nationalgrid

Celia B. O'Brien
Assistant General Counsel and Director

March 5, 2018

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4770 – Application of The Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric and Gas Base Distribution Rates
<u>Supplemental Responses to Division 5-3 and Division 5-4</u>

Dear Ms. Massaro:

Enclosed is an original of the Company's[1] supplemental responses to Division 5-3 and Division 5-4 in the above-referenced docket.

This filing includes a Motion for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B) for the Company's supplemental responses to data requests Division 5-3 and Division 5-4. The Company seeks protection from public disclosure of the confidential information contained in (1) Attachment DIV 5-3-3 CONFIDENTIAL and Attachment DIV 5-3-4 CONFIDENTIAL provided with the supplemental response to data request Division 5-3 and (2) Attachment DIV 5-4-1 CONFIDENTIAL and Attachment DIV 5-4-2 CONFIDENTIAL provided with the supplemental response to data request Division 5-4. Please note that these confidential attachments are Excel files, which the Company seeks to protect from public disclosure in their entirety. Accordingly, the Company is providing the PUC with these confidential Excel files on a USB Flash Drive in a sealed envelope marked "**Contains Privileged and Confidential Information – Do Not Release**."

The supplemental responses to Division 5-3 and Division 5-4 are listed in the enclosed discovery log and the enclosed table of contents.

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

280 Melrose Street, Providence, RI 02907
T: 781-907-2153 ■ celia.obrien@nationalgrid.com ■ www.nationalgrid.com

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2153.

Very truly yours,

Celia B. O'Brien

Celia B. O'Brien

Enclosures

cc: Docket 4770 Service List
Macky McCleary, Division
Jonathan Schrag, Division
John Bell, Division
Al Mancini, Division
Ron Gerwatowksi, Division
Leo Wold, Esq.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
BEFORE THE PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID – ELECTRIC AND GAS DISTRIBUTION RATE FILING	)))))	Docket No. 4770

THE COMPANY'S MOTION FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Company[1] respectfully requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws. § 38-2-2(4)(B). The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On February __, 2018, the Company filed supplemental responses to data requests Division 5-3 and Division 5-4 from the Rhode Island Division of Public Utilities and Carriers' (the Division) Fifth Set of Data Requests in Docket 4770 from the Division of Public Utilities to National Grid dated January 3, 2018 (Division Set 5). These supplemental responses to these data requests from Division Set 5 include Attachment DIV 5-3-3 CONFIDENTIAL, Attachment DIV 5-3-4 CONFIDENTIAL, Attachment DIV 5-4-1 CONFIDENTIAL, and Attachment DIV 5-4-2 CONFIDENTIAL. These attachments are Excel files that contain confidential and proprietary commercial and financial information. Specifically, these Excel files contain cost inputs, which are derived from competitively sensitive information that the Company has

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

received from third party vendors on a confidential basis. This is information that the Company ordinarily would not share with the public. Therefore, the Company requests that, pursuant to Rule 1.2(g), the PUC afford confidential treatment to Attachment DIV 5-3-3 CONFIDENTIAL, Attachment DIV 5-3-4 CONFIDENTIAL, Attachment DIV 5-4-1 CONFIDENTIAL, and Attachment DIV 5-4-2 CONFIDENTIAL, in their entirety.

II. LEGAL STANDARD

PUC Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). Therefore, to the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of the APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either to (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The information contained in Attachment DIV 5-3-3 CONFIDENTIAL, Attachment DIV 5-3-4 CONFIDENTIAL, Attachment DIV 5-4-1 CONFIDENTIAL, and Attachment DIV 5-4-2 CONFIDENTIAL contain confidential and proprietary commercial and financial information relating to the Company's business operations. Specifically, these attachments contain cost inputs, which are derived from competitively sensitive information that the Company has received from third party vendors on a confidential basis, and which the Company ordinarily would not disclose to the public.

The Company, therefore, is providing confidential Attachment DIV 5-3-3 CONFIDENTIAL, Attachment DIV 5-3-4 CONFIDENTIAL, Attachment DIV 5-4-1 CONFIDENTIAL, and Attachment DIV 5-4-2 CONFIDENTIAL to the PUC on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to these attachments in their entirety.

IV. CONCLUSION

Accordingly, the Company respectfully requests that the PUC grant protective treatment to Attachment DIV 5-3-3 CONFIDENTIAL, Attachment DIV 5-3-4 CONFIDENTIAL, Attachment DIV 5-4-1 CONFIDENTIAL, and Attachment DIV 5-4-2 CONFIDENTIAL.

WHEREFORE, the Company respectfully requests that the PUC grant this Motion for Protective Treatment.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY

By its attorneys,

____

Celia B. O'Brien, Esq. (RI #4484)
National Grid
280 Melrose Street
Providence, RI 02907
(781) 907-2153

____

Adam M. Ramos, Esq. (RI #7591)
Hinckley, Allen & Snyder LLP
100 Westminster Street, Suite 1500
Providence, RI 02903-2319
(401) 457-5164

Dated: March 5, 2018

Certificate of Service

I hereby certify that a copy of the cover letter and/or any materials accompanying this certificate were electronically transmitted and/or hand delivered to the individuals listed below.

Najat Coye

___________________________________ March 5, 2018

Najat Coye Date

Docket No. 4770 - National Grid – Rate Application
Service list updated 2/23/2018

Name/Address	E-mail Distribution List	Phone
National Grid Celia O'Brien, Esq. Jennifer Hutchinson, Esq. National Grid 280 Melrose St. Providence, RI 02907	Celia.obrien@nationalgrid.com; Jennifer.hutchinson@nationalgrid.com; Najat.coye@nationalgrid.com; Joanne.scanlon@nationalgrid.com; Bill.Malee@nationalgrid.com; Melissa.little@nationalgrid.com; William.richer@nationalgrid.com; Theresa.burns@nationalgrid.com; Ann.leary@nationalgrid.com; Scott.mccabe@nationalgrid.com; Najat.coye@nationalgrid.com; kayte.o'neill2@nationalgrid.com; kate.grant2@nationalgrid.com; Mary.coleman@nationalgrid.com; Timothy.roughan@nationalgrid.com;maria.harvey@nationalgrid.com	781-907-2153 401-784-7288
Adam Ramos, Esq. Hinckley Allen Hinckley Allen 100 Westminster Street, Suite 1500 Providence, RI 02903-2319	aramos@hinckleyallen.com;	401-457-5164
Division of Public Utilities (Division) Leo Wold, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov; Jmunoz@riag.ri.gov; Dmacrae@riag.ri.gov;	404-274-4400
Jonathan Schrag, Deputy Administrator Division of Public Utilities and Carriers 89 Jefferson Blvd. Warwick, RI 02888	Jonathan.Schrag@dpuc.ri.gov; Macky.McCleary@dpuc.ri.gov; John.bell@dpuc.ri.gov; Al.mancini@dpuc.ri.gov; Thomas.kogut@dpuc.ri.gov;	401-780-2140

	Joseph.shilling@dpuc.ri.gov;	
Tim Woolf Jennifer Kallay Synapse Energy Economics 22 Pearl Street Cambridge, MA 02139	twoolf@synapse-energy.com; jkallay@synapse-energy.com; mwhited@synapse-energy.com; jhall@synapse-energy.com;	617-661-3248
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
Bruce Oliver Tim Oliver Revilo Hill Associates 7103 Laketree Drive Fairfax Station, VA 22039	Boliver.rha@verizon.net; tim.b.oliver@gmail.com;	703-569-6480
Matt Kahal 1108 Pheasant Crossing Charlottesville, VA 22901	mkahal@exeterassociates.com;	434-964-0604
Ronald Gerwatowski Nicole Rohr	gerwat@verizon.net; Ronald.Gerwatowski@dpuc.ri.gov; nrohr443@g.rwu.edu;	508-259-7963
M. Ballaban LaCapra Associates	mballaban@daymarkea.com;	
T. Bennett S. Bobo Daymark Energy Advisors	tbennett@daymarkea.com; sbobo@daymarkea.com;	
William Dunkel and Associates 8625 Farmington Cemetery Road Pleasant Plains, IL 62677	WilliamDunkel@consultant.com; RoxieMcCullar@consultant.com;	217-626-1934
Office of Energy Resources (OER) Andrew Marcaccio, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Andrew.Marcaccio@doa.ri.gov;	401-222-8880
Carol Grant, Commissioner Office of Energy Resources	Carol.grant@energy.ri.gov; Christopher.Kearns@energy.ri.gov; Danny.Musher@energy.ri.gov; Nicholas.Ucci@energy.ri.gov ; Becca.Trietch@energy.ri.gov; Carrie.Gill@energy.ri.gov;	401-574-9100
Conservation Law Foundation (CLF) Jerry Elmer, Esq. Max Greene, Esq. Conservation Law Foundation 235 Promenade Street Suite 560, Mailbox 28 Providence, RI 02908	jelmer@clf.org; mgreene@clf.org;	401-228-1904

Dept. of Navy (DON) Kelsey A. Harrer, Esq. Office of Counsel NAVFAC Atlantic, Department of the Navy 6506 Hampton Blvd. Norfolk, VA 23508-1278	kelsey.a.harrer@navy.mil;	757-322-4119
Kay Davoodi, Director Larry R. Allen, Public Utilities Specialist Utilities Rates and Studies Office NAVFAC HQ, Department of the Navy 1322 Patterson Avenue SE Suite 1000 Washington Navy Yard, D.C. 20374	khojasteh.davoodi@navy.mil; larry.r.allen@navy.mil;	
New Energy Rhode Island (NERI) Seth H. Handy, Esq. Handy Law, LLC 42 Weybosset St. Providence, RI 02903	seth@handylawllc.com; helen@handylawllc.com; randelle@handylawllc.com;	401-626-4839
The RI League of Cities and Towns c/o Brian Daniels, Executive Director	bdaniels@rileague.org;	401 272-3434
PRISM & WCRPC c/o Jeff Broadhead, Executive Director	jb@wcrpc.org;	401-792-9900
Newport Solar c/o Doug Sabetti	doug@newportsolarri.com;	401.787.5682
Green Development, LLC c/o Michelle Carpenter	mc@green-ri.com;	401.295.4998
Clean Economy Development, LLC c/o Julian Dash	jdash@cleaneconomydevelopment.com;	
ISM Solar Development, LLC c/o Michael Lucini	mlucini@ismgroup.com;	401.435.7900
Heartwood Group, Inc. c/o Fred Unger	unger@hrtwd.com;	401.861.1650
Energy Consumers Alliance of NE James Rhodes Rhodes Consulting 860 West Shore Rd. Warwick, RI 02889 Kat Burnham, PPL	jamie.rhodes@gmail.com; Kat@ripower.org;	401-225-3441
Acadia Center Robert D. Fine, Esq. Chace, Ruttenberg & Freedman, LLP	rfine@crfllp.com;	401-453-6400 Ext. 115

One Park Row, Suite 300 Providence, RI 02903 Amy Boyd, Esq. Acadia Center 31 Milk St., Suite 501 Boston MA 02109-5128	aboyd@acadiacenter.org; ENiedowski@acadiacenter.org; Mlebel@acadiacenter.org;	617-472-0054 Ext. 102
Northeast Clean Energy Council Joseph A. Keough, Jr., Esq. Keough & Sweeney 41 Mendon Ave. Pawtucket, RI 02861 Jannet Besser, NECEC	jkeoughjr@keoughsweeney.com; jbesser@necec.org; jdickerson@necec.org;	401-724-3600
The George Wiley Center John Willumsen-Friedman, Esq. Deputy Director Rhode Island Center for Justice 1 Empire Plaza, Suite 410 Providence, RI 02903 Camilo Viveros, Wiley Center	jwillumsen@centerforjustice.org; georgewileycenterri@gmail.com; Camiloviveiros@gmail.com; chloechassaing@hotmail.com;	401-491-1101 Ext. 810
Wal-Mart Stores East & Sam's East, Inc. Melissa M. Horne, Esq. Higgins, Cavanagh & Cooney, LLC 10 Dorrance St., Suite 400 Providence, RI 20903	mhorne@hcc-law.com;	401-272-3500
Gregory W. Tillman, Sr. Mgr./ERA Walmart	Greg.tillman@walmart.com;	479-204-1594
Original & 9 copies file w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov ; Margaret.hogan@puc.ri.gov;	401-780-2107
Interested Persons		
EERMC Marisa Desautel, Esq . Kate Desrochers	marisa@desautelesq.com; guerard@optenergy.com; kdesrochers@veic.org; loiter@optenergy.com;	401-477-0023
Bob Chatham	bchatham@vcharge-energy.com;	401-742-8264
John DiTomasso, AARP	jditomasso@aarp.org;	401-248-2655
Frank Epps, EDP	Frank@edp-energy.com;	
Matt Davey	mdavey@ssni.com;	
Jesse Reyes	JReyes@brownrudnick.com;	
Nathan Phelps	nathan@votesolar.org;	
Douglas W. Gablinske, TEC-RI	doug@tecri.org;	
Karl Rabago	krabago@law.pace.edu;	

Radina Valova, Pace Energy & Climate Ctr.	rvalova@law.pace.edu;	
Marc Hanks, Sr. Mgr./GRA Direct Energy Services	Marc.hanks@directenergy.com; cwaksler@eckertseamans.com;	413-642-3575

