favorable to Narragansett, the amounts would be reclassified to the Derivative Instrument Asset accounts on the balance sheet, and a related Regulatory Liability account.

The purchases under the agreement will be included on the Income Statement on page 114 and 115, line 4, as a component of Operating Expense. The excess amount of the outputs purchased will be sold back into the market and recorded on the Income Statement on page 114 and 115, line 4, also as a component of Operating Expense. The difference between the contract price paid and the market price for the purchases under the contract will be deferred and included on the balance sheet on page 111, line 72, Other Regulatory Assets.

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The Balance Sheet and related Income Statement activity will also be captured as part of the notes to the financial statements on derivative instruments and regulatory accounting within page 123 of the FERC Form 1.

In addition, the Company would only consider including this information in its financial statements at some point after the contract has obtained regulatory approval and after the wind farm has obtained its permits, approvals, and financing necessary to start construction. The Company would consider all relevant facts and circumstances of the project when those factors are met. In addition, qualitative information about the contracts will be disclosed within the Commitments and Contingencies footnote as part of the notes to the financial statements within page(s) 123 of the FERC Form 1.

(b) On a consolidated basis, National Grid USA has a portfolio of agreements for the purchase of power, including from renewable resources, which have a variety of accounting conclusions based on the terms of the underlying contracts. For National Grid USA under U.S. GAAP, the accounting location and disclosure considerations are consistent with the response to part (a) above.

For National Grid plc under IFRS, any fair value attributed to the PPA will be recorded within Derivative Financial Liabilities (or assets) on the Consolidated Statement of Financial Position. The change in fair value will be reflected on the Consolidated Income Statement within Operating Profit as part of remeasurements on commodity contract derivatives. The purchases under the contract, and any income or loss from the sale of any excess output received, will be included within Operating Profit on the Consolidated Income Statement. IFRS does not have a regulatory accounting standard akin to US GAAP; any amounts received or paid related to deferrals of costs or refunds of income from/to customers will be recognized on the Consolidated Income Statement as a component of Operating Profit when received or paid back in rates. Consistent with response (a), disclosure around the contract is expected within the Derivative Financial Instruments and Commitments footnotes in the National Grid plc financial statements.

Please note that the consolidated results of operations and the financial positions of both National Grid USA and National Grid plc are much larger than those of Narragansett. Consequently, disclosure around the PPA I is expected to be less substantial in the consolidated financial statements than it would be for Narragansett.

PUC 6-1

Request:

Using the historical information for the period 1998-2017 located at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/ (2019 Forecast Data), please use any relevant adjustments National Grid believes necessary (or none), and explain any adjustments.

a. Please use a solid black line to plot a graph of the actual summer peak load for New England from 1998 to present.

b. On the same graph, please plot the appropriate ISO New England CELT Report summer peak forecast for each CELT Report using a different color line for the forecast in each CELT Report. Please identify the peak data used (e.g., net of PV).

c. Please provide a table with the data depicted in the graph.

Response:

a. Please refer to Attachment PUC 6-1 for the requested graphs and data tables for historic and forecasted weather normalized summer peak data. National Grid has not made any adjustments. This includes:
   - Weather normalized annual summer peak for load ISO-NE (Gross) in tabs '1Ch Sum Peak (Gross)' and '1 Sum Peak (Gross)'; and
   - Weather normalized annual summer peak for load ISO-NE (Net of PV and PDR) in tabs '2Ch Sum Peak (Net)' and '2 Sum Peak (Net)'.

b. Please refer to the response to part a, above.

c. Please refer to the response to part a, above.