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
COMMISSION SET 1						
COMMISSION SET 1	PUC 1-1	11/28/2017	12/19/2017	Melissa Little	Financial Reporting	
COMMISSION SET 1	PUC 1-2	11/28/2017	12/19/2017	Melissa Little	Financial Reporting	
COMMISSION SET 1	PUC 1-3	11/28/2017	12/19/2017	Melissa Little	Financial Reporting	
COMMISSION SET 1	PUC 1-4	11/28/2017	12/19/2017	Melissa Little	Financial Reporting	
COMMISSION SET 1	PUC 1-5	11/28/2017	12/19/2017	Melissa Little	Income and Cash Flow Statements	
COMMISSION SET 1	PUC 1-6	11/28/2017	12/19/2017	Melissa Little	Affiliates	
COMMISSION SET 1	PUC 1-7	11/28/2017	12/19/2017	Melissa Little	Audits	Attachment 1-7-1, Attachment 1-7-2
COMMISSION SET 1	PUC 1-8	11/28/2017	12/19/2017	Timothy Horan	Investor Relations	
COMMISSION SET 1	PUC 1-9	11/28/2017	12/19/2017	Timothy Horan	Investor Relations	
COMMISSION SET 1	PUC 1-10	11/28/2017	12/19/2017	Joshua Nowak	Treasury	
COMMISSION SET 1	PUC 1-11	11/28/2017	12/19/2017	Melissa Little	Earned Return on Average Common Equity	
COMMISSION SET 1	PUC 1-12	11/28/2017	12/19/2017	Melissa Little	Earnings Report Filed in Docket 4323	
COMMISSION SET 1	PUC 1-12 SUPPLEMENTAL	11/28/2017	1/4/2018	Melissa Little	Earnings Report Filed in Docket 4323	
COMMISSION SET 1	PUC 1-13	11/28/2017	12/19/2017	Joseph Gredder, Theodore Poe, Melissa Little	Forecasts	
COMMISSION SET 1	PUC 1-14	11/28/2017	12/19/2017	Joshua Nowak	Debt and Equity Rating	
COMMISSION SET 1	PUC 1-15	11/28/2017	12/19/2017	Melissa Little	Plant In Service	
COMMISSION SET 1	PUC 1-16	11/28/2017	12/19/2017	John Currie, Sonny Anand	Capital Authorization	
COMMISSION SET 1	PUC 1-17	11/28/2017	12/19/2017	Melissa Little	Construction Work In Progress	
COMMISSION SET 1	PUC 1-18	11/28/2017	12/19/2017	Melissa Little	Depreciation Accrual Rates	
COMMISSION SET 1	PUC 1-19	11/28/2017	12/19/2017	Melissa Little	Company's Test Year O&M Expense Accounts	
COMMISSION SET 1	PUC 1-20	11/28/2017	12/19/2017	Melissa Little and the Legal Department	Service Level Agreements	Attachment 1-20-1, Attachment 1-20-35
COMMISSION SET 1	PUC 1-21	11/28/2017	12/19/2017	Melissa Little	Expenses	
COMMISSION SET 1	PUC 1-22	11/28/2017	12/19/2017	Melissa Little	Allocated Expenses	
COMMISSION SET 1	PUC 1-23	11/28/2017	12/19/2017	Melissa Little	Extraordinary Income	
COMMISSION SET 1	PUC 1-24	11/28/2017	12/19/2017	John Isberg	New Service Offerings	
COMMISSION SET 1	PUC 1-25	11/28/2017	12/19/2017	Melissa Little	Miscellaneous Revenues	
COMMISSION SET 1	PUC 1-26	11/28/2017	12/19/2017	Melissa Little	Chart of Accounts	
COMMISSION SET 1	PUC 1-27	11/28/2017	12/19/2017	Maureen Heaphy	Employee Bonus and Incentive Compensation	
COMMISSION SET 1	PUC 1-28	11/28/2017	12/19/2017	Maureen Heaphy	Compensation and Benefits	
COMMISSION SET 1	PUC 1-29	11/28/2017	12/19/2017	William H. Hilbrunner, Melissa Little	Corporate Policy	
COMMISSION SET 1	PUC 1-30	11/28/2017	12/19/2017	Melissa Little	Loans or Forgiveness of Debts	
COMMISSION SET 1	PUC 1-31	11/28/2017	12/19/2017	Melissa Little	Wages, Salaries and Overheads	
COMMISSION SET 1	PUC 1-31 CORRECTED	11/28/2017	2/1/2018	Melissa Little	Wages, Salaries and Overheads	
COMMISSION SET 1	PUC 1-32	11/28/2017	12/19/2017	Maureen Heaphy	Wage and Salary Increases	
COMMISSION SET 1	PUC 1-33	11/28/2017	12/19/2017	Maureen Heaphy	Wage Contracts	
COMMISSION SET 1	PUC 1-34	11/28/2017	12/19/2017	Maureen Heaphy	Wage and Salary Increases	
COMMISSION SET 1	PUC 1-35	11/28/2017	12/19/2017	Maureen Heaphy	Number of Employees	
COMMISSION SET 1	PUC 1-36	11/28/2017	12/19/2017	Maureen Heaphy	Overtime Wages, Salaries, Hours	
COMMISSION SET 1	PUC 1-37	11/28/2017	12/19/2017	Melissa Little	Actuarial Reports	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
COMMISSION SET 1	PUC 1-38	11/28/2017	12/19/2017	Maureen Heaphy	Non-Pension Benefits	
COMMISSION SET 1	PUC 1-39	11/28/2017	12/19/2017	Maureen Heaphy	Health Care Costs	
COMMISSION SET 1	PUC 1-40	11/28/2017	12/19/2017	Maureen Heaphy	Health Care Costs	
COMMISSION SET 1	PUC 1-41	11/28/2017	12/19/2017	William H. Hilbrunner, Melissa Little	Leased Vehicles	
COMMISSION SET 1	PUC 1-42	11/28/2017	12/19/2017	William H. Hilbrunner, Melissa Little	Vehicle Replacement	
COMMISSION SET 1	PUC 1-43	11/28/2017	12/19/2017	Melissa Little	Aircraft and Watercraft	
COMMISSION SET 1	PUC 1-44	11/28/2017	12/19/2017	Melissa Little	Operations and Maintenance Expenses	
COMMISSION SET 1	PUC 1-45	11/28/2017	12/19/2017	Melissa Little	Dues and Membership	
COMMISSION SET 1	PUC 1-46	11/28/2017	12/19/2017	Melissa Little	Administrative Expenses	
COMMISSION SET 1	PUC 1-47	11/28/2017	12/19/2017	Melissa Little	Insurance Policies	
COMMISSION SET 1	PUC 1-48	11/28/2017	12/19/2017	Timothy Kiernan, Melissa Little	Insurance Policies	
COMMISSION SET 1	PUC 1-49	11/28/2017	12/19/2017	Maureen Heaphy	Insurance Policies	
COMMISSION SET 1	PUC 1-50	11/28/2017	12/19/2017	Timothy Kiernan, Melissa Little	Self insurance Procedure	
COMMISSION SET 1	PUC 1-51	11/28/2017	12/19/2017	Melissa Little	Lease Type Expenses	
COMMISSION SET 1	PUC 1-52	11/28/2017	12/19/2017	Melissa Little	Miscellaneous Deferred Debits	
COMMISSION SET 1	PUC 1-53	11/28/2017	12/19/2017	Melissa Little	Out of Period Adjustments	
COMMISSION SET 1	PUC 1-54	11/28/2017	12/19/2017	Melissa Little	Deferred Credits	
COMMISSION SET 1	PUC 1-55	11/28/2017	12/19/2017	Melissa Little	Outside Services	
COMMISSION SET 1	PUC 1-56	11/28/2017	12/19/2017	Melissa Little, Jody Allison	Gross Write-offs and Recoveries	
COMMISSION SET 1	PUC 1-57	11/28/2017	12/19/2017	Melissa Little, Jody Allison	Uncollectibles	
COMMISSION SET 1	PUC 1-58	11/28/2017	12/19/2017	Melissa Little, Jody Allison	Uncollectible Write-Offs	
COMMISSION SET 1	PUC 1-59	11/28/2017	12/19/2017	Melissa Little, Jody Allison	Accounting Policies - Write-Offs	
COMMISSION SET 1	PUC 1-60	11/28/2017	12/19/2017	Melissa Little	Unbilled Revenues	
COMMISSION SET 1	PUC 1-61	11/28/2017	12/19/2017	Melissa Little	Advertising and Media Related Costs	
COMMISSION SET 1	PUC 1-62	11/28/2017	12/19/2017	Melissa Little	Donations	
COMMISSION SET 1	PUC 1-63	11/28/2017	12/19/2017	Melissa Little	Lobbying Expenses	
COMMISSION SET 1	PUC 1-64	11/28/2017	12/19/2017	Melissa Little	Corporate Identification	
COMMISSION SET 1	PUC 1-65	11/28/2017	12/19/2017	Melissa Little and the Legal Department	Legal Matters	
COMMISSION SET 1	PUC 1-66	11/28/2017	12/19/2017	Melissa Little and the Legal Department	Legal Matters	
COMMISSION SET 1	PUC 1-67	11/28/2017	12/19/2017	Melissa Little and the Legal Department	Legal Matters	
COMMISSION SET 1	PUC 1-68	11/28/2017	12/19/2017	Melissa Little and the Legal Department	Legal Matters	
COMMISSION SET 1	PUC 1-69	11/28/2017	12/19/2017	Melissa Little	Legal Matters	
COMMISSION SET 1	PUC 1-70	11/28/2017	12/19/2017	Melissa Little	Property Taxes	
COMMISSION SET 1	PUC 1-71	11/28/2017	12/19/2017	Melissa Little	Property Taxes	
COMMISSION SET 1	PUC 1-72	11/28/2017	12/19/2017	Melissa Little	Property Taxes	
COMMISSION SET 1	PUC 1-73	11/28/2017	12/19/2017	Melissa Little	Book/Tax Timing Differences	
COMMISSION SET 1	PUC 1-74	11/28/2017	12/19/2017	Melissa Little	Corporate Charges	
COMMISSION SET 1	PUC 1-75	11/28/2017	12/19/2017	Melissa Little	Outside Services Charges	
COMMISSION SET 1	PUC 1-76	11/28/2017	12/19/2017	Melissa Little	Common Plant	
COMMISSION SET 1	PUC 1-77	11/28/2017	12/19/2017	Melissa Little	Affiliates	
COMMISSION SET 1	PUC 1-78	11/28/2017	12/19/2017	Melissa Little	Political Contributions	
COMMISSION SET 1	PUC 1-79	11/28/2017	12/19/2017	Melissa Little	Outside Legal Fees	
COMMISSION SET 1	PUC 1-80	11/28/2017	12/19/2017	Melissa Little	Consulting Services Expenses	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
COMMISSION SET 1	PUC 1-81	11/28/2017	12/19/2017	Melissa Little	Organization Chart	
COMMISSION SET 1	PUC 1-82	11/28/2017	12/19/2017	Maureen Heaphy	Employee Termination Contracts	
COMMISSION SET 1	PUC 1-83	11/28/2017	12/19/2017	Melissa Little, Jody Allison	Physical Terminations	
COMMISSION SET 1	PUC 1-84	11/28/2017	12/19/2017	Melissa Little	Employee Lcation	
COMMISSION SET 1	PUC 1-85	11/28/2017	12/19/2017	Ann Leary	Customers in Each Customer Class	
COMMISSION SET 1	PUC 1-86	11/28/2017	12/19/2017	John Isberg	Advertising	
COMMISSION SET 1	PUC 1-87	11/28/2017	12/19/2017	Howard Gorman	System Peak	
COMMISSION SET 1	PUC 1-88	11/28/2017	12/19/2017	Howard Gorman	Customer Usage	
COMMISSION SET 1	PUC 1-89	11/28/2017	12/19/2017	Howard Gorman	Net Metering	
COMMISSION SET 1	PUC 1-90	11/28/2017	12/19/2017	Anuraag Bhargava, Daniel J. DeMauro, Mukund Ravipaty, Melissa Little	SAP	
COMMISSION SET 2						
COMMISSION SET 2	PUC 2-1	11/28/2017	12/15/2017	David Beron	E-183 Undergrounding and Customer Credit	
COMMISSION SET 2	PUC 2-2	11/28/2017	12/15/2017	David Beron	E-183 Undergrounding and Customer Credit	
COMMISSION SET 2	PUC 2-3	11/28/2017	12/15/2017	Scott M. McCabe	E-183 Undergrounding and Customer Credit	
COMMISSION SET 3						
COMMISSION SET 3	PUC 3-1	12/15/2017	1/5/2018	Jody Allison	Theft of Utility Service	
COMMISSION SET 3	PUC 3-2	12/15/2017	1/5/2018	Jody Allison	Theft of Utility Service	
COMMISSION SET 3	PUC 3-3	12/15/2017	1/5/2018	Jody Allison	Theft of Utility Service	
COMMISSION SET 3	PUC 3-4	12/15/2017	1/5/2018	Jody Allison	Theft of Utility Service	
COMMISSION SET 3	PUC 3-5	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-6	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-7	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-8	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-9	12/15/2017	1/5/2018	Robert Hevert, Scott M. McCabe, Ann E. Leary	Return on Equity	
COMMISSION SET 3	PUC 3-10	12/15/2017	1/5/2018	Robert Hevert, Scott M. McCabe, Ann E. Leary	Return on Equity	
COMMISSION SET 3	PUC 3-11	12/15/2017	1/5/2018	Robert Hevert, Scott M. McCabe, Ann E. Leary	Return on Equity	
COMMISSION SET 3	PUC 3-12	12/15/2017	1/5/2018	Robert Hevert, Scott M. McCabe, Ann E. Leary	Return on Equity	
COMMISSION SET 3	PUC 3-13	12/15/2017	1/5/2018	Robert Hevert, Scott M. McCabe, Ann E. Leary	Return on Equity	
COMMISSION SET 3	PUC 3-14	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-15	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-16	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-17	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-18	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-19	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-20	12/15/2017	1/5/2018	Robert Hevert	Return on Equity	
COMMISSION SET 3	PUC 3-21	12/15/2017	1/5/2018	Joseph Gredder	Delivery Forecasting	
COMMISSION SET 3	PUC 3-22	12/15/2017	1/5/2018	Joseph Gredder	Delivery Forecasting	
COMMISSION SET 3	PUC 3-23	12/15/2017	1/5/2018	Joseph Gredder	Delivery Forecasting	
COMMISSION SET 3	PUC 3-24	12/15/2017	1/5/2018	Theodore Poe	Delivery Forecasting	
COMMISSION SET 3	PUC 3-25	12/15/2017	1/5/2018	John Isberg	Low Income Program Proposals	
COMMISSION SET 3	PUC 3-26	12/15/2017	1/5/2018	John Isberg	Low Income Program Proposals	
COMMISSION SET 3	PUC 3-27	12/15/2017	1/5/2018	John Isberg	Low Income Program Proposals	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
COMMISSION SET 3	PUC 3-28	12/15/2017	1/5/2018	John Isberg	Low Income Program Proposals	
COMMISSION SET 3	PUC 3-29	12/15/2017	1/5/2018	John Isberg	Low Income Program Proposals	
COMMISSION SET 3	PUC 3-30	12/15/2017	1/5/2018	Melissa Little	Personnel	
COMMISSION SET 3	PUC 3-31	12/15/2017	1/5/2018	Melissa Little	Personnel	
COMMISSION SET 3	PUC 3-32	12/15/2017	1/5/2018	Melissa Little	Personnel	
COMMISSION SET 3	PUC 3-33	12/15/2017	1/5/2018	Alfred Amaral	Personnel	
COMMISSION SET 3	PUC 3-34	12/15/2017	1/5/2018	Alfred Amaral	Personnel	
COMMISSION SET 3	PUC 3-35	12/15/2017	1/5/2018	Alfred Amaral	Personnel	
COMMISSION SET 3	PUC 3-36	12/15/2017	1/5/2018	Alfred Amaral	Personnel	
COMMISSION SET 3	PUC 3-37	12/15/2017	1/5/2018	Raymond Rosario	Personnel	
COMMISSION SET 3	PUC 3-38	12/15/2017	1/5/2018	Raymond Rosario	Personnel	
COMMISSION SET 3	PUC 3-39	12/15/2017	1/5/2018	Melissa Little	General	
COMMISSION SET 3	PUC 3-40	12/15/2017	1/5/2018	Scott M. McCabe	Rates	
COMMISSION SET 3	PUC 3-41	12/15/2017	1/5/2018	Melissa Little	Rates	
COMMISSION SET 3	PUC 3-42	12/15/2017	1/5/2018	Scott M. McCabe	Rates	
COMMISSION SET 3	PUC 3-43	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-44	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-45	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-46	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-47	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-48	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-49	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-50	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-51	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-52	12/15/2017	1/5/2018	Jody Allison	Collections	
COMMISSION SET 3	PUC 3-53	12/15/2017	1/5/2018	Jody Allison	Collections	
DIVISION SET 1						
DIVISION SET 1	DIVISION 1-1	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-2	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-3	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-4	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-5	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-6	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-7	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-8	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-9	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-10	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-11	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-12	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 1	DIVISION 1-13	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-14	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-15	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-16	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-17	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-18	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-19	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-20	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-21	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Electric (2016 Electric Depreciation Study)	
DIVISION SET 1	DIVISION 1-22	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-23	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	Attachment 1-23-5
DIVISION SET 1	DIVISION 1-24	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-25	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-26	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-27	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-28	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-29	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-30	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-31	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-32	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-33	12/19/2017	1/8/2018	Melissa Little	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-34	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 1	DIVISION 1-35	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-36	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-37	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 1	DIVISION 1-38	12/19/2017	1/8/2018	Ned W. Allis	Schedule NWA-2 Gas (2016 Gas Depreciation Study)	
DIVISION SET 2						
DIVISION SET 2	DIVISION 2-1	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-2	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-3	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-4	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-5	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-6	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-7	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-8	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-9	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-10	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-11	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-12	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-13	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-14	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-15	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-16	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-17	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-18	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-19	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-20	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-21	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-22	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-23	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-24	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-25	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-26	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 2	DIVISION 2-27	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-28	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-29	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-30	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-31	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-32	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-33	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-34	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-35	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-36	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-37	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-38	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-39	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-40	12/21/2017	1/10/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-41	12/21/2017	1/8/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-42	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-43	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-44	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-45	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 2	DIVISION 2-46	12/21/2017	1/9/2018	Melissa Little	Revenue Requirements	
DIVISION SET 3						
DIVISION SET 3	DIVISION 3-1	12/21/2017	1/8/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-2	12/21/2017	1/9/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-3	12/21/2017	1/9/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-4	12/21/2017	1/9/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-5	12/21/2017	1/9/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-6	12/21/2017	1/8/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-7	12/21/2017	1/11/2018	Melissa Little	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-8	12/21/2017	1/9/2018	Melissa Little	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-9	12/21/2017	1/11/2018	Melissa Little	New Hires and Labor Costs	
DIVISION SET 3	DIVISION 3-10	12/21/2017	1/9/2018	Melissa Little	New Hires and Labor Costs	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 3	DIVISION 3-11	12/21/2017	1/11/2018	John Isberg	Customer Affordability Program and Energy Innovation Hub	
DIVISION SET 3	DIVISION 3-12	12/21/2017	1/9/2018	John Isberg	Customer Affordability Program and Energy Innovation Hub	
DIVISION SET 3	DIVISION 3-13	12/21/2017	1/9/2018	John Isberg	Customer Affordability Program and Energy Innovation Hub	
DIVISION SET 3	DIVISION 3-14	12/21/2017	1/9/2018	John Isberg	Customer Affordability Program and Energy Innovation Hub	
DIVISION SET 3	DIVISION 3-15	12/21/2017	1/9/2018	John Isberg	Customer Affordability Program and Energy Innovation Hub	
DIVISION SET 3	DIVISION 3-16	12/21/2017	1/11/2018	Melissa Little	Service Company Employee Charges	
DIVISION SET 3	DIVISION 3-17	12/21/2017	1/9/2018	Melissa Little	Service Company Rents	
DIVISION SET 3	DIVISION 3-18	12/21/2017	1/9/2018	Melissa Little	Service Company Rents	
DIVISION SET 3	DIVISION 3-19	12/21/2017	1/9/2018	Melissa Little	Service Company Rents	
DIVISION SET 3	DIVISION 3-20	12/21/2017	1/11/2018	Melissa Little	Service Company Rents	
DIVISION SET 3	DIVISION 3-21	12/21/2017	1/11/2018	Melissa Little	Service Company Rents	
DIVISION SET 3	DIVISION 3-22	12/21/2017	1/10/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-23	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-24	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-25	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-26	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-27	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-28	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-29	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-30	12/21/2017	1/10/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-31	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-32	12/21/2017	1/8/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 3	DIVISION 3-33	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-34	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-35	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-36	12/21/2017	1/10/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-37	12/21/2017	1/8/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-38	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-39	12/21/2017	1/10/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-40	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-41	12/21/2017	1/10/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-42	12/21/2017	1/10/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-43	12/21/2017	1/11/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-44	12/21/2017	1/11/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-45	12/21/2017	1/10/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 3	DIVISION 3-46	12/21/2017	1/10/2018	Melissa Little	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-47	12/21/2017	1/11/2018	Melissa Little	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-48	12/21/2017	1/9/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-49	12/21/2017	1/10/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-50	12/21/2017	1/9/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-51	12/21/2017	1/9/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-52	12/21/2017	1/9/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-53	12/21/2017	1/9/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-54	12/21/2017	1/11/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	Attachment 3-54
DIVISION SET 3	DIVISION 3-55	12/21/2017	1/11/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-56	12/21/2017	1/10/2018	Melissa Little	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-57	12/21/2017	1/10/2018	Melissa Little	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-58	12/21/2017	1/11/2018	Melissa Little	Gas Business Enablement Program	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 3	DIVISION 3-59	12/21/2017	1/10/2018	Melissa Little	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-60	12/21/2017	1/10/2018	Melissa Little	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-61	12/21/2017	1/9/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-62	12/21/2017	1/10/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-63	12/21/2017	1/11/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-63 SUPPLEMENTAL	12/21/2017	1/21/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-64	12/21/2017	1/11/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 3	DIVISION 3-65	12/21/2017	1/9/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
COMMISSION SET 4						
COMMISSION SET 4	PUC 4-1	12/21/2017	1/11/2018	Melissa Little	Revenue Requirment / Tax	
COMMISSION SET 4	PUC 4-2	12/21/2017	1/11/2018	Melissa Little	Revenue Requirment / Tax	
COMMISSION SET 4	PUC 4-3	12/21/2017	1/11/2018	Melissa Little	Revenue Requirment / Tax	
COMMISSION SET 4	PUC 4-4	12/21/2017	1/11/2018	Melissa Little	Revenue Requirment / Tax	
COMMISSION SET 4	PUC 4-5	12/21/2017	1/11/2018	Melissa Little	Revenue Requirment / Tax	
COMMISSION SET 4	PUC 4-6	12/21/2017	1/9/2018	Melissa Little	Revenue Requirment / Tax	
COMMISSION SET 4	PUC 4-7	12/21/2017	1/11/2018	Melissa Little	Revenue Requirment / Tax	
COMMISSION SET 4	PUC 4-8	12/21/2017	1/9/2018	Raymond Rosario	Terms and Conditions	
COMMISSION SET 4	PUC 4-9	12/21/2017	1/9/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	Terms and Conditions	
COMMISSION SET 4	PUC 4-10	12/21/2017	1/10/2018	Maureen Heaphy	Employees	
COMMISSION SET 4	PUC 4-11	12/21/2017	1/10/2018	Maureen Heaphy	Employees	
COMMISSION SET 4	PUC 4-12	12/21/2017	1/10/2018	Alfred Amaral, Raymond Rosario, Ryan Constable	Employees	
COMMISSION SET 4	PUC 4-13	12/21/2017	1/9/2018	Joshua Nowak	Capital Structure/ROE	
COMMISSION SET 4	PUC 4-14	12/21/2017	1/9/2018	Joshua Nowak	Capital Structure/ROE	
COMMISSION SET 4	PUC 4-15	12/21/2017	1/8/2018	Ann Leary, Scott McCabe	Low Income	
COMMISSION SET 4	PUC 4-16	12/21/2017	1/8/2018	Scott McCabe	Low Income	
COMMISSION SET 4	PUC 4-17	12/21/2017	1/9/2018	John Isberg	Low Income	
COMMISSION SET 4	PUC 4-18	12/21/2017	1/11/2018	Melissa Little	Technology	
COMMISSION SET 4	PUC 4-19	12/21/2017	1/11/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology	
COMMISSION SET 4	PUC 4-20	12/21/2017	1/9/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology	
DIVISION SET 4						
DIVISION SET 4	DIVISION 4-1	1/2/2018	1/12/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-2	1/2/2018	1/12/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-3	1/2/2018	1/16/2018	Robert Hevert	Cost of Capital	
DIVISION SET 4	DIVISION 4-4	1/2/2018	1/12/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-5	1/2/2018	1/20/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-6	1/2/2018	1/20/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-7	1/2/2018	1/12/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-8	1/2/2018	1/12/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-9	1/2/2018	1/12/2018	Robert Hevert	Cost of Capital	
DIVISION SET 4	DIVISION 4-10	1/2/2018	1/16/2018	Robert Hevert	Cost of Capital	
DIVISION SET 4	DIVISION 4-11	1/2/2018	1/12/2018	Robert Hevert	Cost of Capital	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 4	DIVISION 4-12	1/2/2018	1/12/2018	Robert Hevert	Cost of Capital	
DIVISION SET 4	DIVISION 4-13	1/2/2018	1/16/2018	Jody Allison	Cost of Capital	
DIVISION SET 4	DIVISION 4-14	1/2/2018	1/16/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-15	1/2/2018	1/12/2018	Robert Hevert	Cost of Capital	
DIVISION SET 4	DIVISION 4-16	1/2/2018	1/16/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 4	DIVISION 4-17	1/2/2018	1/12/2018	Robert Hevert	Cost of Capital	
DIVISION SET 4	DIVISION 4-18	1/2/2018	1/20/2018	Robert Hevert	Cost of Capital	
DIVISION SET 4	DIVISION 4-19	1/2/2018	1/20/2018	Joshua Nowak, Melissa Little	Cost of Capital	
DIVISION SET 4	DIVISION 4-20	1/2/2018	1/12/2018	Joshua Nowak	Cost of Capital	
DIVISION SET 5						
DIVISION SET 5	DIVISION 5-1	1/3/2018	1/23/2018	Robert Sheridan	Benefit-Cost Analysis	Attachment 5-1-1 Attachment 5-1-2
DIVISION SET 5	DIVISION 5-2	1/3/2018	1/18/2018	Carlos Nouel	Benefit-Cost Analysis	
DIVISION SET 5	DIVISION 5-3	1/3/2018	1/22/2018	Robert Sheridan	Benefit-Cost Analysis	
DIVISION SET 5	DIVISION 5-3 SUPPLEMENTAL	1/3/2018	3/5/2018	Robert Sheridan	Benefit-Cost Analysis	
DIVISION SET 5	DIVISION 5-4	1/3/2018	1/17/2018	Robert Sheridan	Benefit-Cost Analysis	
DIVISION SET 5	DIVISION 5-4 SUPPLEMENTAL	1/3/2018	3/5/2018	Robert Sheridan	Benefit-Cost Analysis	
DIVISION SET 5	DIVISION 5-5	1/3/2018	1/21/2018	Robert Sheridan	Benefit-Cost Analysis	
DIVISION SET 5	DIVISION 5-6	1/3/2018	1/17/2018	Melissa Little, Sonny Anand	PST Tracker	
DIVISION SET 5	DIVISION 5-7	1/3/2018	1/17/2018	Melissa Little, Sonny Anand	PST Tracker	
DIVISION SET 5	DIVISION 5-8	1/3/2018	1/17/2018	Melissa Little	PST Tracker	
DIVISION SET 5	DIVISION 5-9	1/3/2018	1/17/2018	Melissa Little	PST Tracker	
DIVISION SET 5	DIVISION 5-10	1/3/2018	1/17/2018	Melissa Little, Kayte O'Neill	PST Tracker	
DIVISION SET 5	DIVISION 5-11	1/3/2018	1/23/2018	Kayte O'Neill	PST Tracker	
DIVISION SET 5	DIVISION 5-12	1/3/2018	1/17/2018	Robert Sheridan	Grid Modernization	
DIVISION SET 5	DIVISION 5-13	1/3/2018	1/17/2018	Robert Sheridan	Grid Modernization	
DIVISION SET 5	DIVISION 5-14	1/3/2018	1/17/2018	Robert Sheridan	Grid Modernization	
DIVISION SET 5	DIVISION 5-15	1/3/2018	1/21/2018	John Leana	Advanced Meter Functionality	
DIVISION SET 5	DIVISION 5-16	1/3/2018	1/17/2018	John Leana	Advanced Meter Functionality	
DIVISION SET 5	DIVISION 5-17	1/3/2018	1/17/2018	John Leana	Advanced Meter Functionality	
DIVISION SET 5	DIVISION 5-18	1/3/2018	1/17/2018	John Leana	Advanced Meter Functionality	
DIVISION SET 5	DIVISION 5-19	1/3/2018	1/17/2018	John Leana	Advanced Meter Functionality	
DIVISION SET 5	DIVISION 5-20	1/3/2018	1/17/2018	John Leana	Advanced Meter Functionality	
DIVISION SET 5	DIVISION 5-21	1/3/2018	1/17/2018	Carlos Nouel	Transportation Electrification	
DIVISION SET 5	DIVISION 5-22	1/3/2018	1/18/2018	Carlos Nouel	Transportation Electrification	
DIVISION SET 5	DIVISION 5-23	1/3/2018	1/22/2018	Carlos Nouel	Transportation Electrification	
DIVISION SET 5	DIVISION 5-24	1/3/2018	1/23/2018	Carlos Nouel	Transportation Electrification	
DIVISION SET 5	DIVISION 5-25	1/3/2018	1/22/2018	Carlos Nouel	Transportation Electrification	Response only
DIVISION SET 5	DIVISION 5-26	1/3/2018	1/17/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 5	DIVISION 5-27	1/3/2018	1/17/2018	Carlos Nouel	Energy Storage	
DIVISION SET 5	DIVISION 5-28	1/3/2018	1/22/2018	Carlos Nouel	Income Eligible	
DIVISION SET 5	DIVISION 5-29	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Proposed Capital Efficiency Incentives)	
DIVISION SET 5	DIVISION 5-30	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Proposed Capital Efficiency Incentives)	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 5	DIVISION 5-31	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Proposed Capital Efficiency Incentives)	
DIVISION SET 5	DIVISION 5-32	1/3/2018	1/21/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (System Efficiency PIM)	
DIVISION SET 5	DIVISION 5-33	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (System Efficiency PIM)	
DIVISION SET 5	DIVISION 5-34	1/3/2018	1/22/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (System Efficiency PIM)	
DIVISION SET 5	DIVISION 5-35	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (System Efficiency PIM)	
DIVISION SET 5	DIVISION 5-35 CORRECTED	1/3/2018	1/23/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (System Efficiency PIM)	
DIVISION SET 5	DIVISION 5-36	1/3/2018	1/18/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (System Efficiency PIM)	
DIVISION SET 5	DIVISION 5-37	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (System Efficiency PIM)	
DIVISION SET 5	DIVISION 5-38	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-39	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-39 CORRECTED	1/3/2018	1/22/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-39 2nd CORRECTED	1/3/2018	2/14/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-40	1/3/2018	1/17/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-40 CORRECTED	1/3/2018	2/7/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-41	1/3/2018	1/17/2018	Mackay Miller	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-42	1/3/2018	1/17/2018	Carlos Nouel	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-43	1/3/2018	1/17/2018	Carlos Nouel	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-44	1/3/2018	1/18/2018	Carlos Nouel	Performance Incentives (Distributed Energy Resources)	
DIVISION SET 5	DIVISION 5-45	1/3/2018	1/18/2018	John Leana	Performance Incentives (Network Support Services)	
DIVISION SET 5	DIVISION 5-46	1/3/2018	1/22/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Network Support Services)	
DIVISION SET 5	DIVISION 5-47	1/3/2018	1/22/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Network Support Services)	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 5	DIVISION 5-48	1/3/2018	1/22/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Network Support Services)	
DIVISION SET 5	DIVISION 5-49	1/3/2018	1/23/2018	Meghan McGuinness, Timothy Roughan	Performance Incentives (Network Support Services)	
DIVISION SET 5	DIVISION 5-50	1/3/2018	1/21/2018	Meghan McGuinness, Timothy Roughan	Impact on Policy Goals and Benefits to Customers	
DIVISION SET 5	DIVISION 5-51	1/3/2018	1/18/2018	Meghan McGuinness, Timothy Roughan	Impact on Policy Goals and Benefits to Customers (System Efficiency)	
DIVISION SET 5	DIVISION 5-52	1/3/2018	1/18/2018	Carlos Nouel	Impact on Policy Goals and Benefits to Customers (System Efficiency)	
DIVISION SET 5	DIVISION 5-53	1/3/2018	1/18/2018	Meghan McGuinness, Timothy Roughan	Impact on Policy Goals and Benefits to Customers(Network Support Services)	
DIVISION SET 6						
DIVISION SET 6	DIVISION 6-1	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-2	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-3	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-4	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-5	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-6	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-7	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-8	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-9	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-10	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-11	1/3/2018	1/22/2018	Alfred Amaral	Meters	
DIVISION SET 6	DIVISION 6-12	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-13	1/3/2018	1/23/2018	John Leana, Alfred Amaral	Meters	
DIVISION SET 6	DIVISION 6-14	1/3/2018	1/23/2018	John Leana, Alfred Amaral	Meters	
DIVISION SET 6	DIVISION 6-15	1/3/2018	1/23/2018	John Leana, Alfred Amaral	Meters	
DIVISION SET 6	DIVISION 6-16	1/3/2018	1/23/2018	John Leana, Alfred Amaral	Meters	
DIVISION SET 6	DIVISION 6-17	1/3/2018	1/23/2018	John Leana, Alfred Amaral	Meters	
DIVISION SET 6	DIVISION 6-18	1/3/2018	1/22/2018	John Leana	Meters	
DIVISION SET 6	DIVISION 6-19	1/3/2018	1/23/2018	John Leana	Meters	Attachment 6-19-2 Attachment 6-19-3
COMMISSION SET 5						
COMMISSION SET 5	PUC 5-1	1/5/2018	1/21/2018	Melissa Little	Allocation of Service Company Costs	
COMMISSION SET 5	PUC 5-2	1/5/2018	1/24/2018	Melissa Little	Allocation of Service Company Costs	
COMMISSION SET 5	PUC 5-3	1/5/2018	1/21/2018	Melissa Little	Organization Structure	
COMMISSION SET 5	PUC 5-4	1/5/2018	1/24/2018	Melissa Little	Organization Structure	
COMMISSION SET 5	PUC 5-5	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Geographic Information System (GIS)	
COMMISSION SET 5	PUC 5-6	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Geographic Information System (GIS)	
COMMISSION SET 5	PUC 5-7	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-8	1/5/2018	1/21/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-9	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
COMMISSION SET 5	PUC 5-10	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-11	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-12	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-13	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-14	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-15	1/5/2018	1/21/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-16	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-17	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-18	1/5/2018	1/21/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-19	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-20	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-21	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-22	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-23	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-24	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-25	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-26	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-27	1/5/2018	1/21/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-28	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly, Melissa Little	Gas Business Enablement	
COMMISSION SET 5	PUC 5-29	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-30	1/5/2018	1/25/2018	Alfred Amaral, John Currie	Gas Business Enablement	
COMMISSION SET 5	PUC 5-31	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-32	1/5/2018	1/24/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
COMMISSION SET 5	PUC 5-33	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	Attachment 5-33
DIVISION SET 7						
DIVISION SET 7	DIVISION 7-1	1/5/2018	1/25/2018	Paul Normand	Regarding Gas Costs of Service and Rates	Attachment 7-1
DIVISION SET 7	DIVISION 7-2	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-3	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-4	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-5	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-6	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-7	1/5/2018	1/21/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-8	1/5/2018	1/24/2018	Paul Normand	Regarding Gas Costs of Service and Rates	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 7	DIVISION 7-9	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-10	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-11	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-12	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-13	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-14	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-15	1/5/2018	1/24/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-16	1/5/2018	1/24/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-17	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-18	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-19	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-20	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-21	1/5/2018	1/21/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-22	1/5/2018	1/17/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-23	1/5/2018	1/24/2018	Paul Normand	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-24	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-25	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-26	1/5/2018	1/21/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-27	1/5/2018	1/21/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-28	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-29	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-30	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-31	1/5/2018	1/25/2018	Ann Leary	Regarding Gas Costs of Service and Rates	Attachment 7-31
DIVISION SET 7	DIVISION 7-32	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-33	1/5/2018	1/21/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-34	1/5/2018	1/24/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-35	1/5/2018	1/25/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-36	1/5/2018	1/21/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-37	1/5/2018	1/24/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-38	1/5/2018	1/24/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-39	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-40	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-41	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 7	DIVISION 7-42	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-43	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-44	1/5/2018	1/24/2018	Ann Leary, Stephen A. Caliri, Eric E. Aprigliano	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-45	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-46	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-47	1/5/2018	1/17/2018	Ann Leary	Regarding Gas Costs of Service and Rates	
DIVISION SET 7	DIVISION 7-48	1/5/2018	1/25/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 7	DIVISION 7-49	1/5/2018	1/21/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement Program	
DIVISION SET 8						
DIVISION SET 8	DIVISION 8-1	1/8/2018	1/27/2018	Robert Sheridan	Benefit-Cost Analyses	
DIVISION SET 8	DIVISION 8-2	1/8/2018	1/27/2018	Robert Sheridan	Benefit-Cost Analyses	
DIVISION SET 8	DIVISION 8-3	1/8/2018	1/27/2018	Robert Sheridan	Grid Modernization	
DIVISION SET 8	DIVISION 8-4	1/8/2018	1/28/2018	Robert Sheridan	Grid Modernization	Attachment 8-4-2
DIVISION SET 8	DIVISION 8-5	1/8/2018	1/27/2018	Robert Sheridan	Grid Modernization	
DIVISION SET 8	DIVISION 8-6	1/8/2018	1/27/2018	Robert Sheridan	Grid Modernization	
DIVISION SET 8	DIVISION 8-7	1/8/2018	1/27/2018	Robert Sheridan	Grid Modernization	
DIVISION SET 8	DIVISION 8-8	1/8/2018	1/28/2018	John Leana	AMF	Attachment 8-8
DIVISION SET 8	DIVISION 8-9	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-10	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-11	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-12	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-13	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-14	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-15	1/8/2018	1/27/2018	John Leana	AMF	Attachment 8-15-2
DIVISION SET 8	DIVISION 8-16	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-17	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-18	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-19	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-20	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-21	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-22	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-23	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-24	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-25	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-26	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-27	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-28	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-29	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-30	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-31	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-32	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-33	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-34	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-35	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-36	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-37	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-38	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-39	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-40	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-41	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-42	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-43	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-44	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-45	1/8/2018	1/28/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-46	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-47	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-48	1/8/2018	1/28/2018	John Leana	AMF	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 8	DIVISION 8-49	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-50	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-51	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-52	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-53	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-54	1/8/2018	1/27/2018	John Leana	AMF	
DIVISION SET 8	DIVISION 8-55	1/8/2018	1/27/2018	Melissa Little	PST Provision	
DIVISION SET 8	DIVISION 8-56	1/8/2018	1/28/2018	Melissa Little	PST Provision	
DIVISION SET 8	DIVISION 8-57	1/8/2018	1/28/2018	Kayte O'Neill	PST Provision	
DIVISION SET 8	DIVISION 8-58	1/8/2018	1/28/2018	Kayte O'Neill	PST Provision	
DIVISION SET 8	DIVISION 8-59	1/8/2018	1/28/2018	Kayte O'Neill	PST Provision	
DIVISION SET 8	DIVISION 8-60	1/8/2018	1/27/2018	Melissa Little	Revenue Requirements	
DIVISION SET 8	DIVISION 8-61	1/8/2018	1/27/2018	Melissa Little	Revenue Requirements	
DIVISION SET 8	DIVISION 8-62	1/8/2018	1/27/2018	Melissa Little	Revenue Requirements	
DIVISION SET 9						
DIVISION SET 9	DIVISION 9-1	1/11/2018	1/31/2018	Melissa Little	Revenue Requirement	
DIVISION SET 9	DIVISION 9-2	1/11/2018	1/30/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 9	DIVISION 9-3	1/11/2018	1/31/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 9	DIVISION 9-4	1/11/2018	1/30/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 9	DIVISION 9-5	1/11/2018	1/31/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	Attachment 9-5-4
DIVISION SET 9	DIVISION 9-6	1/11/2018	1/31/2018	Maureen Heaphy, Melissa Little	Labor Expenses	
DIVISION SET 9	DIVISION 9-7	1/11/2018	1/30/2018	Raymond Rosario, Alfred Amaral	Labor Expenses	
DIVISION SET 9	DIVISION 9-8	1/11/2018	1/30/2018	Raymond Rosario, Alfred Amaral, Ryan Constable	Labor Expenses	
DIVISION SET 9	DIVISION 9-9	1/11/2018	1/30/2018	Melissa Little	Labor Expenses	
DIVISION SET 9	DIVISION 9-10	1/11/2018	2/1/2018	Melissa Little	Labor Expenses	
DIVISION SET 9	DIVISION 9-11	1/11/2018	2/7/2018	Melissa Little	Labor Expenses	
DIVISION SET 9	DIVISION 9-12	1/11/2018	1/31/2018	Melissa Little	Uninsured Claims	
DIVISION SET 9	DIVISION 9-13	1/11/2018	1/31/2018	Melissa Little	Uninsured Claims	
DIVISION SET 9	DIVISION 9-14	1/11/2018	1/30/2018	Melissa Little	Uncollectable Accounts	
DIVISION SET 9	DIVISION 9-15	1/11/2018	1/30/2018	Raymond Rosario	Electric and Gas Operations	
DIVISION SET 9	DIVISION 9-16	1/11/2018	1/31/2018	John Isberg	Customer Affordability Program	
DIVISION SET 9	DIVISION 9-17	1/11/2018	1/30/2018	John Isberg	Customer Affordability Program	
DIVISION SET 9	DIVISION 9-18	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-19	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-20	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-21	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-22	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-23	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-24	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-25	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 9	DIVISION 9-26	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-27	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-28	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-29	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-30	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-31	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-32	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-33	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-34	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-35	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-36	1/11/2018	1/31/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 9	DIVISION 9-37	1/11/2018	1/31/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 9	DIVISION 9-38	1/11/2018	1/21/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 9	DIVISION 9-39	1/11/2018	1/21/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 9	DIVISION 9-40	1/11/2018	1/21/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 9	DIVISION 9-41	1/11/2018	1/21/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 9	DIVISION 9-42	1/11/2018	1/21/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 9	DIVISION 9-43	1/11/2018	1/21/2018	Howard Gorman	Cost of Service & Rate Design	
Department of the Navy						
DON SET 1	DON 1-1	1/11/2018	2/1/2018	Robert B. Hevert, Joseph F. Gredder, Theodore E. Poe Jr, Raymond J Rosario, Alfred Amaral, Ryan M Constable, John F Isberg, Ned W Allis, Melissa A Little, Howard S Gorman, Paul M Normand, Ann E Leary, Scott M McCabe	Workpapers	
DON SET 1	DON 1-2	1/11/2018	2/1/2018	Howard Gorman	RateDesign	
DON SET 1	DON 1-3	1/11/2018	**WITHDRAWN**	**on JANUARY 31, 2018**		
DON SET 1	DON 1-4	1/11/2018	2/1/2018	Timothy Roughan	DG Programs	
DON SET 1	DON 1-5	1/11/2018	2/1/2018	Timothy Roughan	Combined Heat and Power Incentives	
DIVISION SET 10						
DIVISION SET 10	DIVISION 10-1	1/12/2018	2/2/2018	Melissa Little	PST Factor	
DIVISION SET 10	DIVISION 10-2	1/12/2018	2/2/2018	Carlos Nouel	PST Initiative Benefit-Cost Analyses	
DIVISION SET 10	DIVISION 10-3	1/12/2018	1/30/2018	Carlos Nouel	PST Initiative Benefit-Cost Analyses	
DIVISION SET 10	DIVISION 10-4	1/12/2018	2/2/2018	Carlos Nouel	PST Initiative Benefit-Cost Analyses	
DIVISION SET 10	DIVISION 10-5	1/12/2018	2/2/2018	Carlos Nouel	PST Initiative Benefit-Cost Analyses	
DIVISION SET 10	DIVISION 10-6	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 10	DIVISION 10-7	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-8	1/12/2018	2/2/2018	Carlos Nouel	Performance Incentives	
DIVISION SET 10	DIVISION 10-9	1/12/2018	1/30/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-10	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-11	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-12	1/12/2018	1/30/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-13	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-14	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-15	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-16	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-17	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-18	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-19	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-20	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-21	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-22	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-23	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-24	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-25	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 10	DIVISION 10-26	1/12/2018	2/2/2018	Timothy Roughan, Meghan McGuinness	Performance Incentives	
DIVISION SET 11						
DIVISION SET 11	DIVISION 11-1	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-2	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-3	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-4	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-5	1/16/2018	2/5/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-6	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-7	1/16/2018	2/5/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-8	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-9	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-10	1/16/2018	2/2/2018	Melissa Little, Jody Allison	Revenue Requirements	
DIVISION SET 11	DIVISION 11-11	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 11	DIVISION 11-12	1/16/2018	2/2/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Revenue Requirements	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 11	DIVISION 11-13	1/16/2018	2/2/2018	Melissa Little	Revenue Requirements	
DIVISION SET 12						
DIVISION SET 12	DIVISION 12-1	1/18/2018	2/7/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-2	1/18/2018	2/6/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-3	1/18/2018	2/6/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-4	1/18/2018	2/6/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-5	1/18/2018	2/7/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-6	1/18/2018	2/7/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-7	1/18/2018	2/7/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-8	1/18/2018	2/7/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-9	1/18/2018	2/7/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-10	1/18/2018	2/7/2018	Anthony Johnston, Christopher Connolly, Melissa Little	Gas Business Enablement	
DIVISION SET 12	DIVISION 12-11	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 12	DIVISION 12-12	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 12	DIVISION 12-13	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 12	DIVISION 12-14	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 12	DIVISION 12-15	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-16	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-17	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-18	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-19	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-20	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-21	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-22	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-23	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-24	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 12	DIVISION 12-25	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-26	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-27	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-28	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-29	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-30	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-31	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-32	1/18/2018	2/7/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 12	DIVISION 12-33	1/18/2018	2/6/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Technology Modernization Program	
DIVISION SET 13						
DIVISION SET 13	DIVISION 13-1	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-2	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-3	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-4	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-5	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-6	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-7	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-8	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	
DIVISION SET 13	DIVISION 13-9	1/18/2018	2/6/2018	Timothy Roughan, Meghan McGuinness	Peak Demand Reduction	Attachment 13-9-1 through Attachment 13-9-14
DIVISION SET 14						
DIVISION SET 14	DIVISION 14-1	1/22/2018	2/10/2018	Jody Allison	Customer Disconnections	
DIVISION SET 14	DIVISION 14-2	1/22/2018	2/10/2018	Jody Allison	Customer Disconnections	
DIVISION SET 14	DIVISION 14-3	1/22/2018	2/11/2018	Jody Allison	Customer Disconnections	
DIVISION SET 14	DIVISION 14-4	1/22/2018	2/10/2018	Jody Allison	Levelized Billing	
DIVISION SET 14	DIVISION 14-5	1/22/2018	2/10/2018	Jody Allison	Levelized Billing	
DIVISION SET 14	DIVISION 14-6	1/22/2018	2/10/2018	Jody Allison	Levelized Billing	
DIVISION SET 14	DIVISION 14-7	1/22/2018	2/10/2018	Jody Allison	Levelized Billing	
DIVISION SET 14	DIVISION 14-8	1/22/2018	2/10/2018	Jody Allison	Levelized Billing	
DIVISION SET 14	DIVISION 14-9	1/22/2018	2/12/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-10	1/22/2018	2/10/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-11	1/22/2018	2/10/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-12	1/22/2018	2/10/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-13	1/22/2018	2/10/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-14	1/22/2018	2/10/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-15	1/22/2018	2/10/2018	Jody Allison	Arrearages	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 14	DIVISION 14-16	1/22/2018	2/10/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-17	1/22/2018	2/11/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-18	1/22/2018	2/11/2018	Jody Allison	Arrearages	
DIVISION SET 14	DIVISION 14-19	1/22/2018	2/11/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-20	1/22/2018	2/11/2018	John Isberg	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-21	1/22/2018	2/11/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-22	1/22/2018	2/10/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-23	1/22/2018	2/10/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-24	1/22/2018	2/11/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-25	1/22/2018	2/10/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-26	1/22/2018	2/11/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-27	1/22/2018	2/11/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-28	1/22/2018	2/10/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-29	1/22/2018	2/11/2018	Jody Allison	Customer Studies & Collections	Attachment 3 through Attachment 6
DIVISION SET 14	DIVISION 14-30	1/22/2018	2/10/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-31	1/22/2018	2/10/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-32	1/22/2018	2/10/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-33	1/22/2018	2/11/2018	Jody Allison	Customer Studies & Collections	
DIVISION SET 14	DIVISION 14-34	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-35	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-36	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-37	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-38	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-39	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-40	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-41	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-42	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-43	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-44	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-45	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-46	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-47	1/22/2018	2/10/2018	John Isberg	Customer Classifications	
DIVISION SET 14	DIVISION 14-48	1/22/2018	2/10/2018	Timothy Roughan	Customer Classifications	
DIVISION SET 14	DIVISION 14-49	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-50	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-51	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 14	DIVISION 14-52	1/22/2018	2/10/2018	Jody Allison	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-53	1/22/2018	2/10/2018	Jody Allison	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-54	1/22/2018	2/10/2018	Jody Allison	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-55	1/22/2018	2/10/2018	Jody Allison	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-56	1/22/2018	2/11/2018	Jody Allison	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-57	1/22/2018	2/10/2018	Jody Allison	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-58	1/22/2018	2/10/2018	John Isberg	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-59	1/22/2018	2/10/2018	John Isberg	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-60	1/22/2018	2/10/2018	John Isberg	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-61	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-62	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-63	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-64	1/22/2018	2/10/2018	John Isberg	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-65	1/22/2018	2/10/2018	John Isberg	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-66	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-67	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-68	1/22/2018	2/10/2018	John Isberg	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-69	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-70	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-71	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-72	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-73	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-74	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-75	1/22/2018	2/10/2018	Jody Allison	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-76	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 14	DIVISION 14-77	1/22/2018	2/10/2018	Scott McCabe	A-60 Rate Class	
DIVISION SET 15						
DIVISION SET 15	DIVISION 15-1	1/23/2018	2/9/2018	Melissa Little, John Currie	Revenue Requirements	
DIVISION SET 15	DIVISION 15-2	1/23/2018	2/9/2018	Melissa Little, John Currie	Revenue Requirements	
DIVISION SET 15	DIVISION 15-3	1/23/2018	2/9/2018	Melissa Little, John Currie	Revenue Requirements	
DIVISION SET 15	DIVISION 15-4	1/23/2018	2/9/2018	Melissa Little, John Currie	Revenue Requirements	
DIVISION SET 15	DIVISION 15-5	1/23/2018	2/9/2018	Melissa Little, John Currie	Revenue Requirements	
DIVISION SET 15	DIVISION 15-6	1/23/2018	2/9/2018	Melissa Little, John Currie	Revenue Requirements	
DIVISION SET 16						
DIVISION SET 16	DIVISION 16-1	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-2	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-3	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-4	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-5	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-6	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-7	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-8	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-9	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-10	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-11	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-12	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-13	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-14	1/25/2018	2/14/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-15	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-16	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-17	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-18	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-19	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-20	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-21	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-22	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-23	1/25/2018	2/13/2018	Mackay Miller	Electric Heat Initiative	
DIVISION SET 16	DIVISION 16-24	1/25/2018	2/13/2018	John Currie, Melissa Little	Electric Heat Initiative	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 16	DIVISION 16-25	1/25/2018	2/13/2018	Melissa Little	Service Company ROE	
DIVISION SET 16	DIVISION 16-26	1/25/2018	2/13/2018	Melissa Little	Gas Business Enablement Program	
DIVISION SET 17						
DIVISION SET 17	DIVISION 17-1	1/26/2018	2/11/2018	Scott McCabe, Ann Leary	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-2	1/26/2018	2/11/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-3	1/26/2018	2/11/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-4	1/26/2018	2/11/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-5	1/26/2018	2/11/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-6	1/26/2018	2/11/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-7	1/26/2018	2/11/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-8	1/26/2018	2/11/2018	Howard Gorman	Cost of Service & Rate Design	
DIVISION SET 17	DIVISION 17-9	1/26/2018	2/15/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 17	DIVISION 17-10	1/26/2018	2/14/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 17	DIVISION 17-11	1/26/2018	2/14/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 17	DIVISION 17-12	1/26/2018	2/14/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement	
DIVISION SET 17	DIVISION 17-13	1/26/2018	2/14/2018	Melissa Little	Gas Business Enablement	
DIVISION SET 18						
DIVISION SET 18	DIVISION 18-1	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-2	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-3	1/29/2018	2/16/2018	Ned W. Allis, Melissa A. Little	Depreciation Study	
DIVISION SET 18	DIVISION 18-4	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-5	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-6	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-7	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-8	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-9	1/29/2018	2/15/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-10	1/29/2018	2/16/2018	Ned W. Allis, Melissa A. Little	Depreciation Study	
DIVISION SET 18	DIVISION 18-11	1/29/2018	2/16/2018	Ned W. Allis, Melissa A. Little	Depreciation Study	
DIVISION SET 18	DIVISION 18-12	1/29/2018	2/16/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-13	1/29/2018	2/16/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-14	1/29/2018	2/26/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-15	1/29/2018	2/26/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-16	1/29/2018	2/26/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-17	1/29/2018	2/16/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-18	1/29/2018	2/16/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-19	1/29/2018	2/16/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-20	1/29/2018	2/16/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 18	DIVISION 18-21	1/29/2018	2/16/2018	Ned W. Allis	Depreciation Study	
DIVISION SET 19						
DIVISION SET 19	DIVISION 19-1	1/29/2018	2/14/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-2	1/29/2018	2/14/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-3	1/29/2018	2/14/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-4	1/29/2018	2/14/2018	Robert Sheridan	Power Sector Transformation	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 19	DIVISION 19-5	1/29/2018	2/14/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-6	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-7	1/29/2018	2/16/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-8	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-9	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-10	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-11	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-12	1/29/2018	2/16/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-13	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-14	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-15	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-16	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-17	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-18	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-19	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-20	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 19	DIVISION 19-21	1/29/2018	2/15/2018	Robert Sheridan	Power Sector Transformation	
DIVISION SET 20						
DIVISION SET 20	DIVISION 20-1	2/1/2018	2/21/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-2	2/1/2018	2/21/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-3	2/1/2018	2/21/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-4	2/1/2018	2/21/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-5	2/1/2018	2/21/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-6	2/1/2018	2/22/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-7	2/1/2018	2/21/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-8	2/1/2018	2/28/2018	Melissa Little	Revenue Requirements	
DIVISION SET 20	DIVISION 20-9	2/1/2018	2/21/2018	Melissa Little	Revenue Requirements	
DIVISION SET 21						
DIVISION SET 21	DIVISION 21-1	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-2	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-3	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-4	2/2/2018	2/22/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-5	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-6	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-7	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-8	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-9	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-10	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-11	2/2/2018	2/23/2018	Melissa Little	Finances	
DIVISION SET 21	DIVISION 21-12	2/2/2018	2/23/2018	Alfred Amaral	Personnel	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 21	DIVISION 21-13	2/2/2018	2/22/2018	Raymond Rosario, Alfred Amaral, Ryan Constable	Personnel	
DIVISION SET 21	DIVISION 21-14	2/2/2018	2/22/2018	Alfred Amaral	Personnel	
DIVISION SET 21	DIVISION 21-15	2/2/2018	2/22/2018	Melissa Little	Personnel	
DIVISION SET 21	DIVISION 21-16	2/2/2018	2/22/2018	Raymond Rosario, Ryan Constable	Personnel	
DIVISION SET 21	DIVISION 21-17	2/2/2018	2/22/2018	Melissa Little	Personnel	
DIVISION SET 21	DIVISION 21-18	2/2/2018	2/22/2018	Melissa Little	Personnel	
DIVISION SET 21	DIVISION 21-19	2/2/2018	2/22/2018	John Isberg	Customer Affordability Program	
DIVISION SET 21	DIVISION 21-20	2/2/2018	2/22/2018	Anthony Johnston, Christopher Connolly	Gas Business Enablement and Technology	
DIVISION SET 21	DIVISION 21-21	2/2/2018	2/11/2018	Howard Gorman	Cost of Service	
DIVISION SET 21	DIVISION 21-22	2/2/2018	2/14/2018	Howard Gorman	Rate Design and Bill Impacts	
DIVISION SET 21	DIVISION 21-23	2/2/2018	2/14/2018	Howard Gorman	Rate Design and Bill Impacts	
DIVISION SET 21	DIVISION 21-24	2/2/2018	2/11/2018	Howard Gorman	Rate Design and Bill Impacts	
DIVISION SET 21	DIVISION 21-25	2/2/2018	2/11/2018	Howard Gorman	Rate Design and Bill Impacts	
DIVISION SET 21	DIVISION 21-26	2/2/2018	2/11/2018	Howard Gorman	Rate Design and Bill Impacts	
DIVISION SET 22						
DIVISION SET 22	DIVISION 22-1	2/8/2018	2/26/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-2	2/8/2018	2/26/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-3	2/8/2018	3/1/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-4	2/8/2018	2/26/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-5	2/8/2018	2/26/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-6	2/8/2018	2/28/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-7	2/8/2018	2/26/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-8	2/8/2018	2/28/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 22	DIVISION 22-9	2/8/2018	2/26/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty	Service Company Rents	
DIVISION SET 23						
DIVISION SET 23	DIVISION 23-1	2/12/2018	3/1/2018	John Leana	AMI Tech Session	
DIVISION SET 23	DIVISION 23-2	2/12/2018	3/1/2018	John Leana	AMI Tech Session	
DIVISION SET 23	DIVISION 23-3	2/12/2018	3/1/2018	John Leana	AMI Tech Session	
DIVISION SET 23	DIVISION 23-4	2/12/2018	3/1/2018	John Leana	AMI Tech Session	
DIVISION SET 23	DIVISION 23-5	2/12/2018	3/1/2018	John Leana	AMI Tech Session	
DIVISION SET 23	DIVISION 23-6	2/12/2018	3/1/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty, John Leana	AMI Tech Session	
DIVISION SET 23	DIVISION 23-7	2/12/2018	3/1/2018	John Gilbert, Daniel DeMauro, Mukund Ravipaty, John Leana	AMI Tech Session	
DIVISION SET 24						

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 24	DIVISION 24-1	2/16/2018	*Pending*		Power Sector Transformation	
DIVISION SET 24	DIVISION 24-2	2/16/2018	3/5/2018	Kayte O'Neill	Power Sector Transformation	
DIVISION SET 24	DIVISION 24-3	2/16/2018	*Pending*		New York Gas Enablement Settlement	
DIVISION SET 24	DIVISION 24-4	2/16/2018	*Pending*		New York Gas Enablement Settlement	
DIVISION SET 24	DIVISION 24-5	2/16/2018	*Pending*		New York Gas Enablement Settlement	
DIVISION SET 24	DIVISION 24-6	2/16/2018	3/5/2018	Melissa Little	New York Gas Enablement Settlement	
DIVISION SET 24	DIVISION 24-7	2/16/2018	3/5/2018	Robert Sheridan	Feeder Monitoring Proposal	
DIVISION SET 24	DIVISION 24-8	2/16/2018	3/5/2018	Robert Sheridan	Feeder Monitoring Proposal	
DIVISION SET 24	DIVISION 24-9	2/16/2018	*Pending*		Feeder Monitoring Proposal	
DIVISION SET 24	DIVISION 24-10	2/16/2018	3/5/2018	Robert Sheridan	System Data Portal	
DIVISION SET 24	DIVISION 24-11	2/16/2018	3/5/2018	Robert Sheridan	Grid Modernization Activities of the Company and Affiliates	
DIVISION SET 24	DIVISION 24-12	2/16/2018	*Pending*		Grid Modernization Activities of the Company and Affiliates	
DIVISION SET 25						
DIVISION SET 25	DIVISION 25-1	2/20/2018	*Pending*		Performance Incentive Mechanisms	
DIVISION SET 25	DIVISION 25-2	2/20/2018	*Pending*		Performance Incentive Mechanisms	
DIVISION SET 25	DIVISION 25-3	2/20/2018	*Pending*		Performance Incentive Mechanisms	
DIVISION SET 25	DIVISION 25-4	2/20/2018	*Pending*		Performance Incentive Mechanisms	
DIVISION SET 25	DIVISION 25-5	2/20/2018	*Pending*		Annual Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-6	2/20/2018	*Pending*		Annual Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-7	2/20/2018	*Pending*		Annual Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-8	2/20/2018	*Pending*		Annual Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-9	2/20/2018	*Pending*		Annual Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-10	2/20/2018	*Pending*		Annual Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-11	2/20/2018	*Pending*		Annual Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-12	2/20/2018	*Pending*		Monthly Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-13	2/20/2018	*Pending*		Monthly Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-14	2/20/2018	*Pending*		Monthly Peak Demand Reduction PIM	
DIVISION SET 25	DIVISION 25-15	2/20/2018	*Pending*		Demand Responses PIMs	