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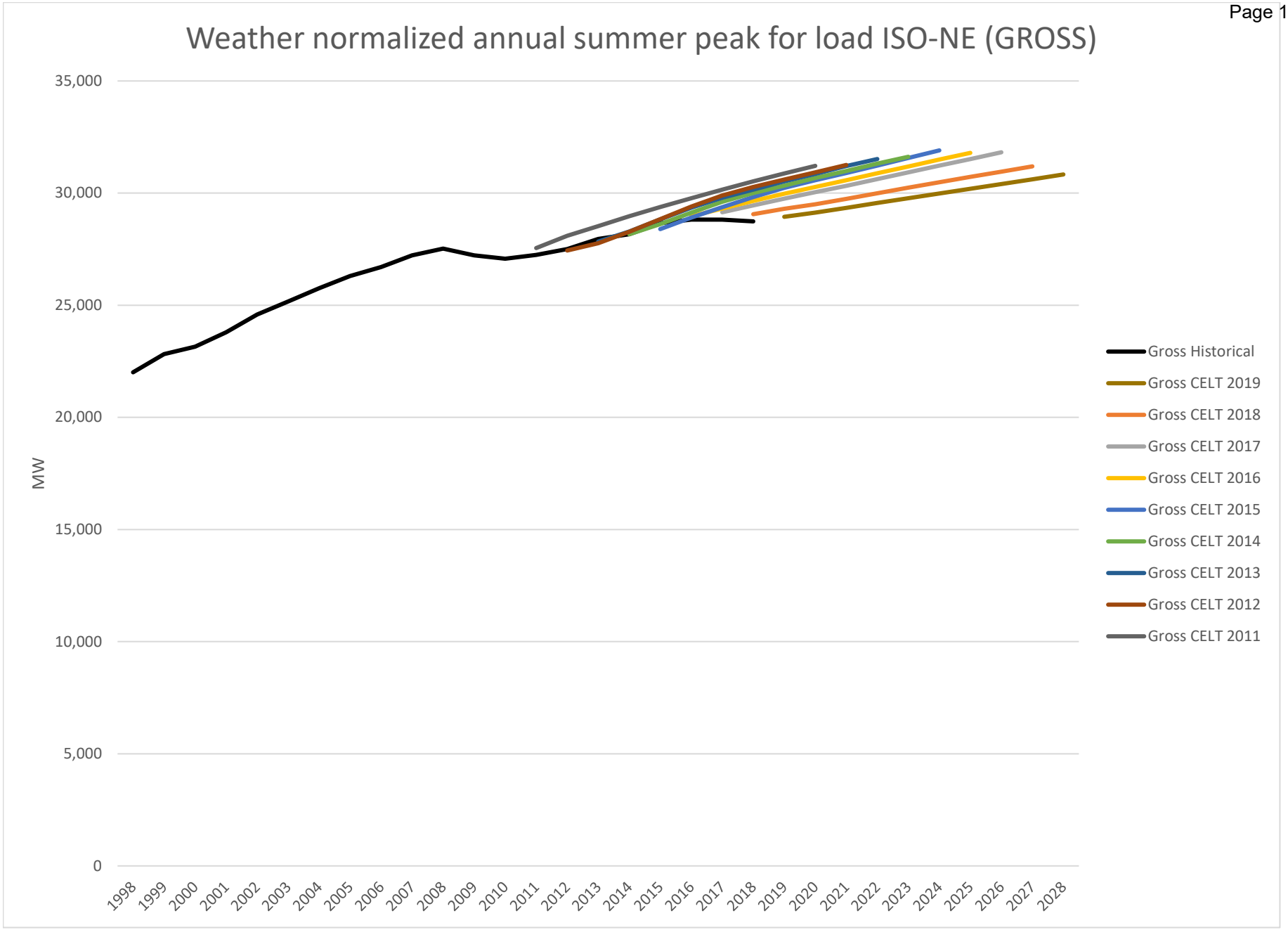
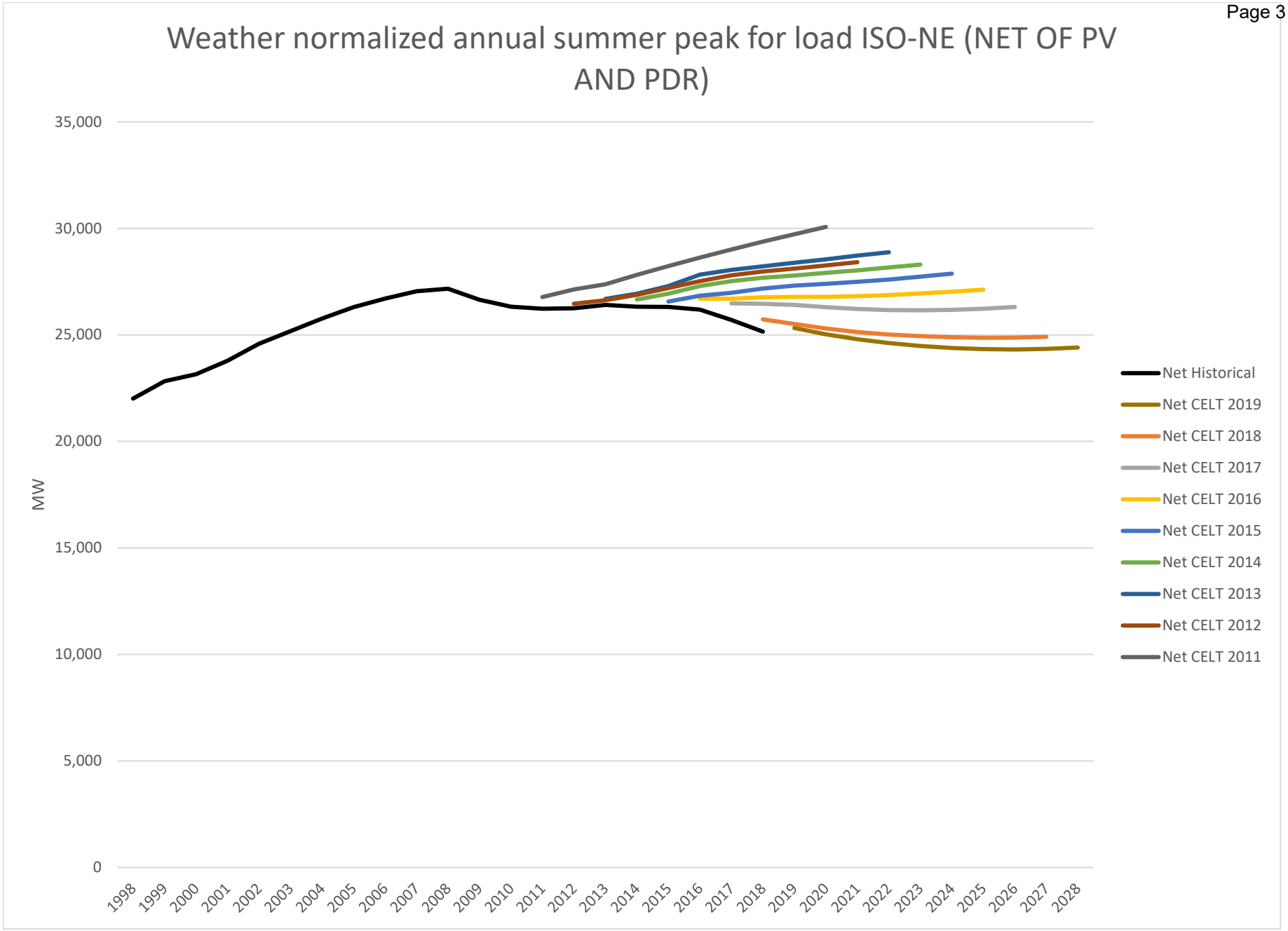