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	CONFIDENTIAL ATTACHMENT
DIVISION SET 25	DIVISION 25-16	2/20/2018	*Pending*		Demand Responses PIMs	
DIVISION SET 25	DIVISION 25-17	2/20/2018	*Pending*		DG-Friendly Substation Transformers PIM	
DIVISION SET 25	DIVISION 25-18	2/20/2018	*Pending*		Electric Heat PIM	
DIVISION SET 25	DIVISION 25-19	2/20/2018	*Pending*		Electric Heat PIM	
DIVISION SET 25	DIVISION 25-20	2/20/2018	*Pending*		Electric Heat PIM	
DIVISION SET 25	DIVISION 25-21	2/20/2018	*Pending*		Electric Heat PIM	
DIVISION SET 25	DIVISION 25-22	2/20/2018	*Pending*		Electric Heat PIM	
DIVISION SET 25	DIVISION 25-23	2/20/2018	*Pending*		Electric Heat PIM	
DIVISION SET 25	DIVISION 25-24	2/20/2018	*Pending*		Electric Heat PIM	
WAL-MART SET 1						
WAL-MART SET 1	WALMART 1-1	2/21/2018	3/5/2018	Howard Gorman	Performance Incentive Mechanisms	

Fifth Set of Data Requests in Docket 4770
From the Division of Public Utilities to National Grid
January 3, 2018

Benefit-Cost Analyses

5-1. For each benefit-cost analysis included in the rate case filing, please provide all workpapers, workbooks, and calculations in machine-readable format with formulas intact.

Response can be found in Book 1 on Bates page(s) 1-4.

5-2. For each benefit-cost analysis included in the rate case filing, please describe each methodology or assumption that is different from the methodologies and assumptions used by the Company when modeling the cost-effectiveness of its energy efficiency programs.

Response can be found in Book 1 on Bates page(s) 5-7.

5-3. For each benefit-cost analysis included in the rate case filing, please use a societal discount rate of 3.0% (in real terms). Please provide all workpapers, workbooks, and calculations in machine-readable format with formulas intact.

Response can be found in Book 1 on Bates page(s) 8-75.

Response can be found in Supplemental Book 1 on Bates page(s) 1-73

5-4. For each benefit-cost analysis included in the rate case filing, please use a discount rate equal to the discount rate that is currently used for modeling the cost-effectiveness of the Company's energy efficiency programs. Please provide all workpapers, workbooks, and calculations in machine-readable format with formulas intact.

Response can be found in Book 1 on Bates page(s) 76.

Response can be found in Supplemental Book 1 on Bates page(s) 74-78

5-5. With regard to PST Book 1, Appendix 2.2 on Economic Development, please provide all documentation, workbooks, and workpapers used for this analysis, in machine-readable format with formulas intact.

Response can be found in Book 1 on Bates page(s) 77-88.

PST Tracker

5-6. With regard to the most recent ISR filing submitted by the Company, what portion of the Company's total annual capital expenditures were recovered through the ISR relative to other ratemaking mechanisms. Please provide the actual ISR capital expenditures and the actual non-ISR capital expenditures, as well as the proportions.

Response can be found in Book 1 on Bates page(s) 89.

5-7. With regard to the most recent ISR filing submitted by the Company, what portion of the Company's total annual non-capital expenditures were recovered through the ISR relative to other ratemaking mechanisms. Please provide the actual ISR non-capital expenditures and the actual non-ISR non-capital expenditures, as well as the proportions.

Response can be found in Book 1 on Bates page(s) 90.

5-8. Please describe how the regulatory review of the PST Factor and the PST Reconciliation Factor would differ from the regulatory review of the ISR, in terms of timing, stakeholder input, and related procedures. Does the Company intend to coordinate or synchronize the two review processes?

Response can be found in Book 1 on Bates page(s) 91-92.

5-9. Please describe how the recovery of the PST costs would differ from the recovery of costs reviewed through the ISR?

Response can be found in Book 1 on Bates page(s) 93.

5-10. Please explain why the Company does not simply submit all PST costs to the ISR review, and recover all PST costs through the ISR process, instead of creating the PST Factor and the PST Reconciliation Factor.

Response can be found in Book 1 on Bates page(s) 94-95.

5-11. Please explain why the Company did not request the inclusion of the Power Sector Transformation costs in base rates under a multi-year rate plan?

Response can be found in Book 1 on Bates page(s) 96.

Grid Modernization

5-12. Refer to Schedule PST-1, Chapter 3, pages 4-5.

a. Please provide the results of the VVO/CVR pilot project.

b. Please provide the estimated savings on the additional 40 feeders.

Response can be found in Book 1 on Bates page(s) 97-129.

5-13. Refer to Schedule PST-1, Chapter 3, page 4 regarding the power flow analysis to perform long-term system planning. Please provide the Company's most recent long-term system plan.

Response can be found in Book 1 on Bates page(s) 130.

5-14. Refer to Schedule PST-1, Chapter 3, page 7 regarding the system data portal.

a. Please describe the methodology for identifying the most advantageous locations for DERs, and whether this methodology will include an estimate of locational avoided costs.

b. Please provide a link to the similar system data portal deployed in New York and any documents that describe the additional functionality planned or under development.

Response can be found in Book 1 on Bates page(s) 131-132.

Advanced Meter Functionality

5-15. Refer to page 1 of Chapter 4 – AMF in Schedule PST-1, in which the customer service enhancements are described as "including notifications about changes to consumption patterns mid-month that give customers an opportunity to take action before the end of the billing cycle." Please provide the average load profile of a) Income Eligible customers and b) non-Income Eligible customers for the last five calendar years. Please provide the the profiles in machine-readable Excel documents.

Response can be found in Book 1 on Bates page(s) 133-158.

5-16. Please provide the number of residential and commercial customers by service rate over the last five calendar years.

Response can be found in Book 1 on Bates page(s) 159-165.

5-17. Please provide a list of all energy efficiency, conservation, and demand response programs – collectively, demand-side management (DSM) projects – currently offered by the Company, including the names and brief descriptions of the programs.

Response can be found in Book 1 on Bates page(s) 166-171.

5-18. Please provide a list of all DSM program that are expected to be deployed in the upcoming calendar year.

Response can be found in Book 1 on Bates page(s) 172-178.

5-19. For each current DSM program, please provide the annual number of customers participating in the program, by rate schedule, for each of the past five calendar years.

Response can be found in Book 1 on Bates page(s) 179-181.

5-20. Please provide the number of Income Eligible customers each year for the most recent five calendar years.

Response can be found in Book 1 on Bates page(s) 182.

Transportation Electrification

5-21. Refer to Schedule PST-1, Chapter 5, page 1 regarding company-owned charging stations.

a. Please discuss whether any company-owned charging stations are operated by third-party vendors.

b. Please identify whether the site host is the customer of record for each charging station, or whether the Company is the customer of record.

c. Please describe whether and how EV drivers pay to use the station, and whether payment is on a time basis, kWh basis, or some other basis.

d. Please provide the date of installation for each station.

e. Please provide data showing the utilization of each station, and the hours during which the stations are used.

f. Please provide a map of the locations of the Company's charging stations.

g. Please describe how the decision regarding where to locate stations is made.

Response can be found in Book 1 on Bates page(s) 183-188.

5-22. Refer to Schedule PST-1, Chapter 5, page 1 regarding public charging stations needed.

a. Please provide the number of EVs registered in Rhode Island for each of the past 5 years.

b. Has the Company estimated how many public charging stations will be necessary to support the 40-fold growth in EV adoption under the ZEV Draft Plan? If yes, please provide such estimates.

c. Please provide any data or analyses that the Company has in its possession regarding the relationship between EV adoption and charging station availability.

Response can be found in Book 2 on Bates page(s) 1-248.

5-23. Refer to Schedule PST-1, Chapter 5, page 5 regarding the Charging Station Demonstration Program, and construction and ownership by the Company of a new distribution service and required electrical infrastructure (such as new electrical panel, conduit, and wiring) at the premises for each charging site.

a. Will the Company install a new distribution service even if it is not needed to support a charging station?

b. Will the host customer be assessed an additional monthly fixed charge for the new distribution service?

c. If a station is not operated by the Company, will a customer be assessed a demand charge (if a demand charge is included in the tariff under which the customer takes service)?

Response can be found in Book 2 on Bates page(s) 249.

5-24. Refer to Schedule PST-1, Chapter 5, page 5 regarding DC fast charging under the Charging Station Demonstration Program.

a. Please describe how the Company determined that DC Fast Charging should be installed at four public locations at the current time.

b. Please provide all data and analysis that the Company has in its possession regarding the utilization of the existing DC fast chargers in Rhode Island.

c. Did the Company consider providing a rate discount equal to the demand charge to encourage third parties to install additional DC Fast Charging stations? If yes, please explain why this approach was not selected.

d. Did the Company consider providing a charging station rebate (or other up-front incentive) to encourage third parties to install additional DC Fast Charging stations? If yes, please explain why this approach was not selected.

Response can be found in Book 2 on Bates page(s) 250-252.

5-25. Refer to Schedule PST-1, Chapter 5, page 8 regarding Discount Pilot for DC Fast Charging Station Accounts.

a. Please confirm that the demand charge will essentially be waived for three years for service for dedicated DC Fast Charging.

b. For each of the existing DC Fast Charging stations, please provide the customer's rate schedule, the customer's total annual bill, the demand charge portion of the total bill, and the load factor. If such information cannot be provided due to confidentiality reasons, please provide the data in as much detail as possible (such as in a histogram with ranges for each category).

c. Will the Company consider a phasing-in of the demand charge once the three-year period is over?

Response can be found in Book 2 on Bates page(s) 253-254.

Electric Heat Initiative

5-26. Refer to Schedule PST-1, Chapter 6. For each of the four Electric Heat Initiative components, please identify whether the component could be implemented through the Company's energy efficiency programs instead of through a separate PST initiative, and what the advantages or disadvantages of doing so would be.

Response can be found in Book 2 on Bates page(s) 255-256.

Energy Storage

5-27. Refer to Schedule PST-1, Chapter 7 regarding energy storage. Please discuss how the Company will evaluate potential locations to maximize quantifiable benefits.

Response can be found in Book 2 on Bates page(s) 257.

Income Eligible

5-28. Refer to Schedule PST-1, Chapter 8 regarding the Company's proposed Solar Program.

a. Please discuss whether the low income bill reductions under the Company's proposed Solar Program would likely be the same, less than, or greater than bill reductions under a comparable investment in the Community Renewables program.

b. Please discuss whether the Company considered additional support for the Community Renewables program instead of the proposed Solar Program. If yes, please discuss the decision to propose the Solar Program rather than investments in the Community Renewables program.

Response can be found in Book 2 on Bates page(s) 258.

Performance Incentives

Proposed Capital Efficiency Incentives

5-29. Regarding the proposed metric for the Complex Capital Projects Capital Cost Incentive:

a. Please explain whether the incentive would apply to all of the projects included in the Company's ISR plan, or only a subset. If only a subset, please explain how such projects would be determined.

b. Please provide portfolios of complex capital projects for FY 2015, 2016, and 2017, including the project names, sizes, and brief descriptions.

c. Please provide baseline estimates of cost for portfolios of complex capital projects for FY 2015, 2016, and 2017.

d. Please provide a list of planned complex capital projects for FY 2018.

Response can be found in Book 2 on Bates page(s) 259-263.

5-30. Please provide the rationale behind the $2.5 million cap on the value of savings that might be retained by the Company from the Complex Capital Projects Capital Cost Incentive.

Response can be found in Book 2 on Bates page(s) 264.

5-31. Please provide information on the per-mile construction costs for previous overhead distribution line projects.

Response can be found in Book 2 on Bates page(s) 265-266.

System Efficiency PIM

5-32. For each of the most recent five years, please provide the portion of total costs that each of the following categories represents: generation capacity (FCM), transmission, distribution, and energy supply. Please provide these costs on a monthly basis, if possible.

Response can be found in Book 2 on Bates page(s) 267-268.

5-33. Refer to Workpaper 9.1 – Peak Demand Reduction Targets.

a. Please provide the Company's internal peak forecast in machine-readable format.

b. Please provide the methodology behind and the input data for the forecast in machine-readable format.

c. Please provide the methodology and calculations for the EE reduction and PV reduction forecasts in machine-readable format.

Response can be found in Book 2 on Bates page(s) 269-286.

5-34. Regarding the proposed metric for the Monthly Transmission Peak Demand Reduction Incentive Mechanism:

a. Please describe the weather-normalization methodology to be used for this PIM and provide a numerical example.

b. Please provide the actual monthly peaks for each of the most recent five years in MW, as well as the date and time of the peak.

c. Please provide the weather-normalized monthly peaks for each of the most recent five years.

d. Please provide the reductions in monthly peaks for each of the most recent five years due to energy efficiency, storage, DG, VVO, and Demand Response. Where possible, please provide the reductions separately, by technology.

e. Please explain how "large new electric loads" is defined.

f. Please provide the additions of "large new electric loads" on the system for each of the past five years, as well as the peak demands at the new large load sites that are coincident with monthly or annual peak load.

Response can be found in Book 3 part 1 on Bates page(s) 1-10.

5-35. Regarding the proposed metric for the Forward Capacity Market Peak Demand Reduction:

a. Please describe the weather-normalization methodology to be used for this PIM and provide a numerical example.

b. Please provide the actual annual peak load for each of the past five years in MW, as well as the date and time of the peak.

c. Please provide the weather-normalized annual peak load for each of the past five years.

d. Please provide the reductions in annual peak load from the past five years due to energy efficiency, storage, DG, VVO, and Demand Response. Where possible, please provide the reductions separately, by technology.

Response can be found in Book 3 part 1 on Bates page(s) 11-20.

5-36. Refer to Workpaper 9.4 – Incentive Benefits, page 2 of 5. Please provide the calculations used to derive the annual capacity benefits from the peak targets (in MW) in as a machine-readable Excel file.

Response can be found in Book 3 part 1 on Bates page(s) 21-23.

5-37. Regarding the EV Off-Peak Charging Rebate Participation incentive mechanism:

a. Please explain how off-peak EV charging will be measured. Will an advanced meter be required, or will the Company rely on a different technology?

b. If the Company will rely on a different technology to measure off-peak charging, please describe the technology, the cost of the technology, and who will bear the cost of purchasing and installing the technology.

c. Please explain how target participation levels will be developed. Will the target participation level be based on a percentage of EV sales in Rhode Island, or some other metric?

Response can be found in Book 3 part 1 on Bates page(s) 24-25.

Distributed Energy Resources

5-38. Regarding DG-Friendly Substation Transformers:

a. Please describe the conditions under which ground fault detection is needed to integrate DG.

b. Please identify the number of substation transformers that currently experience the conditions described in (a).

c. Please identify the number of substation transformers that are projected to experience the conditions described in (a), and when such conditions are expected to first occur.

d. Please provide the number of substation transformers that already have ground fault detection (3V0) installed and are capable of readily accommodating distributed generation.

e. Please provide the number of substation transformers that were installed with ground fault detection (3V0) each year for the past five years.

f. For each substation, please provide the number and capacity (MW) of DG installations, and identify whether the substation already has ground fault detection installed, or when installation is planned.

Response can be found in Book 3 part 1 on Bates page(s) 26-29.

5-39. Regarding the Company's Connected Solutions program:

a. Please provide the average annual number of residential customers participating in the Connected Solutions program for each of the last five years.

b. For each high energy demand event over the last five years, please provide the MW reductions attributed to the Connected Solutions program.

c. Please provide the average kW reduction per high energy demand event per residential customer attributed to the Connected Solutions program.

d. Please provide the program costs by major cost category, exclusive of customer incentives, for each of the past five years.

Response can be found in Book 3 part 1 on Bates page(s) 30-35.

2nd CORRECTED Response can be found on Bates page(s) 1-4.

5-40. Regarding the Company's C&I demand response programs:

a. Please describe each of the Company's C&I demand response programs.

b. Please provide the average annual number of commercial and industrial customers, separately, participating in the Company's C&I demand response programs.

c. Please provide the historical MW capacity enrolled in the Company's C&I demand response programs.

d. Please provide the historical MW reductions achieved via the Company's C&I demand response programs.

e. Please provide the program costs by major cost category, exclusive of customer incentives, for each of the past five years.

f. Are demand reductions attributable to this program included in the Company's baseline forecast of peak demand?

Response can be found in Book 3 part 1 on Bates page(s) 36-38.

CORRECTED Response can be found on Bates page(s) 1-3.

5-41. Regarding the Company's ground source heat pump and equipment incentives being offered under the Electric Heat Initiative:

a. Please provide the annual number of customers, by rate schedule, that have used the Company's ground source heat pump and equipment incentives for the past five years;

b. Please provide the annual CO_2 reductions attributed to the ground source heat pump and equipment incentives for the past five years.

c. Please provide the average per customer CO_2 reductions, by customer class, attributed to the ground source heat pump and equipment incentives for the past five years.

d. Are demand reductions attributable to these programs included in the Company's baseline forecast of peak demand?

Response can be found in Book 3 part 1 on Bates page(s) 39.

5-42. Regarding Electric Vehicles:

a. Please provide the data and calculations used to derive the 2018 – 2021 forecasts for EV registrations in Workpaper 9.3 – Electric Vehicle Targets in machine-readable format.

b. Has the Company or its consultants developed any other forecasts of EV Sales Growth? If yes, please provide such forecasts.

Response can be found in Book 3 part 1 on Bates page(s) 40-56.

5-43. Regarding behind-the-meter storage:

a. Please provide the total MWs of behind-the-meter storage currently installed in National Grid's Rhode Island service territory, by customer class.

b. Please provide the annual incremental MW of installed behind-the-meter storage for the past five years.

c. Please describe how the Company is informed of, and tracks, behind-the-meter storage.

d. Please discuss whether the Company will be rewarded for any additional behind-the-meter storage installed, or only incremental to a baseline forecast of naturally-occurring storage installations.

Response can be found in Book 3 part 1 on Bates page(s) 57.

5-44. Regarding Company-owned storage as described on Schedule PST-1, Chapter 9, page 13:

a. Please identify whether the Company owns any storage that is not "used to support peak reduction or provide other system benefits."

b. Please provide the total MW and MWh of Company-owned storage currently installed.

c. Please provide the annual incremental MW and MWh of Company-owned storage for the past five years.

d. Please provide a list of all planned Company-owned storage projects, including the site, size (in MW and MWh), and expected installation date.

Response can be found in Book 3 part 1 on Bates page(s) 58.

Network Support Services

5-45. Refer to page 175 of the Power Sector Transformation Panel (Book 1 of 3). Please provide examples of customer insights from internal customer research, knowledge gained from Company experience with pilot projects, and industry best practices that will be used in the proposed customer engagement plan under the AMF Customer Engagement and Deployment incentive mechanism.

Response can be found in Book 3 part 1 on Bates page(s) 59-Book 3 part 5 on Bates pages(s) 280.

5-46. Regarding the VVO Pilot Delivery incentive mechanism:

a. Please provide the baseline reduction in energy consumption and peak demand that will be used in the VVO Pilot Delivery incentive mechanism.

b. Please provide all supporting documents for the development of the baseline.

Response can be found in Book 3 part 5 on Bates page(s) 281-286.

5-47. Regarding the Time to Interconnection Service Agreement (ISA) metric:

a. Please provide the average time measured in business days necessary for the Company to provide a customer with an executable ISA (commencing from the data a completed application is received) over all processes for the last five years.

b. Please provide the annual number of ISAs completed for the last five years.

c. Please provide the annual number of ISAs completed within the number of business days allowed by the Interconnection Tariff.

d. Please provide the annual number of ISAs not completed within the number of business days allowed by the Interconnection Tariff.

Response can be found in Book 3 part 5 on Bates page(s) 287-288.

5-48. Regarding the Average Days to System Modification metric:

a. Please provide the average time measured in business days necessary for the Company to complete system modifications (commencing from the date of execution of the ISA) over all processes for the last five years.

b. Please provide the annual number of system modifications completed for the last five years.

c. Please provide the annual number of system modifications completed within the number of business days allowed by the Interconnection Tariff.

d. Please provide the annual number of system modifications not completed within the number of business days allowed by the Interconnection Tariff.

Response can be found in Book 3 part 5 on Bates page(s) 289-290.

5-49. Regarding the Interconnection Support Estimate versus Actual Cost incentive:

a. Please discuss whether the employees developing the actual costs will have access to the cost estimates.

b. If the answer to (a) is yes, please discuss how the Company will mitigate the incentive for an employee to modify the actual cost so that it better matches the estimated cost.

c. Please discuss whether any independent review of the data is contemplated.

Response can be found in Book 3 part 5 on Bates page(s) 291.

Impact on Policy Goals and Benefits to Customers

5-50. Please provide the calculations used to arrive at the Company WACC that is used in Workpaper 9.4 – Incentive Benefits in a machine-readable Excel document.

Response can be found in Book 3 part 5 on Bates page(s) 292-293.

System Efficiency

5-51. Please provide estimates of savings from reduced capacity share that will benefit customers in the years 2020 and 2021 from the Forward Capacity Market Peak Demand Reduction targets.

Response can be found in Book 3 part 5 on Bates page(s) 294-296.

5-52. Please describe the value the EV Off-Peak Charging Rebate is expected to provide in understanding customer response to time-differentiated price signals. Please provide examples of how this understanding will assist the development of time-differentiated price signals via AMF deployment.

Response can be found in Book 3 part 5 on Bates page(s) 297.

Network Support Services

5-53. Refer to Schedule PST-1, Chapter 9, page 21. Please list the system efficiencies that are expected to occur through the combination of AMF and VVO/CVR.

Response can be found in Book 3 part 5 on Bates page(s) 298.

Division 5-3 SUPPLEMENTAL

Request:

For each benefit-cost analysis included in the rate case filing, please use a societal discount rate of 3.0% (in real terms). Please provide all workpapers, workbooks, and calculations in machine-readable format with formulas intact.

Response:

The Company did not re-run the benefit-cost analyses included in its rate case filing using a societal discount rate of 3.0 percent, as the use of such an alternative discount rate will produce misleading results. The use of the Company's weighted average cost of capital (WACC) is the appropriate discount rate for estimating the net present value of the proposed Power Sector Transformation projects, as each represents utility investment and the associated costs to deploy capital and other expenses borne directly by utility customers.[1] The use of a discount rate that is lower than the Company's WACC may inappropriately under-value near term costs and benefits relative to more speculative benefits accrued at the end of the forecast period, potentially resulting in over-estimation of the cost-effectiveness of the proposed investments.

(This response is identical to the Company's response to Division 1-3 in Docket No. 4780).

Supplemental Response:

Please see Attachment DIV 5-3-3 CONFIDENTIAL, Attachment DIV 5-3-4 CONFIDENTIAL, and Attachment DIV 5-3-5. Attachment DIV 5-3-3 CONFIDENTIAL contains the benefit-cost analysis (BCA) of the Company's proposed advanced metering functionality (AMF) deployment proposal for the Rhode Island only implementation program scenario, using an alternative real discount rate of 3.0 percent. Attachment DIV 5-3-4 CONFIDENTIAL contains the BCA of the Company's proposed AMF deployment proposal for the joint Rhode Island and New York Niagara Mohawk Power Corporation (Niagara Mohawk) implementation scenario, using an alternative real discount rate of 3.0 percent.

Attachment DIV 5-3-5 contains the BCAs for the Company's proposed Electric Transportation Initiative, Electric Heat Initiative, Energy Storage Investments, Company-Owned Solar

[1] For more detailed explanations of why the utility WACC is a more appropriate discount rate for evaluating utility investments than a lower societal discount rate, see for example: Reply Comments of the Joint Utilities Regarding Staff White Paper on Benefit-Cost Analysis, State of New York Public Service Commission Case 14-M-0101, September 10, 2015, pp. 21-16 included as Attachment DIV 5-3-1; and Comments of Massachusetts Electric Company d/b/a National Grid in Massachusetts Department of Public Utilities Docket No. D.P.U. 12-76, August 22, 2014, pp. 15-19 included as Attachment DIV 5-3-2.

Facilities, and Income Eligible Rewards Program, using an alternative real discount rate of 3.0 percent.

Please note that the alternative BCAs provided as attachments to this response and the summary of results shown below in Table 1. AMF BCA Summary by Implementation Scenario, Participation and Savings Scenario, and Discount Rate and Table 2. BCA Summary by Investment Category and Discount Rate, as well as the BCA results provided in the Company's supplemental response to Division 5-4, introduce multiple alternative sets of BCA results for each proposed investment into the record in this proceeding. The Company presents these alternative BCA results solely to provide the information requested by the Division of Public Utilities and Carriers, but does not view these requested results as valid or appropriate to determine the best use of customer funds. The Company is prepared to substantiate and defend the validity of the BCA results used by the Company in the proposed Power Sector Transformation Plan, as filed.

Table 1. AMF BCA Summary by Implementation Scenario, Participation and Savings Scenario below compares the Societal Cost Test (SCT) benefit-cost ratios originally filed in the Power Sector Transformation Plan using a real discount rate equal to the Company's after-tax WACC (7.5 percent) to the benefit-cost ratios that result when the alternative real discount rate of 3.0 percent is used. The results are shown for the proposed AMF deployment under the Rhode Island Only and Joint Rhode Island and New York Niagara Mohawk implementation scenarios, as well as under each of the four participation and savings scenarios. Across all scenarios, the use of the alternative 3.0 percent real discount rate increases the SCT benefit-cost ratios by 16 percent to 23 percent relative to the benefit-cost ratios used in the Company's proposal for the Power Sector Transformation Plan.

Table 1. AMF BCA Summary by Implementation Scenario, Participation and Savings Scenario, and Discount Rate

Participation/Savings Scenario		**Scenario 1 Opt-In/ Low Savings**	**Scenario 2 Opt-In/High Savings**	**Scenario 3 Opt-Out/Low Savings**	**Scenario 4 Opt-Out/High Savings**
Implementation Scenario	**Discount Rate**	**SCT Benefit-Cost Ratios**			
Rhode-Island Only	7.5%	0.79	1.07	0.88	1.27
Rhode-Island Only	3.0%	0.92	1.26	1.05	1.54
	% Change	16%	18%	19%	21%
Joint Rhode-Island & NY Niagara Mohawk	7.5%	1.07	1.44	1.19	1.71
Joint Rhode-Island & NY Niagara Mohawk	3.0%	1.26	1.73	1.44	2.11
	% Change	18%	20%	21%	23%

Table 2. BCA Summary by Investment Category and Discount Rate below compares the SCT and Rate Impact Measure (RIM) benefit-cost ratios originally filed in the Power Sector Transformation Plan using a real discount rate equal to the Company's after-tax WACC (7.5 percent) to the benefit-cost ratios that result when the alternative real discount rate of 3.0 percent is used. The results are shown for the proposed Electric Transportation Initiative, Electric Heat Initiative, Energy Storage Investments, Company-Owned Solar Facilities, and Income-Eligible Rewards Program. Across all investment categories, the use of the alternative 3.0 percent real discount rate increases the SCT benefit-cost ratios by 35 percent to 53 percent and increases the RIM benefit-cost ratios by 18 percent to 56 percent, relative to the benefit-cost ratios originally filed in the Power Sector Transformation Plan.

Table 2. BCA Summary by Investment Category and Discount Rate

Cost-Effectiveness Test	SCT Benefit-Cost Ratios			RIM Benefit-Cost Ratios		
Discount Rate	**7.5%**	**3.0%**	**% Change**	**7.5%**	**3.0%**	**% Change**
Investment Category						
Electric Transportation Initiative	1.03	1.57	52%	0.13	0.15	18%
Electric Heat Initiative	1.12	1.60	43%	2.42	3.52	45%
Company-Owned Solar Facilities and Income Eligible Rewards Program	0.85	1.30	53%	0.63	0.98	56%
Energy Storage Investments	0.45	0.61	35%	0.49	0.67	38%

(This response is identical to the Company's supplemental response to Division 1-3 in Docket No. 4780.)

Prepared by or under the supervision of: Robert Sheridan

Janet M. Audunson, P.E., Esq.
Senior Counsel II

September 10, 2015

VIA ELECTRONIC DELIVERY

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

RE: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

Reply Comments of the Joint Utilities Regarding Staff White Paper on Benefit-Cost Analysis

Dear Secretary Burgess:

In response to the Notice Inviting Public Comment on Staff White Paper on Benefit-Cost Analysis issued by the Commission on July 2, 2015 in Case 14-M-0101, Niagara Mohawk Power Corporation d/b/a National Grid, Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation (collectively the "Joint Utilities") hereby submit for filing their Reply Comments.

Respectfully submitted,

By: */s/ Janet M. Audunson*

Janet M. Audunson
Senior Counsel II

Enc.

cc: Denise Gerbsch, DPS Staff, w/enclosure (via electronic mail)
Susan Vercheak, Con Edison, w/enclosure (via electronic mail)
Joseph Hally, Central Hudson, w/enclosure (via electronic mail)
Joseph Syta, NYSEG/RG&E, w/enclosure (via electronic mail)
Catherine Nesser, w/enclosure (via electronic mail)
Pamela Viapiano, w/enclosure (via electronic mail)
Cathy Hughto-Delzer, w/enclosure (via electronic mail)
Peter Zschokke, w/enclosure (via electronic mail)
Stephen Caldwell, w/enclosure (via electronic mail)
Lauri Mancinelli, w/enclosure (via electronic mail)

300 Erie Blvd. West, A-4, Syracuse, New York 13202
T: 315/428-3411 ■ F: 315/401-7891 ■ Janet.Audunson@nationalgrid.com ■ www.nationalgrid.com

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission) in Regard to) Reforming the Energy Vision)	**Case 14-M-0101**

REPLY COMMENTS OF THE JOINT UTILITIES REGARDING STAFF WHITE PAPER ON BENEFIT-COST ANALYSIS

Dated: September 10, 2015
Syracuse, New York

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision	)))	**Case 14-M-0101**

REPLY COMMENTS OF THE JOINT UTILITIES REGARDING STAFF WHITE PAPER ON BENEFIT-COST ANALYSIS

I. INTRODUCTION

In response to the Notice Inviting Public Comment on Staff White Paper on Benefit-Cost Analysis ("BCA White Paper")[1] issued by the New York Public Service Commission (the "Commission") on July 2, 2015 (the "Notice") in the Reforming the Energy Vision Proceeding ("REV"),[2] Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas and Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation (collectively the "Joint Utilities") hereby file their Reply Comments.

II. EXECUTIVE SUMMARY

The Joint Utilities appreciate this opportunity to reply to the initial comments of other parties on the BCA White Paper. As the Joint Utilities and other parties indicated in their initial

[1] Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV Proceeding"), *Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding* (issued July 1, 2015) ("BCA White Paper").

[2] REV Proceeding, *Notice Inviting Public Comment on Staff White Paper on Benefit-Cost Analysis* (issued July 2, 2015) ("Notice"). Subsequently, the deadline for filing initial comments was extended by the Secretary to August 21, 2015 with reply comments due by September 10, 2015. *See* REV Proceeding, *Notice Confirming Extension of Deadline for Public Comment on Staff White Paper on Benefit-Cost Analysis* (issued August 11, 2015).

comments, the Benefit Cost Analysis tests ("BCA" tests) themselves and the overall framework for applying them ("BCA Framework") are critical elements for the cost-effective implementation of REV. In response to the initial comments filed by other parties, the Joint Utilities state that:

1. The primary purpose of the BCA Framework must be that the New York State electric grid continues to provide safe, adequate, and reliable electric service at a reasonable rate to all customers. (Section III.A)
2. When a specific grid need has been identified and specific functionality is required to meet that need, other benefits (*e.g.*, environmental attributes), however desirable, should not be treated as trade-offs or substitutions for that functionality. (Section III.B)
3. DER functionalities and attributes vary. Specific types of DER may only be applicable in certain specific situations. (Section III.B)
4. The Distributor Cost Test ("DCT") as proposed in the Joint Utilities Initial Comments remains the most appropriate BCA test to use for certain applications within REV. A number of practical matters will make it difficult and contentious to use the SCT. (Section IV.A)
5. Should the Commission designate the Societal Cost Test ("SCT") for primary use in REV decision-making and resource selection and determine that costs the utilities and their customers do not avoid should be monetized, rate and/or bill impacts should also be transparently assessed with specificity regarding funding sources. (Section IV.B)
6. The marginal damage cost approach to reflecting environmental externalities in the BCA Framework (Approach 2) is an unsound method to value avoided greenhouse

gas ("GHG") emissions and criteria air pollutants because of the danger of creating multiple conflicting price signals. It is equally unsound to expand the scope of environmental externalities to be considered. (Sections IV.A, C, and E)

7. The Joint Utilities oppose the inclusion and widespread use of non-energy benefits, but if the Commission rules to include them, only non-energy benefits that can be objectively quantified should be considered and only within the SCT (*i.e.*, remove those benefits from the Rate Impact Measure ("RIM"), DCT, and Program Administrator Cost ("PAC) tests). (Sections IV.A and IV.E)
8. If the State desires greater GHG emission reductions from the power sector than what is required under the present RGGI program, the most direct and efficient approach is to work with the other RGGI member states to continue to ratchet down the RGGI emissions cap. The establishment of CO_2 prices outside of RGGI will provide inaccurate price signals to customers and distributed energy resources ("DER") providers and could result in over- or under-investment in DER. (Section IV.C)
9. The appropriate discount rate to be used in the DCT is the utility weighted average cost of capital ("WACC"). The WACC should be used for the SCT as well, because both traditional utility projects and the associated DER selected as part of non-wires alternatives ("NWA") would be funded partially or wholly by the utilities. There is no evidence supporting the concept that the average discount rate for utility customers is at the level implied by the societal rate. In any case, use of a low societal discount rate should be avoided because it places too much weight on assumptions at the end of the forecast period when forecasted benefits and costs are least certain. (Section IV.E)

10. Consistent with the new general principle recommended in the Joint Utilities' Initial Comments that "the process for applying and updating the Benefit Cost Analysis Handbooks ("BCAH") should not be costly or administratively burdensome for any party," the use of sensitivity analyses should be limited to those that are practicable and likely to prove informative to decision-making. (Section V)
11. The Joint Utilities continue to support the filing of the initial BCAH with the Distributed System Implementation Plans ("DSIPs"), currently set as June 30, 2016.[3] The BCAH should establish guidelines and should be updated annually. (Section V)
12. The Joint Utilities will begin developing a common BCAH outline employing the DCT as the economic test for evaluating alternatives to traditional utility projects. (Section V)

III. THRESHOLD CONSIDERATIONS

A. Primary Purpose of BCA

The Joint Utilities agree with those parties that believe an outcome-neutral BCA is required to create a level playing field that selects the most cost-effective grid assets (traditional or DER).[4] To achieve this goal, the BCA test should consider whether a portfolio of DER is cost effective for customers of a de-regulated utility as compared to a traditional utility investment. Environmental and non-energy benefits and other public policy considerations should only be considered after a potential project has successfully passed a BCA test. As discussed below,

---

[3] REV Proceeding, *Notice Extending Deadlines Regarding Filings Related to Distributed System Implementation Plans* (issued September 4, 2015).

[4] *See generally* Benefit-Cost Analysis Comments of the Exelon Companies (August 21, 2015) ("Exelon Companies Comments"), pp. 2-5; *see also* Initial Comments of Multiple Intervenors on "White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding" (August 21, 2015) ("MI Comments"), p. 2; *see also* Initial comments of New York Affordable Reliable Electricity Alliance (August 20, 2015), pp. 1-2.

when these additional factors are considered, the impact on customer rates and bills should also be concurrently evaluated.[5]

This view is consistent with the intent of REV, based on the Commission's original identification of six REV objectives,[6] to maintain and improve the performance and cost-effectiveness of the electric system for customers. Should these objectives not be achieved, it is unlikely that REV will be considered successful by customers, even if, as the Joint Utilities expect and support, REV helps to facilitate reductions in GHG emissions.[7]

It is apparent that many other parties see the primary purpose of the BCA differently. The Advanced Energy Economy Institute, *et al*. ("AEEI") caution that the BCA should not be a barrier to DER, pointing out that BCA "[s]implifications, where needed, should err on the side of achieving REV's key objective of using DER to meet customer and system needs."[8] New York Geothermal Energy Organization would modify the BCA to capture the benefits unique to their technologies.[9]

Many parties would have the Commission direct the Joint Utilities to apply the BCA Framework in a manner that they believe would maximize environmental and other non-energy benefits, with little regard for the cost to customers. For example the New York State

---

[5] The Joint Utilities view this perspective as fully consistent with the use of the DCT.

[6] The six REV objectives are: (1) enhanced customer knowledge and tools to support effective management of total energy bill; (2) market animation and leverage of ratepayer contributions; (3) system-side efficiency; (4) fuel and resource diversity; (5) system reliability and resiliency, and (6) reduction of carbon emissions. REV Proceeding, *Order Instituting Proceeding* (issued April 25, 2014), p. 2. Of these, the Joint Utilities note that three pertain to the grid, two to the customer bill, and one to the environment.

[7] In addition, as noted in the Joint Utilities' Initial Comments, the primary although not the sole users, of the BCA Framework are likely to be the utilities, who are responsible for providing safe, adequate, and reliable electric service to customers at reasonable rates.

[8] Comments on Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding of the Advanced Energy Economy Institute, on behalf of the Advanced Energy Economy (AEE), the Alliance for Clean Energy New York (ACE NY), and the New England Clean Energy Council (August 21, 2015) ("AEEI Comments"), p. 5.

[9] Initial Comments on the 7/1/15 Staff White Paper on Benefit-Cost Analysis from the New York Geothermal Energy Organization (August 21, 2015) ("NY-GEO Comments"), pp. 2-5.

Department of Environmental Conservation ("NYSDEC") is concerned that "if the BCA is not appropriately designed it will not adequately stimulate the energy transition that New York State committed to in the State Energy Plan," as is Acadia Center.[10] As discussed further in Section IV below, a number of parties support the use of the SCT as the BCA test and press for quantification of non-energy benefits and the addition of more non-energy benefits.

These parties see the primary purpose of the BCA and the REV proceeding in general as developing and implementing a policy of maximizing the deployment of DER. They would achieve this by crediting DER with claimed environmental and non-energy benefits sufficient to make DER pass a BCA test and would then presumably seek to convert those benefits to direct payments to DER providers. This suggests adjusting the test to produce the desired outcome rather than allowing the test to determine the outcome. While the motivation of parties advocating this perspective is clear, this skews the results and does not allow for an objective analysis of a potential project. Moreover, there are policies already in place in New York State that address the major environmental externalities from the electricity system and reflect compliance costs in energy prices. Therefore, it is inappropriate to use the BCA as a vehicle to maximize DER penetration through claimed environmental and non-energy benefits.

B. Functionality vs. Other Benefits

Section VII.A of the Joint Utilities' Initial Comments recommends an initial screen to be applied when determining whether traditional utility distribution solutions would be compared to NWA proposals. This step is consistent with a normal resource procurement process, where the proposal is first screened to determine whether it meets the threshold functional performance

---

[10] Comments of New York State Department of Environmental Conservation's Office of Air Resources, Climate Change and Energy and Office of General Counsel (August 21, 2015) ("NYSDEC Comments"), pp. 3-4; Acadia Center Comments on Benefit-Cost Analysis White Paper (August 21, 2015) ("Acadia Center Comments"), p. 2.

requirements, and only then is the proposal subject to some form of cost-effectiveness evaluation. Here, utility distribution solutions would be screened to determine whether they can reasonably be replaced or deferred by DER before NWA proposals would be considered.

It is critical for the Commission and all parties to understand that regardless of bulk power system, environmental, and non-energy benefits, DER can substitute for traditional distribution utility solutions only if they can provide acceptably equivalent functionality. In other words, DER must allow the utility to continue to provide safe, adequate, and reliable service to all customers on the phase, circuit, and substation. In order for DER to operate without impacting safe, adequate, and reliable service, incremental services will be required from utilities with associated costs, which must be considered in the BCA analysis.

In their initial comments, various parties propose grid benefits be taken into account in the BCA tests, including:

- Line loss reduction (Peak Power LLC)[11]
- Optionality, maintaining critical load (New York Battery and Energy Storage Technology Consortium)[12]
- System efficiency improvements, islanding ability, local emergency power (Energy Storage Association)[13]
- Voltage management and power factor improvement, avoided resiliency-specific upgrades such as converting distribution feeders to an underground system, avoided restoration costs, extended equipment lifetimes/deferred replacements due to reduced loading and "wear and tear" (AEEI)[14]
- Reliability, avoided outage costs, resiliency (City of New York)[15]
- Resiliency, reliability, public safety benefits (Exelon Companies)[16]

[11] Comments of Peak Power LLC on Staff White Paper on Benefit-Cost Analysis (August 21, 2015) ("Peak Power Comments"), pp. 5-6.

[12] Comments of New York Battery and Energy Storage Technology Consortium on the Department of Public Service (DPS) Staff White Paper on Benefit-Cost Analysis (August 21, 2015) ("NY-BEST Comments"), pp. 7-8.

[13] Comments of the Energy Storage Association (August 21, 2015), p. 4.

[14] AEEI Comments, pp. 16-19.

[15] Comments of the City of New York On Benefit Cost Analysis Framework (August 21, 2015) ("City of New York Comments"), pp. 4 & 9.

[16] Exelon Companies Comments, p. 8.

- Power quality, reliability, resiliency, avoided operation and maintenance ("O&M") costs (The Alliance for Solar Choice)[17]

At least some of these may be included in defined BCA test benefit categories and, in that context, they should be considered for inclusion in the BCA test. To the extent that data exists to reliably quantify these values and determine that the costs are verifiably avoidable and material, (and to the extent that actual DER performance along these dimensions can be measured and verified at a reasonable cost), the Joint Utilities are prepared to consider inclusion of these components in the BCA tests.

As noted in the Joint Utilities Initial Comments, the BCA tests are initially proposed to be used for screening NWA projects in competitive procurements, where prices will be determined during the competitive procurement process rather than from the results of the BCA Framework application.[18] Therefore, the inclusion of any factors in a BCA test, including those listed above, will not directly determine DER payments.

IV. ECONOMIC CONSIDERATIONS OF BCA TESTS

A. Applicability of the DCT as the BCA Test and Relationship to RIM

As indicated above, several parties support applying the BCA tests in a way that objectively quantifies the marginal benefits and costs of DER compared to traditional utility investments so that the most cost-effective set of resources are pursued to meet distribution

[17] The Alliance for Solar Choice Comments on Staff White Paper on Benefit-Cost Analysis (August 21, 2015) ("TASC Comments"), pp. 10-11.

[18] The Joint Utilities Initial Comments noted that further work would be necessary to determine how best to use the BCA tests to develop tariffs. Further work would also be necessary to determine how best to factor these benefits into such tariffs, if they are included in the BCA tests.

system needs.[19] Only the Joint Utilities proposal to apply the DCT as the test for evaluating NWA projects can lead to this outcome.

The DCT provides an objective way to evaluate the cost of pursuing a portfolio of DER relative to deferring and/or avoiding traditional projects on the basis of the costs and benefits the distribution utility will directly realize. This implicitly addresses the customer concerns articulated by MI and the City of New York[20] because the DCT will select alternative solutions only to the extent that they reduce costs while maintaining performance relative to the traditional utility solution. As such, the DCT may obviate the need to conduct the RIM test, although the Joint Utilities have no objection to retaining the RIM test as well.

Various parties criticized the RIM test. The Northeast Energy Efficiency Partnerships consider the RIM methodologically flawed because it includes the recovery of lost revenues and focuses on rate impacts rather than bill impacts and the Environmental Defense Fund finds the RIM not meaningful because it says almost nothing about the magnitude of the rate impact.[21] The Joint Utilities submit that the Commission's fundamental public service responsibilities require it to retain an explicit valuation of customer costs through either the RIM test or an alternative approach.

---

[19] Exelon Companies Comments, pp. 3, 6-7; MI Comments, pp. 3-7, and Comments of AARP and PULP (August 21, 2015) ("AARP/PULP Comments"), pp. 1-4.

[20] MI Comments, pp. 3 & 6; City of New York Comments, p. 15.

[21] Comments of Northeast Energy Efficiency Partnerships on Staff White Paper on Benefit-Cost Analysis (August 21, 2015), p. 3; Comments of Environmental Defense Fund Regarding the Staff White Paper on Benefit-Cost Analysis Framework (August 21, 2015) ("EDF Comments"), pp. 4-5.