Weather normalized annual summer peak for load ISO-NE (GROSS)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Gross Historical
Gross CELT 2019
Gross CELT 2018
Gross CELT 2017
Gross CELT 2016
Gross CELT 2015
Gross CELT 2014
Gross CELT 2013
Gross CELT 2012
Gross CELT 2011

Weather normalized annual summer peak for load ISO-NE (GROSS)

MW	Gross									
	Historical	CELT 2019	CELT 2018	CELT 2017	CELT 2016	CELT 2015	CELT 2014	CELT 2013	CELT 2012	CELT 2011
1998	22,010									
1999	22,825									
2000	23,150									
2001	23,790									
2002	24,590									
2003	25,170									
2004	25,760									
2005	26,305									
2006	26,700									
2007	27,220									
2008	27,525									
2009	27,220									
2010	27,075									
2011	27,240									27550
2012	27,507								27440	28095
2013	27,952							27840	27765	28525
2014	28,171						28165	28290	28275	28970
2015	28,660					28395	28615	28825	28840	29380
2016	28,815				28966	28910	29130	29350	29400	29775
2017	28,817			29,146	29307	29375	29610	29790	29895	30155
2018	28,740		29,060	29,454	29652	29825	30005	30155	30275	30525
2019		28,943	29,298	29,753	29975	30230	30335	30525	30605	30875
2020		29,130	29,504	30,039	30276	30575	30675	30860	30930	31215
2021		29,341	29,744	30,327	30578	30900	30990	31205	31255	
2022		29,561	29,994	30,623	30883	31230	31315	31520		
2023		29,774	30,245	30,923	31190	31570	31620			
2024		29,987	30,486	31,223	31493	31905				
2025		30,196	30,721	31,521	31794					
2026		30,406	30,957	31,820						
2027		30,616	31,192							
2028		30,831								


Weather normalized annual summer peak for load ISO-NE (NET OF PV AND PDR)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Net Historical
Net CELT 2019
Net CELT 2018
Net CELT 2017
Net CELT 2016
Net CELT 2015
Net CELT 2014
Net CELT 2013
Net CELT 2012
Net CELT 2011

Weather normalized annual summer peak for load ISO-NE (NET OF PV AND PDR)

MW	Net									
	Historical	CELT 2019	CELT 2018	CELT 2017	CELT 2016	CELT 2015	CELT 2014	CELT 2013	CELT 2012	CELT 2011
1998	22,010									
1999	22,825									
2000	23,150									
2001	23,790									
2002	24,590									
2003	25,170									
2004	25,760									
2005	26,305									
2006	26,700									
2007	27,053									
2008	27,167									
2009	26,650									
2010	26,327									
2011	26,229									26,776
2012	26,248								26,462	27,135
2013	26,405							26,690	26,629	27,377
2014	26,324						26,658	26,929	26,877	27,822
2015	26,310					26,565	26,930	27,290	27,193	28,232
2016	26,185				26,704	26,835	27,291	27,830	27,520	28,627
2017	25,698			26,482	26,698	26,976	27,521	28,053	27,797	29,007
2018	25,156		25,729	26,458	26,764	27,178	27,677	28,213	27,973	29,377
2019		25,323	25,512	26,409	26,782	27,310	27,782	28,391	28,111	29,727
2020		25,025	25,298	26,298	26,788	27,399	27,911	28,546	28,257	30,067
2021		24,793	25,136	26,213	26,817	27,487	28,028	28,721	28,414	
2022		24,620	25,021	26,167	26,870	27,598	28,167	28,878		
2023		24,479	24,942	26,155	26,942	27,733	28,298			
2024		24,383	24,889	26,176	27,026	27,875				
2025		24,329	24,864	26,228	27,122					
2026		24,315	24,874	26,310						
2027		24,341	24,912							
2028		24,408								