B. SCT

Several parties advocated for the application of the SCT as the sole test or as the primary test for evaluating DER.[22] The Joint Utilities assert that implementing the BCA solely (or even primarily) based on SCT is contrary to at least two of the Commission's REV objectives because the SCT would create a bias to reject utility projects that were more cost-effective than a DER portfolio. Such a result violates the REV objective of ***market animation and leverage of ratepayer contributions*** and, because of the inherent bias against traditional utility projects, would tend to degrade the REV objective of ***system reliability and resilience.***[23]

If the Commission does choose to use the SCT as the primary determinant for assessing the relative economics of both wires projects and NWA projects, it is imperative that the Commission also require a thorough analysis of rate and bill impacts over the duration of the BCA. Failure to do so could result in a portfolio of projects that could increase rates and bills for customers.

The flaws in the SCT are further compounded by the suggestions of various parties to quantify items that are inherently difficult to quantify and/or highly contentious. Several commenters propose to start with "placeholders" that would further bias the BCA results until a more objective value can be determined.[24] This approach would effectively force customers to pay for resources on the basis of subjective valuations of contentious items.

---

[22] *See*, *e.g*., AEEI Comments, pp. 2-3 & 12; Initial Comments of Citizens for Local Power on N.Y. Department of Public Service Staff White Paper on Benefit Cost Analysis, p. 2; and EDF Comments, p. 5.

[23] REV Proceeding, *supra*, note 5.

[24] Pace Energy and Climate Center Response to the New York State Department of Public Service Staff White Paper on Benefit Cost Analysis in the Reforming the Energy Vision Proceeding (August 21, 2015), p. 14. *See also*, Citizens' Environmental Coalition Comments on Staff White Paper on Benefit Cost Analysis in the Reforming the Energy Vision Proceeding (August 21, 2015) ("CEC Comments"), pp. 7-8. *See generally*, National Resources Defense Council Comments to New York State Department of Public Service Benefit Cost Analysis White Paper (August 21, 2015) ("NRDC Comments"), pp. 20-21.

Others parties propose to effectively ignore established market valuations and substitute artificial values. For example, several parties propose to superimpose an artificially high value for CO_2 in place of the market-based costs from the RGGI cap-and-trade market in which New York State participates. At the high end of these proposals is the argument put forth by Peak Power LLC that over $200/ton may be the true cost of carbon.[25] Such a CO_2 valuation would have the effect of superimposing a price increase of roughly $100/MWH on any traditional electricity use. This impact equates to at least a 50 percent rate increase for a number of the Joint Utilities. Similarly, the potential for upward pressure on rates would likely be exacerbated if the Commission: (1) selects Approach Number 2 to value avoided GHG costs (Section IV.B); and/or (2) includes a variety of non-energy benefits in the SCT. Upward pressure on rates would occur in this situation because the SCT would select DER portfolios requiring customer payments that are not only in excess of the utility's avoided cost under the DCT but also in excess of the direct bulk system avoided cost benefits that customers receive from the deployment of DER.

If the Commission desires to employ the SCT, it should establish a process to first assess whether the presumed benefits and costs can be objectively quantified, as has been proposed by the City of New York.[26] Furthermore, the quantifiable benefits and costs must be material enough to justify the time and effort for their quantification and application within the BCA Framework. This step is essential to prevent the BCA process from becoming a theoretical exercise, at customers' expense, of trying to quantify information which may not "move the needle" in the anticipated valuation of projects.

---

[25] Peak Power Comments, p. 8.
[26] City of New York Comments, pp. 2-3.

Moreover, the selection of the BCA components and the values placed on them may bias the NWA selection process in favor of particular DER outcomes. If the BCA Framework is used to set prices for DER it will have a direct impact on customer bills and rates, as well as the level of environmental benefits monetized and transferred from society as a whole to individual DER providers. The Joint Utilities urge that these potential effects be taken into consideration if and when such a process is designed and implemented.

C. Emissions and Other Environmental Externalities

The optimal market-based GHG emission reduction policy for the power sector would apply a single carbon price for all relevant economic actors and decisions that would equalize the marginal abatement costs across the sector—constituting a "level playing field" among all options for reducing power sector GHG emissions. The RGGI program sets the binding cap for aggregate emissions that creates a market-based price for CO_2 which, in turn, is captured in the locational-based marginal price ("LBMP") of electricity. If the State desires to achieve greater GHG emission reductions from the power sector than what is required under the present RGGI program, the most direct and efficient approach is to work with the other RGGI member states to continue to ratchet down the RGGI emissions cap. The reasonableness of such an approach is apparent from the fact that at least six of the nine RGGI states (accounting for roughly 70 percent of power sector emissions covered by the program) have state GHG emission reduction goals comparable to New York State's goal of 80 percent by 2050.

It is important to recognize that the positions taken by various parties in this proceeding could result in the situation where CO_2 emissions are valued in three different forums: (1)

RGGI, (2) Large-Scale Renewable solicitations (depending on Commission final decision),[27] and (3) values determined in REV from the BCA Framework. Three separate and distinct price signals for CO_2 emissions have the potential to create market confusion and lead to investment decisions that may not be optimal. In order to cost-effectively advance the State's energy policy goals and promote an economically efficient electricity system for New York State, the BCA Framework must treat environmental externalities appropriately. Existing environmental policies implicitly or explicitly establish market values for avoided air emissions from fossil fuel-fired electricity generation, and those market values (as embedded in New York Independent System Operator ("NYSIO") wholesale prices) should be the sole basis for capturing environmental benefits in any BCA test. This is Approach 1 of the BCA White Paper, and the Joint Utilities endorse this approach. Moreover, the Joint Utilities believe that the BCA Framework should reflect the primary environmental issues related to the electricity sector and New York State energy policy—namely reduction of GHG and other harmful air emissions.

Use of non-market-based values for air emission reductions that already have market values or expansion of the scope of analysis to include far-reaching purported environmental benefits have four primary drawbacks that the Commission should address:

1. Customers may pay for environmental benefits that, on net, society will not actually realize because the RGGI program sets a binding emissions cap and the price of tradable emissions allowances is embedded in NYISO wholesale prices. As a result, the aggregate CO_2 emissions from electric generators in the nine RGGI states will be the same regardless of the avoided emissions values assigned to DER. The same

[27] Case 15-E-0302 – In the Matter of the Implementation of a Large-Scale Renewable Program, *Notice Instituting Proceeding, Soliciting Comments and Providing for Technical Conference* (issued June 1, 2015).

basic features and implications also apply to other existing cap-and-trade programs for criteria air pollutants.

2. If used as an environmental policy tool, the BCA Framework will create an "un-level playing field" in favor of energy resources that will only achieve State energy and environmental policy goals at a higher cost to customers. More cost-effective policy mechanisms that can send consistent price signals across the power sector to spur clean energy investments and emission reductions already exist, and New York State should use these as the basis for achieving more aggressive policy goals.
3. An expansive view of externalities and their valuation will render the BCA Framework analytically intractable in pursuit of what, in many cases, are likely to be *de minimis* environmental benefits and/or other benefits that may be nearly impossible to measure or verify.
4. Relying on non-market-based environmental externality values in a BCA Framework creates the need for an incremental funding source to compensate DER projects that are deemed cost-effective.

These matters are addressed in more detail below.

The primary environmental externalities associated with the electricity system are air emissions from fossil fuel-fired electricity generation. Critically, CO_2 and criteria air pollutants are already subject to market-based, cap-and-trade policies under RGGI and U.S. EPA programs.[28] These market-based programs have two essential features. First, they set aggregate caps on the total level of emissions (*e.g.*, tons of CO_2 per year). For example, RGGI establishes

[28] The U.S. EPA's Cross-State Air Pollution Rule ("CSAPR") and the Acid Rain Program ("ARP") establish emission trading programs for SO_2 and NO_X and regulate New York power plant emissions for both fine particulates and ozone. *See* http://www.epa.gov/airmarkets/index.html.

a cap on total CO_2 emissions from electricity generators in nine states, including New York State. Second, the tradable emission allowances used under cap-and-trade programs create market prices for pollution that are embedded in NYISO wholesale prices. Taking CO_2 as the example, the implication of adopting the BCA White Paper Approach 2 to environmental externality valuation will direct investments toward more costly GHG abatement options without actually providing any environmental benefits beyond what RGGI would deliver.

This argument is illustrated with a simplified example focused on CO_2. The current RGGI CO_2 allowance price is roughly \$6.50 per metric ton CO_2.[29] In contrast, the BCA White Paper cites a "central value" for the federal government's societal cost of carbon of \$46 per ton when discounted at a 3 percent rate.[30] Assume that the BCA Framework adopts the \$46 per ton of avoided CO_2 emissions for DER while all other energy resource decisions face a RGGI-based carbon price of \$6.50 per ton.[31] This has several important implications regarding total CO_2 emissions and the cost of achieving reductions. Under any scenario the RGGI program sets the binding cap for aggregate emissions. In addition, the selection of DER based on an above-market valuation of CO_2 will increase the overall cost to New York electric customers without providing any incremental environmental benefits to New York (or the rest of the world) in terms of mitigating global climate change.

The optimal market-based GHG emission reduction policy for the power sector would apply a single carbon price for all relevant economic actors and decisions that would equalize the marginal abatement costs across the sector and thereby constitute a "level playing field" among all options for reducing power sector GHG emissions. Moreover, DER deployed as a result of a

---

[29] SNL Energy, "RGGI Secondary Market Prices Back Off After Recent Gains," August 27, 2015.
[30] BCA White Paper, at Appendix C, p. C-2.
[31] The \$46 per ton cost of CO_2 equates to roughly a 15 percent rate increase for many of the utilities.

CO_2 valuation that differs from the RGGI market price could undermine the purpose of the RGGI program by sending an economically, inefficient price signal to electricity generators and consumers that is skewed by the artificially high carbon price applied to DER. Similar arguments apply to the other air pollutants subject to market-based cap-and-trade programs.

Statements that the BCA Framework should be sufficient to achieve New York State GHG emission reduction goals[32] and arguments for using non-market-based values for environmental externalities constitute a fundamental misapplication of the BCA Framework. The Joint Utilities do not suggest that the RGGI allowance price accurately reflects the social cost of carbon or that the RGGI program is presently a sufficiently stringent emissions reduction policy to achieve the State's climate change goals. Nonetheless, the BCA Framework should not in and of itself be an environmental policy tool to deliver GHG emission reductions and other environmental benefits.

The BCA Framework should accurately quantify the value that DER provides in terms of compliance with actual environmental policies, such as RGGI. As the example above clearly demonstrates, if the State desires to achieve greater GHG emission reductions from the power sector than what is required under the present RGGI program, the most direct and efficient approach is to work with the other RGGI member states to continue to ratchet down the RGGI emissions cap. As noted above, the reasonableness of such an approach is apparent from the fact that at least six of the nine RGGI states (accounting for roughly 70 percent of power sector emissions covered by the program) have state GHG emission reduction goals comparable to New

---

[32] Notably, NYSDEC and Acadia Center express the concern that the BCAH will not allow the State Energy Plan to meet its goal of GHG emissions reductions by 2050. *See* NYSDEC Comments, pp. 3-5; *see also* Acadia Center Comments, pp. 3-4.

York State's goal of 80 percent by 2050. As such, the RGGI program is a natural vehicle for achieving New York State's power sector CO_2 emission reduction goals.[33]

Many parties praise RGGI for its success in cost-effectively reducing power sector GHG emissions. Ironically many of the same parties propose to create an "un-level playing field" among DER and other energy resources by establishing widely divergent carbon prices. NRDC, for example, recently explained that RGGI "has helped cut greenhouse gas pollution from power plants by more than 40 percent since it was first implemented in 2005" while "at the same time, the region's economy has grown faster than the rest of the country's, adding thousands of new jobs in fields like energy efficiency and renewable energy, and saving customers hundreds of millions on their energy bills already, with billions more to come."[34] The reality is that New York State is part of a successful market based GHG cap-and-trade program (the first of its kind in the United States) that has served as a model for proposed federal legislation and compliance with the U.S. EPA's Clean Power Program. RGGI is the best vehicle available to address GHG emissions from the power sector, and the RGGI carbon price signal provides an incentive for all power-sector-related carbon abatement investments both upstream in the wholesale market as well as through the deployment of DER.

Some parties suggest that the BCA Framework should take an overly expansive view of externalities related to electricity generation, transmission, and distribution of air pollutants from electricity generation that are presently covered by cap-and-trade programs.[35] This approach is

---

[33] *See* http://www.c2es.org/us-states-regions/policy-maps/emissions-targets and the World Resources Institute CAIT Climate Data Explorer, available at http://goo.gl/Lt7z7Q.

[34] *See* http://switchboard.nrdc.org/blogs/jmorris/harnessing_the_energy_to_lead_.html.

[35] *E.g.*, the joint comments of the Alliance for a Green Economy, *et al.* on the Department of Public Service Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (August 21, 2015) ("AGE Comments"), p. 2, would add and quantify avoidance of pollutants such as methane; NYSDEC Comments, pp. 4-6, would add methane, nitrous oxide, and sulfur hexafluoride, as well as land and water impacts; TASC Comments, p.

far beyond the main focus of the BCA White Paper and suffers from multiple drawbacks. First, it ignores the costs of complying with many non-market-based environmental regulations (*e.g.*, air, land, and water regulations) that are already implicitly embedded in wholesale electricity costs such that the avoided wholesale electricity costs that accrue to DER providers already reflect value from avoided air, land, and water impacts. Second, expanding the environmental scope of the BCAH would require substantial analytical complexity and uncertainty to capture benefits that are likely to be relatively small and very difficult to measure and verify (*e.g.*, the suggestion from Sustainable Otsego that the BCAH consider the impacts of DER on formaldehyde in the environment).[36]

The "level playing field" concern applies to the expansive use of environmental externalities in the BCA Framework as well. Effectively subsidizing DER alone for broad, potential environmental benefits will not deliver those benefits at the lowest cost to utility customers because potentially less expensive options for delivering those benefits will fall outside the scope of the BCA Framework and REV.

Lastly, relying on non-market-based environmental externality valuations, like a social cost of carbon, to determine the cost-effectiveness of DER under the BCA Framework would require an incremental source of funding to procure or compensate DER that are deemed cost-effective and will increase electric customer bills. Valuing environmental externalities using an approach other than Approach 1 in the BCA White Paper will tend to find DER options cost-

16, would include methane losses from the natural gas supply chain for power plants; Comments of the Association for Energy Affordability, Inc. on the Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (August 21, 2015) ("AEA Comments"), p. 10, adds impacts on land and water use and quality; CEC Comments, p. 5, adds the avoidance of other criteria pollutants – volatile organic compounds ("VOCs"), ozone, and particulate matter (PM-2,5 and 10); and Sustainable Otsego Comments on the Benefit-Cost Analysis (BCA) White Paper (August 21, 2015) ("Sustainable Otsego Comments"), pp. 1-2, would also add methane, particulate matter, VOCs, ground-level ozone, formaldehyde, and natural gas hydraulic fracking effects.

[36] Sustainable Otsego Comments, p. 2.

effective when those options do not provide sufficient benefits in the form of net avoided costs that actually flow through utility customer bills to offset the payments required to deploy those DER options. Putting aside the question as to whether this approach would actually deliver any incremental environmental benefits at all, this approach would, in essence, constitute levying a "tax" on electric customers for environmental benefits over and above those already yielded by existing state and federal environmental policies.

D. Valuation of Non-Traditional Costs and Benefits

As noted above, the Joint Utilities maintain that the DCT is the most appropriate BCA test to use within REV. The use of the DCT will moderate increases to customer bills by avoiding the monetization of benefits not related to energy or marginal distribution system costs. The Joint Utilities are concerned with the potential to increase customer bills through the inclusion of non-traditional benefits and agree with the Exelon Companies Comments, which cautions against the "temptation to use 'creative' benefits to support otherwise uneconomic DER projects."[37] One such benefit urged by many parties for the BCA Framework is wholesale market price impacts.[38] The Joint Utilities disagree with this approach and agree with the City of New York and the Exelon Companies which argue that the inclusion of market price impacts "in isolation, is likely to produce inaccurate and unreliable results"[39] and "is highly speculative."[40] The discussion of the market price impacts in the BCA White Paper appears generally consistent

37 Exelon Companies Comments, n. 4, p. 3.

38 AEEI Comments, pp. 14-16; Acadia Center Comments, p. 4; Comments from the Advanced Energy Management Alliance on Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision (August 21, 2015) ("AEMA Comments"), p. 7; TASC Comments, pp. 12 -13; NY-BEST Comments, p. 10; Vote Solar Comments on BCA White Paper on Benefit-Cost Analysis (August 21, 2015), pp. 4-5.

39 City of New York Comments, p. 12.

40 Exelon Companies Comments, p. 16.

with this view.[41] Moreover, the effects of wholesale price suppression could produce unintended consequences including offsetting capacity market impacts.

A few parties also argue for the inclusion of non-traditional benefits such as: (1) health benefits;[42] (2) economic development and job creation;[43] and (3) avoided noise and odor pollution.[44] The Joint Utilities agree that these are worthy goals. However, the subjective quantification of these benefits will result in a system where DER investments are favored above traditional utility investments. While this will result in higher DER adoption, it might also result in negative outcomes such as decreasing electric grid reliability and increasing costs. Additionally, any economic impacts such as job creation that may be associated with DER adoption should be considered holistically and netted with any potential negative economic impacts such as the potential job losses and lower property tax collections that may be associated with reduced reliance on traditional large-scale generation and the negative knock-on effect on overall employment from increases to customer bills required to fund DER.

Another challenge associated with the inclusion of non-traditional benefits, within the BCA Framework, is that the very nature of these benefits makes them difficult and costly to quantify or measure and validate.

The Joint Utilities reiterate that the DCT is the appropriate test for the BCA Framework and that non-traditional benefits should not be included. However, if the Commission directs the inclusion of any non-traditional benefits within the BCA, the Commission should also require

---

41 BCA White Paper, pp. 19-20.
42 Policy Integrity Comments, p. 11; AGE Comments, pp. 2-3.
43 *Id*.
44 AEEI Comments, p. 13.

that the costs associated with developing and maintaining the required measurement and verification be included within the BCA.

E. Discount Rate

1. The weighted average cost of capital ("WACC") is fully appropriate for the DCT.

There are significant differences among the parties concerning the appropriate discount rate to employ in the BCA.[45] The purpose of the BCA is, as noted earlier, to compare wires and NWA projects. The BCA test that the Joint Utilities support is the DCT because it considers utility transmission and distribution benefits and costs that will be borne directly by customers in transmission and distribution charges under both wires and NWA projects. The benefits realized and costs incurred under this approach are direct utility costs related to the deployment of capital and other direct expenses. As such, the WACC is the only discount rate reflective of the actual cost to each utility and its customers of financing these activities. As such the WACC is fully appropriate as the DCT discount rate.

The Joint Utilities also support the use of the WACC in other BCA test(s) as well. As stated in the BCA White Paper:

> While others have argued that different discount rates should be applied to different metrics (e.g. social discount rates for the societal cost metric, WACC for the utility cost metric), staff proposes that a single discount rate be used for all metrics. This is based on the rationale that, whatever metric is used, a decision is being made on alternative utility expenditure plans, costs that are ultimately collected from ratepayers. Thus, staff's proposal is that the overall discount rate should reflect the opportunity cost of capital for such expenditures.[46]

---

[45] *See*, *e.g.*, Policy Integrity Comments, pp. 7-9, and EDF Comments, pp. 4-5, that argue for the societal discount rate; City of New York Comments, p. 3, that argue for the a cost of capital for ratepayers; and Peak Power Comments, p. 4, that supports the WACC as the discount rate for the majority of BCA tests.

[46] BCA White Paper, p. 10.

The use of a lower societal discount rate increases the weight given to benefits and costs over a longer time horizon. This creates two significant problems in the application of the DCT. First, the use of a societal rate in the DCT could pass projects that fail to produce benefits under the DCT at the utilities' opportunity cost of capital (*i.e.*, WACC). These incremental projects will increase utility costs and ultimately rates and bills to customers. The second problem is that the lower societal discount rate gives greater value to benefits that are farther in the future and by definition are more speculative. Both of these considerations support the use of the WACC as the appropriate discount rate for the DCT.

2. Arguments supporting the use of a societal discount rate provide no specific evidence why a low societal rate should be employed to discount future costs and benefits under any BCA test.

The positions taken by the parties supporting the societal discount rate vary. In general it appears that most proponents of this approach recommend a discount rate in the 0 percent to 3 percent range. Some arguments support the use of this lower societal discount rate and are discussed below.

AEEI's Comments supporting the position that investments in DER are less risky than investments in traditional utility solutions[47] is speculative at best. The characteristics and risks of future DER investments are largely unknown as the market and the rules governing it have yet to develop. Thus, there is a high level of uncertainty regarding the performance of investments (the future streams of benefits and costs) in new technologies operating in an as yet undefined and undeveloped market for the specific purpose of meeting the needs of the electric grid which are financed by the utility and its customers. This high level of uncertainty is indicative of greater risk and the use of a greater discount rate than the WACC. Moreover, DER refers to a

[47] AEEI Comments, pp. 10-12.

wide range of technologies, services, and providers; their associated business risks and as a result their cost of capital could vary substantially.

The parties in support of a lower discount rate[48] refer generally to the mathematical fact that the lower societal discount rate produces higher values of long-run avoided costs and benefits for DER than would be realized under a WACC-based approach. However, the parties provide no theoretical underpinning explaining why it is proper to employ the lower rate. Rather, the lower discount rate is favored simply because it produces results that favor DER over traditional solutions because it gives greater weight to longer term impacts. Ultimately, these positions reflect a results-oriented approach that tilts the playing field in favor of DER and provide no reasonable basis for adopting the societal discount rate.

Of the parties supporting the use of a societal discount rate, the most complete explanation comes from NRDC which states:

> NRDC recommends that the utility WACC not be used as the basis for the BCA discount rate. The utility WACC represents the time preference of utility shareholders and bondholders; not the time preference that should be applied to utility resource planning. Utility shareholders and bondholders have their own perspectives regarding opportunity costs, risks, and personal investment goals. In general, they have their own perspectives on the value of short-term versus long-term benefits.
>
> *We recommend that instead the BCA discount rate be based on the time preference that reflects the interests of all utility customers as a whole and is consistent with New York's key regulatory goals. Such a time preference would give higher priority to long-term benefits, and would be lower than the utility WACC. When making electricity resource planning decisions, it is important to recognize that resource decisions made today have implications for customers many years into the future, and that utilities and regulators have a responsibility to ensure that resources chosen today will serve customers' interests well into the future*…[t]he societal discount rate is best able to reflect the value of short- versus long-term costs and benefits to all utility customers (emphasis added).[49]

[48] TASC Comments, pp. 6-9; AEA Comments, pp. 7-8; and CEC Comments, pp. 8-9.
[49] NRDC Comments, p. 17.

The Joint Utilities agree that the discount rate should reflect the "interests of all customers" as well as "key regulatory goals."[50] Further, the Joint Utilities agree that the Commission has the responsibility to assure that "resources chosen today…serve customer's interests well into the future."[51] While the Joint Utilities agree with these key concepts, there is no basis for concluding that the lower societal discount rate is consistent with any of them. The clear implication of NRDC's explanation is that all customers assess investment and consumption decisions based on the expectation that an alternative use of their funds would produce a return to them of between 0 percent and 3 percent. Put another way, NRDC's explanation assumes that the cost of capital for all of the Joint Utilities' customers is between 0 percent and 3 percent. Such a perspective is flawed and should be given no weight.

First, NRDC's view assumes that all commercial and industrial ("C&I") customers have a significantly lower cost of capital than the utilities' WACC. Considering the size and financial integrity of the utilities, as measured by their investment grade bond ratings, there is no basis to conclude that all C&I customers have a cost of capital that is hundreds of basis points less than the WACC. If anything, the fact that utilities' betas, as reported by Value Line, are less than the market average of 1.0 indicates that utilities' risk and resultant cost of capital is somewhat less than what is typical for large corporations.

Second, NRDC's view does not consider the situation facing residential customers. For example, REV has drawn, and seeks to consider,[52] interest in matters impacting low and

---

[50] *Id*.
[51] *Id*.
[52] *See* Case 15-E-0822 –Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, *Notice of Collaborative Meeting Concerning Community Distributed Generation for Low-Income Customers* (issued August 19, 2015),where "Staff is convening a collaborative meeting to investigate and evaluate low-income customer participation in community distributed

moderate income customers who typically have fewer resources. The use of a societal discount rate ignores the fact that many low-to-moderate income customers face more basic investment decisions related to immediate needs such as food, clothing, and housing. The use of a societal discount rate implies that low-to-moderate income customers value investments in these fundamental living requirements as the equivalent of a return of between 0 percent and 3 percent on their limited funds. Such a position is flawed because it simply ignores the consequences of not having food, clothing, or housing.

Third, NRDC's view does not attempt to consider the circumstances of residential customers other than low-to-moderate income. While it is possible that some residential customers with extremely conservative investment strategies could have a marginal cost of capital in the 0 percent to 3 percent range, it is likely that many other residential customers seek higher returns for the use of their moneys. Finally, NRDC's view does not consider the amount of consumer debt that currently exists and the implication that the marginal cost of capital for some customers is likely to be the interest on consumer debt.[53]

Fourth, NRDC's argument that the societal discount rate should be used for electric resource planning contradicts clear industry best practice demonstrating that the utility WACC is the appropriate discount rate to use for comparable electric resource planning. National Grid's affiliate company addressed this point in its recent Electric Grid Modernization proceeding in Massachusetts, where the Massachusetts Department of Public Utilities directed the Massachusetts utilities to use the utility WACC as the discount rate for grid modernization

---

generation, including removing potential barriers to their participation and devising possible demonstration projects to encourage broad participation."

[53] *See* http://www.federalreserve.gov/releases/g19/current/

electric resource planning benefit-costs analysis.[54] In that proceeding, National Grid's affiliate utility company explained that a review of similar electric resource planning benefit-cost analyses across eleven utilities spanning nine jurisdictions found only one example where a utility used a societal discount rate and, in that case, the regulator rejected the discount rate as inappropriately low.[55]

The Commission is responsible for assuring that ratepayer moneys are prudently spent. NRDC and others would have the Commission discount future benefits and costs at a societal rate that is lower than the cost of capital for the Joint Utilities' commercial and industrial customers, low-to-moderate income customers, and many residential customers. The end result is the inefficient allocation of customers' capital to investments that will produce unnecessary upward pressure on utility rates and bills. While the WACC may not reflect the marginal cost of capital with complete precision for all customers, it does, as noted in the BCA White Paper,[56] reflect the utility opportunity cost of capital for future investments decisions and has been employed as the standard for the electric utility industry for many years.[57]

F. Sensitivity Analyses

The positions taken by several parties imply the need for a significant amount of sensitivity analyses to test a variety of key assumptions including: (1) power prices,[58] (2) varying levels of DER,[59] (3) customer penetration,[60] (4) locational and service territory load growth,[61] (5)

---

[54] Massachusetts Department of Public Utilities, D.P.U. 12-76-C, p. 18.

[55] Comments of Massachusetts Electric Company d/b/a National Grid in Massachusetts Department of Public Utilities Docket No. D.P.U. 12-76, August 22, 2014, pp. 16-17.

[56] BCA White Paper, p. 60.

[57] It is also important to recognize that utilities will be responsible for addressing the risk of shortfalls in DER performance resulting in the need to make further capital investments that will financed at the utility cost of capital.

[58] TASC Comments, p. 11.

[59] Policy Integrity Comments, p. 7.

[60] NRDC Comments, p. 3.

pricing options,[62] (6) regulatory/legal/policy changes,[63] and (7) customer rate and bill impacts.[64] The BCA White Paper states that sensitivity analyses should be performed on "key assumptions" and that the BCAH should contain a "description of the sensitivity analysis…that will be applied to the BCA."[65] The BCA White Paper also suggests that the sensitivity analysis might include a low, medium, and high scenario for costs and benefits.[66]

The Joint Utilities agree that the application of BCA test(s) are likely to require a sensitivity analyses and the initial BCAH will consider the statements in the BCA White Paper as well as the initial comments and reply comments of the parties on this matter. Consistent with the new general principle recommended in the Joint Utilities Initial Comments that "the process for applying and updating the Benefit Cost Analysis Handbooks ("BCAH") should not be costly or administratively burdensome for any party," the use of sensitivity analyses should be limited to those that are practicable and likely to prove informative to decision-making.

V. BCAH DEVELOPMENT MATTERS

Several parties suggest that that the BCAH provide: (1) a transparent look at the formulas and modeling approaches that will be employed to assess alternatives; (2) examples showing how the tests will be applied; and (3) tool sets and protocols for DER providers to assess their proposals.[67] The Joint Utilities are concerned that many parties see the BCAH as a document that not only addresses every possible DER application but also provides the quantitative tools

---

[61] NY-BEST Comments, p. 4.
[62] *Id*., p. 6.
[63] *Id*.
[64] AARP/PULP Comments (August 21, 2015), p. 7.
[65] BCA White Paper, p. 9.
[66] *Id*.
[67] AEMA Comments, p. 4; TASC Comments, pp. 4-5; Northeast Clean Heat and Power Initiative Comments on Staff White Paper on the Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (August 21, 2015), p. 2.

needed to assess each application. Such an approach is not workable given the diversity of potential DER applications that may develop in the future. Rather the Joint Utilities anticipate developing BCAHs that describe the economic tests that will be employed and list key assumptions and inputs that would be used in any BCA analysis. While differences in service territory characteristics may require differences in the content of each BCAH, all assumptions, data, and relevant information will be presented in a useable, transparent, and consistent format for all parties to use for their own purposes. The Joint Utilities also suggest that the BCAHs be updated annually to reflect changes in inputs, the availability of new data, and changes in other input variables as experience is gained and new applications for the BCA Framework emerge. The Joint Utilities continue to support the filing of the initial BCAH concurrent with the filing of the utilities' DSIPs, currently set as June 30, 2016.

Some parties also discussed the process employed to develop the BCAH and recommended a stakeholder engagement collaborative.[68] One party suggests that the handbook should be prepared by a state agency.[69] The Joint Utilities oppose both approaches. While the Joint Utilities will take the comments of all parties into consideration, the development of a handbook for use by utilities in a stakeholder collaborative or by a state agency o would not be efficient because it could not possibly reflect unique service territory considerations affecting each utility. The Joint Utilities anticipate starting work themselves in a timely manner on the BCAH with DCT as the economic test for evaluating wires versus NWA projects. The initial BCAH will reflect both certain quantifiable elements of benefits and costs and identify a path

[68] The Nature Conservancy Comments on the Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (August 21, 2015), p. 10; and NY-BEST Comments, p. 5.
[69] CEC Comments, p. 2.

forward to develop the more difficult-to-quantify benefits and costs for subsequent editions of the BCAH, such as costs and benefits with more locational and temporal granularity.

VI. CONCLUSION

The Joint Utilities respectfully request that the Commission consider the position of the Joint Utilities in their Initial and Reply Comments and act on the BCA White Paper taking into account the concerns set forth above.

Date: September 10, 2015

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

By: /s/ *Janet M. Audunson*

Janet M. Audunson
Senior Counsel II
National Grid
300 Erie Boulevard West
Syracuse, New York 13202
Tel: 315-428-3411
Email: Janet.Audunson@nationalgrid.com

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. and ORANGE AND ROCKLAND UTILITIES, INC.

By: /s/ *Susan Vercheak*

Susan Vercheak*
Assistant General Counsel
Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, New York 10003
Tel.: 212-460-4333
Email: vercheaks@coned.com
* Admitted only in New Jersey

CENTRAL HUDSON GAS AND ELECTRIC CORPORATION

By: /s/ *Joseph Hally*

Joseph Hally
Manager, Energy Transformation & Solutions
Central Hudson Gas & Electric Corporation
284 South Avenue
Poughkeepsie, New York 12601
Tel: 845-486-5373
Email: jhally@cenhud.com

NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION

By: /s/ *Joseph J. Syta*

Joseph J. Syta
Vice President, Controller & Treasurer
NYSEG and RG&E
89 East Avenue
Rochester, NY 14649
585-724-8003
Email: joseph_syta@rge.com

nationalgrid

Melissa G. Liazos
Senior Counsel

August 22, 2014

VIA HAND DELIVERY AND E-FILING

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid
D.P.U. 12-76 – Grid Modernization

Dear Secretary Marini:

On behalf of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid (the "Company"), enclosed for filing in D.P.U. 12-76 please the Company's Comments on the Department's Business Case Filing Requirements and Summary Template, and Responses to Briefing Questions, as well as the Company's proposed redlines to the Department's Business Case Filing Requirements document. The Company reserves the right to reply to any comments that others may file.

Thank you for your time and attention to this matter.

Very truly yours,

Melissa G. Liazos

Melissa G. Liazos

Enclosures

cc: Alison Lackey, Hearing Officer
Sandra Merrick, Office of the Attorney General
Jesse Reyes, Office of the Attorney General
Jamie Tosches, Office of the Attorney General
Service List (electronic only)

40 Sylvan Road, Waltham, MA 02451-1600
T: 781-907-2108 ■ F: 781-296-8091 ■ melissa.liazos@nationalgrid.com ■ www.nationalgrid.com

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid	)	D.P.U. 12-76

NATIONAL GRID'S COMMENTS ON THE DEPARTMENT'S BUSINESS CASE FILING REQUIREMENTS AND SUMMARY TEMPLATE, AND RESPONSES TO BRIEFING QUESTIONS

By its attorney:

Melissa G. Liazos
Senior Counsel
National Grid
40 Sylvan Road
Waltham, MA 02451
Telephone: 781-907-2108
Email: melissa.liazos@nationalgrid.com

Submitted: August 22, 2014

TABLE OF CONTENTS

NATIONAL GRID'S COMMENTS ON THE DEPARTMENT'S BUSINESS CASE FILING REQUIREMENTS AND SUMMARY TEMPLATE, AND RESPONSES TO BRIEFING QUESTIONS

I. Introduction and Executive Summary

Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid" or "Company") support the Department's proposal that utilities should conduct a business case analysis of the investments proposed in their Short Term Investment Plans ("STIPs") as part of the their Grid Modernization Plans ("GMPs"). National Grid supports the high-level requirements contained in the Department's proposed Business Case Filing Requirements ("Requirements") and Business Case Summary Template ("Template". A number of items in the Requirements should be clarified, however, in order to better reflect the utilities' planning processes for selecting capital investments and to recognize that estimates of costs and benefits cannot be defined with complete precision when developing a STIP. Costs and benefits necessarily will be subject to change from original estimates over the five year horizon for the STIPs, and the Department's approval of a company's proposed STIP should recognize this and should allow for a range of costs and benefits to be included.

Regarding the recovery of stranded costs, the proposed Requirements suggest that a distribution company "may" be allowed to recognize retirements of stranded assets as extraordinary losses and be allowed to recover the undepreciated balance through amortization.[1] Distribution companies should be allowed to recover the remaining net book value of assets that have been used and useful in providing service to customers but that must be retired prematurely as a result of the Department's requirement to make measurable progress toward its four grid modernization objectives, and to achieve advanced metering functionality within a certain

[1] Requirements at p. 7 n. 9.

timeframe. National Grid has used and useful assets that would remain in service but for the Department's directives on grid modernization (such as AMR meters). Not allowing recovery of and on these assets is a disincentive to pursuing the Department's grid modernization goals, and could result in delays in the implementation of GMPs, or in plans that first replace equipment that is fully depreciated and delay replacement of equipment that has remaining net book value. Approval of a company's STIP and GMP therefore should include approval of a company's proposal for recovery of the undepreciated costs of these assets and carrying charges. Other utility regulators have adopted provisions specifically in the case of advanced meter deployment to allow for a return of and on investments in stranded meters.

Regarding the proposed Template, National Grid appreciates the flexibility in the Department's proposal to allow utilities to include additional types of costs and benefits in their Template. National Grid also urges, however, that the Department not be overly prescriptive by requiring the mandatory application of a pre-defined template, prior to the utilities or the Department having begun to consider in detail the specifics of actual STIPs. The utilities should have the ability to refine the template as they develop their actual STIP proposals and associated business case analyses, in order to better reflect learnings as they go through this process.

In addition, the Template seems to assume that there will be a simple one-to-one or one-to-many correspondence between Grid Mod Objectives, Actions/Impacts, Functionalities, Technologies/Devices/Systems, and Benefits. This is likely to not be the case for a number of investments, however. Further, in some cases a particular benefit is likely to be realized as a result of several grid modernization investments and new operations and maintenance ("O&M") activities working together, without distribution companies being able to apportion the benefit across different Technologies/Devices/Systems.[2] In order to address this issue the Department should consider re-structuring the Template Benefits section so that the logic of the worksheet flows in the opposite direction, i.e., the Template would first focus on a particular benefit and then define the Functionalities and Technologies/Devices/Systems that would enable that benefit. The Template should allow for a single benefit (with a single present value quantification) to be mapped to multiple Functionalities, Technologies/Devices/Systems, Grid Mod Objectives, and Actions/Impacts.

II. Comments on Business Case Filing Requirements

National Grid supports the Department's proposal that each company's STIP should include a composite business case that illustrates how the STIP investments will achieve measurable progress toward the Department's four grid modernization investments, and that each company must present an overall assessment of whether its business case justifies the proposed investments. National Grid also supports the four primary components of the business case that the Department has identified, i.e.: (1) goals, scope and scale, and drivers for investments; (2) detailed descriptions of the proposed investments, and identification and quantification of all quantifiable benefits and costs associated with the STIP; (3) identification of all difficult to quantify/unquantifiable benefits and costs; and (4) stranded cost analysis. National Grid agrees that, when filling out the Template, distribution companies should have the flexibility to add additional benefits or costs not specifically listed on the Department's Business Case Summary Template, and believes that distribution utilities should have additional flexibility to modify the

[2] This many-to-many mapping of benefits to technologies/functions is evident in Table 4-8 in the Electric Power Research Institute's *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, January 2010.

template based on their learnings during their development of their STIP proposals. National Grid offers some specific comments on each of these four components, below.

A. Goals, Scope and Scale, and Drivers

National Grid is supportive of the Department's proposal that distribution companies should include the reasoning and rationale for their proposed investments. The business case analysis will consider not only the costs and benefits of proposed investments, but also other important factors such as customer bill impacts, safety and impacts on reliability. National Grid will conduct a holistic analysis of its proposed STIP that will consider these other important factors as well.

National Grid suggests that the proposed requirement that the STIP "discuss any alternative investments considered and the rationale for choosing the proposed suite of investments" should refer to a discussion focusing on a utility's planning framework, including the types of investments considered, the process for evaluating those investments, and the criteria for choosing preferred investments. This discussion should be focused on a utility's process for developing its plans, the reasonable alternatives considered, and the screening of those alternatives in order to develop the optimal investment plan. Otherwise, if this requirement is intended to mandate, for example, that a utility discuss every single alternative individual piece of equipment considered, this would be a burdensome and time-consuming review that would not provide meaningful insight into the selection process.

B. Project Descriptions and Analysis of Quantifiable Benefits and Costs

1. Projected Costs: A Range of Projected Costs Should Be Included in the Analysis of Quantifiable Costs.

The Requirements require the Company to provide cost estimates, using vendor quotes whenever possible. National Grid supports the use of vendor quotes where possible, but the

Department should recognize that any vendor quotes used in the development of a GMP, as well as vendor cost estimates during the early stages of implementation of a GMP, are estimates that are subject to change and the companies should not be strictly limited by those preliminary cost estimates. Vendor quotes used for the Requirements will be vendors' preliminary best estimates based on high-level assumptions about anticipated project scope, timing and complexity. These quotes and early conceptual estimates will necessarily be more rudimentary and preliminary than cost estimates available after a project has been fully scoped, requirements documents have been completed, and contracts with vendors are finalized. In addition, later vendor cost estimates and bids will likely vary from preliminary vendor quotes due to such factors as inflation, bids becoming stale due to the passage of time, and competitive RFP processes and possible early strategic bidding by vendors.

Even after obtaining more robust vendor cost estimates subsequent to competitive bidding, negotiations, and contracting, once the Company actually begins to implement its GMP there will necessarily be changes to some of the specifics of the deployment and costs of particular technologies or solutions, for a myriad of reasons. These include challenges encountered in deployment in the field, changes in technology, unforeseen issues that arise with the compatibility or incompatibility of different technologies that must work together, siting and permitting challenges, etc. The time period for implementation of the five year STIP will not even begin to run until after the Department has issued its final orders on the benefit cost analysis and on time varying rates,[3] the distribution companies have filed their GMPs nine months later, and the Department has approved the GMPs, a process which is likely to take a number of years. There will necessarily be less precision in the current estimates of costs (and

[3] D.P.U. 14-04.

benefits) expected to be realized in a five-year STIP (particularly in the later years of the STIP) that covers a timeframe extending substantially more than five years from now.

In addition, costs for grid modernization/Smart Grid technologies in particular can be difficult to estimate for a number of reasons, including:

- Integration of digital technology is an important part of grid modernization, but these technologies have different failure rates and life expectancies than the majority of today's grid technologies, and the resultant failures and replacement rates must be estimated.
- Digital technology has a more rapid obsolescence rate, and changes in related technologies may make system components obsolete or inoperable with respect to the rest of the information and communications technology system well before the end of their lives, so reasonable replacement costs must be estimated.
- Improvements in modern technologies and projected cost decreases will occur at a greater rate than conventional technologies.
- There is uncertainty in performance for some Smart Grid technologies, particularly newer technologies, and if their performance is marginal or decreases over time, they may need to be replaced sooner than expected.
- As technologies mature, their marginal costs have the potential to decline.[4]

In addition, the selection of a particular vendor is based on more than just cost alone. There are other important factors that must be considered including safety, reliability, experience, capability to deliver, etc.

The Department's review and approval of projected costs should recognize these many factors. For all of these reasons the business case analysis should allow for a range of costs (as opposed to one fixed cost) to be included in the projections and in the budgets for STIPs.

[4] Electric Power Research Institute, "Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resulting Benefits of a Fully Functioning Smart Grid: Final Report, March 2011", at 3-4 to 3-5 ("EPRI Report").

2. Projected Benefits.

a. A Range of Benefits and a Focus on Aggregate Savings Should be Included in the Projected Benefits.

National Grid agrees that companies should describe the projected benefits of their STIPs. As with cost estimates, for many benefits it will be appropriate to provide a range for the value of expected benefits, and the companies should be allowed the flexibility to propose a range of values.[5] Many grid modernization investments may rely on factors outside of a distribution company's control in order to achieve expected benefits. For example, changes in customer usage may be necessary to achieve certain benefits. A company may install technologies that enable demand response and/or time varying rates, but customers may or may not choose to participate in these options, and the level of benefits that may materialize from these investments therefore is subject to variability that is outside of a distribution company's control.

In addition, the proper frame of reference for the business case analysis is the effect on customers in aggregate. As such, the analysis of "customer" costs saved as a result of grid modernization investments should be focused on cost savings in the wholesale energy markets and the capacity markets, as well as costs saved in deferred or avoided transmission and distribution ("T&D") investments or lower T&D system O&M costs, which result in lower costs to serve customers. Bill reductions for customers in the aggregate are paid for by these reductions in electric system costs, when aligned appropriately through customers' efforts and the GMP. For example, certain measures associated with grid modernization which customers adopt behind the meter may lead to those customers having lower bills, but absent a reduction in

[5] For example, the EPRI Report provides a range of projected benefits from adopting a Smart Grid. EPRI Report at 4-5, 4-10.

the utility's total cost of providing service (or to the overall costs that are passed through to customers from the wholesale market) there are no net savings for customers or lower customer bills in the aggregate.

In addition, a proposed in the Requirements, National Grid will work with the other utilities to develop the Common Assumptions and Values set forth in Table 1 of the Requirements.

b. Utilities must be allowed to recover the value of undepreciated assets and appropriate carrying charges.

Regarding the proposed Table 2: Common Analysis Methods of the Requirements, although the Department has proposed that the undepreciated value of existing assets that are replaced as a result of the STIP will not be included in the analysis of benefits and costs in a STIP, it is essential that distribution companies be allowed to recover all of the undepreciated value of these assets as well as appropriate carrying charges. The proposed Requirements suggest that a distribution company "may" be allowed to recognize retirements of these assets as extraordinary losses and be allowed to recover the undepreciated balance through amortization.[6] Distribution companies should be allowed to recover the costs for assets that they replace as part of a GMP in order to achieve one or more of the Department's objectives for grid modernization.

Approval of a company's STIP and GMP therefore should include approval of a company's proposal for recovery of the undepreciated costs of these assets and carrying charges. Distribution companies should be allowed to recover the remaining net book value of assets that have been used and useful in providing service to customers but that must be retired prematurely as a result of the Department's requirement to deploy advanced metering functionality ("AMF")

[6] Requirements at p. 7 n. 9.

and associated grid modernization investments within a certain timeframe. Failure to recover a return of and a return on the investments in these prematurely retired assets, which are still used and useful and would only be retired earlier than normal in order to meet the Department's requirements to achieve AMF and progress toward its grid modernization goals, would provide a disincentive for companies to pursue grid modernization. This could result in (1) delays in the implementation of GMPs, (2) longer timelines for the implementation of AMF and progress toward the Department's goals, and (3) plans that first replace equipment that is fully depreciated and delay replacement of equipment that has remaining net book value. Other utility regulators with similar general policies regarding the recovery of costs associated with abandoned plant or early retired assets, such as the California Public Utilities Commission, have adopted provisions specifically in the case of advanced meter deployment to allow for a return of and on investments in stranded meters.[7]

c. Discount Rate.

Table 2 states that the Discount Rate should be the "Weighted average cost of capital and/or 20-year treasury, as appropriate." The WACC is the appropriate discount rate to use for grid modernization investments, not the 20-year treasury rate. The reference to the 20-year treasury rate therefore should be deleted from the Requirements. (Please see the Company's Response to Question 1 of the Department's Briefing Questions in Section V.A of these Comments for further discussion of this issue.)

[7] California Public Utilities Commission Decision 11-05-018, at 55-57 (May 5, 2011) ("Costs can be stranded in a number of different ways, but when they become stranded due to Commission desires or actions that fact should be taken into consideration when determining appropriate ratemaking."; allowing for return on equity investment in retired meters in the case of electromechanical meters prematurely retired due to smart meter rollout).

d. Time Horizon.

Additionally, Table 2 of the Requirements defines the "BCA Time Horizon" as the "projected depreciable life of the technology/asset". National Grid recommends that the definition of the "BCA Time Horizon" be revised to state that "The cumulative benefits and costs from a prospective investment alternative should be evaluated over 15 years, with a terminal value appropriate to the technology under consideration." This was the recommendation that National Grid and the other electric utilities made to the Grid Modernization Benefit-Cost Analysis Working Group.[8] The Requirements should use this definition because the STIP will include investments in assets of different types with a range of projected depreciable lives. As such, the Department should select a single timeframe for analysis that is aligned with the anticipated economic life of advanced meters, which are the focus of the STIP, and that is sufficiently long to capture the STIP investment costs as well as a transition to a relative steady-state of benefits realization since there is likely to be a time lag between when STIP costs are incurred and the full range of projected benefits realized. The Department should balance the need for the timeframe of analysis to sufficiently capture costs and benefits with the increasing uncertainty that a business case analysis faces as the timeframe extends further into the future.

C. Analysis of Unquantifiable Benefits and Costs

National Grid supports the Department's proposal to include an evaluation in the business case of the unquantifiable or difficult to quantify benefits that are expected to result from a STIP. National Grid agrees that, when conducting their analyses, distribution companies should be

[8] D.P.U. 12-76-A, Fitchburg Gas and Electric Light Company d/b/a Unitil, National Grid, NSTAR Electric Company and Western Massachusetts Electric Company, Proposed Global Assumptions filing (May 12, 2014) ("Joint Utility Proposed Global Assumptions").

allowed to identify which benefits of their STIPs are not quantified and how these benefits have factored into the companies' analyses of their STIPs.

D. Stranded Costs

As discussed in Section II.B.2 above, as part of the approval of their STIPs, the Department should approve distribution companies' proposals for how they will recover the costs of stranded assets that they replace as part of their STIPs in order to make measurable progress toward one or more of the Department's four grid modernization objectives.

With regard to the stranded cost information that the companies are to provide in the Template, the Template should also include a time dimension to show when assets will be retired before the end of their useful lives. The companies should also propose amortization schedules and carrying charges for the undepreciated assets so that the Department can rule on cost recovery for such assets at the same time that it issues decisions on STIPs.

III. Comments on Business Case Summary Template

National Grid supports the Department's effort to promote a common analytical framework across the distribution companies. National Grid urges the Department to establish Requirements and a Template that focus on providing guidance to distribution companies regarding the business case benefit-cost analysis without being overly prescriptive and constraining distribution companies through the mandatory and strict application of a pre-defined template. Through more general guidance regarding the necessary approach to and components of a business case analysis the Department can promote a sufficient level of consistency across the distribution companies and ensure that the distribution companies address each element of a benefit-cost analysis that the Department deems necessary. However, requiring strict adherence to a specific template defined prior to either the Department or other stakeholders having begun to consider in detail the specifics of actual STIPs does not acknowledge that the distribution companies will likely have additional insights into the best set of and definitions for costs and benefits to quantify once they are further along the road of developing their STIPs and the associated business case analyses. National Grid suggests that the Department's filing requirements present the Template as a template that the distribution companies should adopt and refine as appropriate as they develop their STIPs and associated business case analyses.

National Grid supports the Department's recognition that additional categories of costs and benefits may need to be added to the Template when the distribution companies are analyzing the benefits and costs of their proposed STIP investments. This flexibility is important in order to ensure that benefits and costs that may not be foreseen at this time can in fact be included in the analysis if appropriate. National Grid also offers some specific comments on the different elements of the Template, below. These comments are based on National Grid's review of the Template prior to the company's having begun working on its STIP in earnest. As explained above, the distribution companies are likely to find additional improvements or refinements to the Template as they advance their STIPs and begin to work in detail on their business cases, and the Department's filing requirements should specifically grant the distribution companies discretion to refine their application of the Template as long as they follow the general guidelines provided in the filing requirements.

A. Key Definitions

The definition of "non-capitalized incremental O&M expenses" should not be limited to O&M expenses that arise after the grid modernization project is in commission, nor should they be limited to costs that are "re-occurring". Utilities will incur O&M costs related to their STIPs before STIP investments are "in commission" and likely will have related non-recurring costs as well. This definition should be revised to include O&M cost that occur before an investments is "in commission" and to include non-recurring costs as well.

B. List of Benefits, Functionalities, Technologies

Based on the Template Instructions and the structure of the Template Benefits worksheet, the Template seems to assume that there will be a simple one-to-one or one-to-many correspondence between Grid Mod Objectives, Actions/Impacts, Functionalities, Technologies/Devices/Systems and Benefits. This is likely to not be the case for a number of investments, however. For example, the 'Backhaul Communications System' will likely be mapped to many if not most functionalities, but that technology will not itself deliver any specific benefits; rather it will enable other technologies that do. Moreover, in some cases, a particular benefit is likely to be realized as a result of several grid modernization investments and new O&M activities working together in concert without distribution companies being able to apportion the benefit across different Technologies/Devices/Systems.[9] To ameliorate this potential complication the Department should consider re-structuring the Template Benefits section so that the logic of the worksheet flows in the opposite direction. Specifically, the business case analysis's consideration of benefits would more logically focus on a particular benefit and then define the Functionalities and Technologies/Devices/Systems that would enable that benefit. The Template should allow for a single benefit (with a single present value quantification) to be mapped to multiple Functionalities, Technologies/Devices/Systems, Grid Mod Objectives, and Actions/Impacts.

[9] This many-to-many mapping of benefits to technologies/functions is evident in Table 4-8 in the Electric Power Research Institute's *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, January 2010.

With respect to the list of benefits, "Improved Safety" should be added to the List of Benefits. This is a fundamental element of a utility company's business and is an important benefit to identify. Improved safety will further the Department's grid modernization goal of improved workforce and asset management. In addition, a category for "Other" should be added to the List of Benefits, Functionalities and Technologies (and to the List of Costs), which can be used to specifically list other benefits and costs identified.

There also are several listed benefits which the Department should clarify how they are defined or how they are to be valued, including "More streamlined moving procedures" and avoided greenhouse gas emissions compliance costs.

C. List of Costs

Under the "List of Costs" tab, the assignment of an Action/Impact to discrete costs could be problematic in some cases. For example, advanced meters will have a cost estimate that is not readily disaggregated to different Actions/Impacts, even though the cost of the meters enables many important Grid Modernization Actions/Impacts. In order to address this issue, the Template should allow for a particular Cost/Expense to be mapped to multiple Grid Mod Objectives, Actions/Impacts, Functionalities and Technologies/Devices/Systems.

An "Other" column also should be added to the List of Cost tab, and the Template should state that additional categories can be added. A column should be added to the "Costs" tab of the Summary Template for "Costs to be included in Cap Ex tracker?". Distribution companies can then select "Yes" or "No" in this column.

D. Stranded Costs

Please see National Grid's comments in Section II.B.2, *supra.*

E. Glossary

The definition of "Backhaul Communications Systems" should be revised to reflect that such a system not only can support advanced metering infrastructure, but also likely can be used to support other communications with other systems on the distribution grid (for example, a distribution automation system or a Volt-VAR optimization system. The definition could be revised to state "The infrastructure used to connect the Advanced Metering Infrastructure (AMI) head-end system to the AMI data collectors or access points, and/or used to communicate with other grid modernization technologies."

IV. Responses to Briefing Questions

A. Question 1: Common Analysis Methods – Discount Rate

Question 1: For each type of grid modernization investments, explain whether the 20-year Treasury Rate or the Company's weighted average cost of capital (WACC) would be the appropriate discount rate.

Response: National Grid reiterates its position in the Joint Utility comments to the cost-benefit working group on the appropriate discount rate.[10] In those comments, the Joint Utilities stated that the discount rate to be applied should be the Distribution Company's Weighted Average Cost of Capital ("WACC"), calculated using the Distribution Company's Return on Equity ("ROE"), approved as of the last distribution base rate case, and the year-end capital structure and after-tax weighted average cost of long-term debt from the Distribution Company's most recent FERC Form 1 filing. Because the discount rate includes the impact of the tax shield from using debt, cash flows used in the STIP's business case analysis should include no debt, reflect no interest on debt, and be computed on an after-tax basis. To illustrate the magnitude of the suggested discount rate, National Grid's Preliminary Annual Earnings Report for Year Ended

[10] Joint Utility Proposed Global Assumptions.

December 31, 2013 (submitted to the Department on May 1, 2014 in D.P.U. 09-39) indicates an after-tax WACC of 6.99 percent based on the Company's authorized capital structure and capital costs.[11] The WACC is the rate of return currently used in National Grid's capital expenditure tracking mechanism.[12]

The use of the utility WACC as the discount rate is consistent with the practice of utilities and regulators in other jurisdictions who have previously conducted advanced metering and smart grid benefit-cost analyses. To illustrate this point, the table below shows the discount rates used in the benefit-cost analyses that the Department noted having consulted in preparing its benefit-cost analysis model.[13] The only analysis in the table that used a Treasury Rate for its discount rate was that of Ameren Illinois. However, the Illinois Commerce Commission rejected Ameren's choice of discount rate as "inappropriate."[14]

[11] This calculation is intended only to estimate the magnitude of the company's after-tax WACC and not to propose a specific discount rate for use in the company's business case. This after-tax WACC estimate is based on the authorized capital structure and cost of capital rather than the FERC Form 1 data because the company's FERC Form 1 filing for 2013 is not yet available. The after-tax WACC = [authorized cost of common equity] * [common equity ratio] + [cost of preferred equity] * [preferred equity ratio] + [1 – tax rate] * [long-term debt cost] * [debt ratio] = [10.35%]*[49.99%] + [0.14%]*[4.44%] + [100% – 39.23%]*[5.96%]*[49.87%].
[12] M.D.P.U. No. 1231, Massachusetts Electric Company and Nantucket Electric Company Revenue Decoupling Mechanism, at Sheet 1.
[13] The Department noted these analyses in D.P.U. 12-76, Memorandum regarding the Benefits-Cost Analysis Working Group: Appendix A, March 25, 2014.
[14] Illinois Commerce Commission Order on Rehearing in Docket No. 12-0244, December 5, 2012, at 24. The Illinois Commerce Commission did approve Ameren's advanced metering plan as "cost beneficial," based upon the finding that the NPV for the project remained positive at an 8.2% discount rate.

Benefit-Cost Analysis	Discount Rate	Notes
Ameren Illinois[15]	3.62%	20-year Treasury Rate[16]
Portland General Electric[17]	5.17%	"cost of capital"[18]
BC Hydro[19]	8.00%	Utility WACC[20]
Baltimore Gas & Electric[21]	8.49%	Utility WACC[22]

Moreover, a recent compilation by Synapse Energy Economics of the discount rates used in evaluating advanced metering and smart grid projects covered an additional seven utilities across five jurisdictions, and found that those discount rates ranged from 6.69 percent to 8.954 percent.[23] This evidence shows that use of a Treasury Rate for the discount rate in grid modernization business case analysis would not be in keeping with industry best practices.

The 20-Treasury Rate is not the appropriate rate to use as the discount rate for grid modernization investments. In 2009, the Department endorsed the use of the 20-year Treasury Rate as the discount rate in updating the Energy Efficiency Guidelines for cost-effectiveness

[15] Ameren Illinois, Advanced Metering Infrastructure (AMI) Cost/Benefit Analysis (June 2012), available at: http://bit.ly/1AXqhS6.

[16] See Section 8.1 General Assumptions of Ameren IL report.

[17] Portland Gas & Electric, PGE Advice No. 07-08, UE 180 PGE Exhibit 800, Direct Testimony of Stephen Hawke, Bruce Carpenter and Alex Tooman, March 7, 2007, available at: http://edocs.puc.state.or.us/efdocs/UAA/ue189uaa142421.pdf.

[18] See Attachment 2 to PGE filing. The filing provides no further details on the discount rate.

[19] BC Hydro, *Smart Metering and Infrastructure Program Business Case* (December 2011), available at: http://1.usa.gov/1r0VJrQ.

[20] The company explains that: "BC Hydro's discount rate (Weighted Average Cost of Capital) for business cases is based on BC Hydro's deemed capital structure, the allowed rate of return on equity—both of which are approved by the British Columbia Utilities Commission—and the forecasted average cost of debt. The Weighted Average Cost of Capital for F2011 is presently set at 8 per cent, and includes a 2 per cent rate of inflation." See Appendix 6 of the BC Hydro report.

[21] Baltimore Gas & Electric, Case No. 9208, Public Service Commission of Maryland, *The Smart Grid Initiative Business Case Advanced Metering and Smart Energy Pricing Program*, July 13, 2009, available at:http://webapp.psc.state.md.us/Intranet/casenum/CaseAction_new.cfm?CaseNumber=9208.

[22] Baltimore Gas & Electric explains that the discount rate reflects its last authorized rate of return.

[23] Direct Testimony of J. Richard Hornby of Synapse Energy Economics on Behalf of the People of the State of Illinois in Illinois Commerce Commission Docket No. 12-0244, August 24, 2012.

tests. The Department arrived at this conclusion based on two arguments, neither of which is applicable here. First, the Department noted that the energy efficiency cost-effectiveness test included customer costs in addition to utility costs, making the utility WACC inappropriate for the discount rate.[24]Second, the Department explained that "energy efficiency expenditures are low-risk investments from the perspectives of both the distribution company and the ratepayers" and that utilities recover energy efficiency expenditures "within the year that they are spent and, thus, there is little risk and few carrying costs associated with these expenditures, unlike the risk and carrying costs that are associated with a distribution company's capital expenditures."[25] Neither of these arguments applies to the STIP business case analysis, which addresses the capital investments (as well as associated capitalized overhead costs and any relevant non-capitalized incremental O&M costs) that utilities will make as part of their grid modernization plans.

The use of the utility WACC for the discount rate in advanced metering and smart grid benefit-cost analyses in fact conforms to best practices for utility resource planning with energy efficiency. These best practices recommend use of the utility WACC (or a higher discount rate reflective of customers' cost of capital) in all cost-benefit tests except when considering very broad societal costs and benefits.[26] Such a broad social perspective is not consistent with the focus of the STIP business cases.

STIP business cases also should not apply different discount rates to different cost or benefit streams, such as those associated with different grid modernization investments. Benefit-cost analysis guidance from the U.S. Environmental Protection Agency explains: "[i]t is

[24] DPU Order in 08-50-A, March 16, 2009, at 21.
[25] *Id.*
[26] See Table 5-3 in *Guide to Resource Planning with Energy Efficiency: A Resource of the National Action Plan for Energy Efficiency*, November 2007.

important that the same discount rate be used for both benefits and costs because nearly any policy can be justified by choosing a sufficiently low discount rate for benefits, by choosing sufficiently high discount rates for costs, or by choosing a sufficiently long time horizon."[27] Any variations in the level of risk or uncertainty related to different cost and benefit streams are best addressed explicitly via sensitivity analyses based on ranges of expected costs and benefits rather than through the use of multiple discount rates within a single business case analysis.[28]

B. Question 2: Double Counting

Question 2: Explain whether the proposed Filing Requirements and Template are adequate to prevent double counting of costs and/or benefits. If not, provided recommendations for how these materials could be modified to address this concern.

Response: As National Grid is conducting its analysis of the costs and benefits of its STIP, it will work to ensure that benefits and costs are not double counted. There may be overlap in the benefits that different technologies provide, and in order for some technologies to provide benefits there may be other technologies that are prerequisites to be installed (e.g., a two-way communication system would need to be installed in order to communicate with AMI meters). The suggestions above regarding the Template Benefits and Costs worksheets will simplify the effort to avoid double counting. Companies should describe in their business cases how they apportioned aggregate projected benefits of a certain type among multiple rows in the Template where they did so, as well as their general approach to avoiding double counting of costs and benefits.

[27] U.S. Environmental Protection Agency, *Guidelines for Preparing Economic Analyses,* Chapter 6: Discounting Future Benefits and Costs, December 2010, at 6-2.
[28] Ringer, Mike, *Discounting Future Fuel Costs at a Social Discount Rate*, California Energy Commission Staff Paper, August 2008, at 12.

C. Question 3: Common Assumptions

Question 3: Explain whether it would be possible to leverage data from any studies in other D.P.U. dockets to calculate any of the common assumptions and corresponding values (e.g., dockets related to energy efficiency plans or long term contracts for renewable energy). Please describe all relevant examples, any challenges to levering such studies for use in GMPs, and whether a new study would instead be required for GMPs.

Response: It may be possible to leverage data from information filed in other D.P.U. dockets. For example, the 2013 Avoided Energy Supply Costs Study ("AESC 2013") could provide some guidance in terms of forecasts for energy prices, demand prices, demand reduction induced price effects ("DRIPE"), and the forecast of Renewable Energy Certificate ("REC") costs, although the results from the AESC 2013 or any other such studies would need to be updated to reflect the current wholesale markets and other current circumstances. The data and analysis from the AESC 2013 must be approached with caution, however, for the purposes of the STIP business case analyses. As the AESC 2013 report explains:

> [The AESC 2013] provides projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. In order to determine the value of efficiency programs, AESC 2013 provides projections of avoided costs of electricity and natural gas in each New England state for a hypothetical future, the "Base Case," in which no new energy efficiency programs are implemented in New England from 2014 onward. [T]he projections . . . thus do not reflect the actual market conditions and prices likely to prevail in New England in an actual future with significant amounts of new efficiency measures.[29]

As indicated above, a critical consideration regarding the AESC 2013 is that the Report's estimates of avoided costs from energy savings and peak demand reductions are measured against the wrong baseline for purposes of the STIP business case analysis—i.e., a hypothetical

[29] Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2013 Report*, Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, July 12, 2013, at 1-1.

forecast of energy market factors that assumes no new Massachusetts or other New England energy efficiency efforts. In contrast, a business case analysis should measure the benefits and costs of a STIP against a baseline that does reflect the energy efficiency and other energy programs (e.g., solar incentives) expected to be in place during the timeframe for the analysis, and many of these energy efficiency and other programs will be incremental to those assumed in the AESC 2013 "Base Case." Any analysis of benefits from grid modernization will have to consider the impacts from these programs first before determining the incremental benefit from grid modernization efforts. Further in-depth evaluation of existing studies will be required to determine the extent to which utilities could use studies like AESC 2013 as a starting point for STIP business case analyses.

Additionally, it may be possible to leverage data from the analyses conducted for long-term contracts pursuant to Section 83A, though again any such data like would need to be updated to reflect current circumstances.

D. Question 4: Granularity of Data

Question 4: Describe the level of granularity that would be appropriate for GMP filings in terms of quantified costs and benefits. Please provide examples.

Response: It is likely that the distribution companies will be able to quantify different costs and benefits to varying levels of granularity in their supporting work papers for the Template. Certain benefits and costs will be amenable to more detailed analyses whereas others will more high-level assumptions and inputs; for example, this may be the case for benefits that depend in large part on customer uptake of technologies or participation in new rate designs. Requiring a high degree of granularity in the business case is likely to suggest a false sense of precision for certain benefits and costs whose quantification is necessarily uncertain. The Template and any supporting business case narrative document should present sufficient granularity to allow the

Department and other stakeholders to evaluate the distribution companies' STIPs without overwhelming parties with excessive detail. To the extent that particular costs or benefits necessitate additional inquiry into their specific calculations, the distribution companies can provide additional information regarding the relevant aspects of their business case analyses at the Department's request. Annual estimates of costs and benefits, for example, are likely sufficiently granular to support business case evaluation.

E. Question 5: Unquantifiable Benefits

Question 5: Does the Department need to provide any additional guidance on the assessment or ranking of unquantifiable benefits to ensure that all companies evaluate these benefits in a similar manner? If so, provide suggestions as to what such guidance might entail.

Response: National Grid does not believe that additional guidance on the assessment or ranking of unquantifiable benefits is needed. Each distribution company has a different existing distribution system, and each company is likely to make different proposals in their STIPs that will create different benefits, within the context of the systems from which they are starting. Each company will assess what the relative benefits will be for their customers in their STIPs, and their proposed STIPs will have to be evaluated in this light.

V. Conclusion

National Grid appreciates the opportunity to comment on the proposed Requirements and Template, and looks forward to the Department's final order on the business case analysis for the distribution companies' proposed STIPs. National Grid also reserves the right to reply to comments filed by others on these matters.

Respectfully submitted,

Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid

By their attorney,

Melissa G. Liazos

____

Melissa G. Liazos
Senior Counsel
National Grid
40 Sylvan Road
Waltham, MA 02451
Telephone: 781-907-2108
Email: melissa.liazos@nationalgrid.com

Dated: August 22, 2014

Grid Modernization Business Case Filing Requirements

I. INTRODUCTION AND PURPOSE OF BUSINESS CASE

This document provides guidance on the business case that an electric distribution company must file as part of its grid modernization plan ("GMP"). See Modernization of the Electric Grid, D.P.U. 12-76-B at 15-17. The business case will be a central component of each company's short-term investment plan ("STIP"), which addresses the capital investments a company proposes to make over the first five years of the GMP. The business case will serve as the vehicle by which the Department and other parties will evaluate whether the benefits, both quantified and unquantified, justify the costs of the proposed STIP investments. In order to enable evaluation of all appropriate benefits and costs associated with a STIP, the business case should include capitalized overhead costs, as well as any non-capitalized incremental operations and maintenance ("O&M") costs that are integral to implementation of the STIP and achievement of its benefits.[1] We reiterate our conclusion in D.P.U. 12-76-B that these non-capitalized O&M costs are not eligible for pre-authorization or cost recovery through a capital expenditure tracker, but emphasize that such costs should be considered in the business case analysis.

II. BUSINESS CASE FILING REQUIREMENTS

A. Summary

Each company's STIP must include one composite business case that illustrates how the STIP investments will achieve measurable progress towards the Department's four grid

[1] An example of such non-capitalized incremental O&M costs are incremental O&M costs related to marketing, education, and outreach with respect to time varying rate programs. See D.P.U. 12-76-B at 23-25; Time Varying Rates, D.P.U. 14-04-B, at 17-18 (June 12, 2014).

modernization objectives. The business case will include four primary components, each discussed in more detail below. Additionally, each company must present an overall assessment of whether its business case justifies the proposed investments.[2] The four primary components of the business case are as follows:

1. Goals, scope and scale, drivers for investments;
2. Detailed descriptions of the proposed investments, and identification and quantification of all quantifiable benefits and costs associated with the STIP;
3. Identification of all difficult to quantify/unquantifiable benefits and costs; and
4. Stranded cost analysis.

In addition, the companies must complete the Business Case Summary Template ("Template"), attached, which includes summary information and analysis regarding quantifiable and unquantifiable benefits and costs as well as analysis of stranded costs. Distribution companies may add additional benefits and costs to the proposed template, and may adapt the template based on their learnings as they develop their STIP proposals.

B. Goals, Scope and Scale, and Drivers

This section will include a clear statement of a distribution company's reasoning and rationale for its proposed STIP investments. Each company must: (1) identify the technology solutions considered and selected; (2) describe how the STIP proposal will achieve measureable progress in meeting the Department's grid modernization objectives, including advanced metering functionality, while also enabling the achievement of state and Department policy objectives; (3) provide information on the scope and scale of the technology proposed;

[2] As discussed in D.P.U. 12-76-B, a company may also propose an alternative STIP with a corresponding business case if the benefits of implementing advanced metering functionality within five years do not justify the costs. D.P.U. 12-76-B at 17.

and (4) discuss any alternative investments considered and the rationale for choosing the proposed suite of investments.

C. Project Descriptions and Analysis of Quantifiable Benefits and Costs

As part of the business case, companies must provide an explanation of and background material for all components of the STIP, including a detailed description of all proposed investments and a deployment schedule. This section should also include an itemization and analysis of all quantifiable costs and benefits.

1. Projected Costs

For all STIP investment categories, a company must provide cost estimates, using vendor quotes wherever possible. Also, a company must identify any incremental STIP capital investments for which it plans to seek cost recovery in a later capital expenditure tracker proceeding.[3] When calculating costs, the companies must include all costs related to proposed capital investments, including capitalized overhead costs, as well as any appropriate incremental, non-capitalized O&M costs. It is not expected that each company will use every cost category contained in the Template. The companies should provide all costs within the format set forth in the Template, and provide supporting documentation to justify all cost estimates.[4] Companies may provide a range of costs where appropriate, and may list additional categories of costs where necessary.

---

[3] In D.P.U. 12-76-B at 18, the Department describes its use of "incremental."

[4] All information provided within the Template must be presented in active spreadsheets to permit the Department and other parties to fully review calculations, assumptions, scenarios, sensitivities, etc.

2. Projected Benefits

Each company must describe and provide documentation supporting the quantifiable benefits of its proposed STIP investments. This description must identify the beneficiaries of the investment using the categories defined in the Template, as well as include descriptions of the actions that are necessary to achieve the benefits. As with costs, this analysis should include only benefits that are incremental to current investments. Companies may include a range of expected benefits, where appropriate, as well as provide additional benefit categories if necessary.

The companies must identify all benefit categories to which they are ascribing quantifiable benefits within the format set forth in the Template. It is not expected the each company will use every benefit category contained in the Template. In calculating quantifiable benefits and costs, the companies must use common assumptions where possible. Specifically, the companies must jointly develop the assumptions and values set forth in Table 1 below.[5] For any company-specific assumptions and values used, the company should provide a description of the method used to calculate those benefits (and/or costs) and any source(s) it relied upon to make the assumption.

[5] As necessary, the companies may jointly conduct a study or leverage a similar effort to develop these assumptions and values in a transparent manner.

Table 1: Common Assumptions and Values
• Rate of Inflation
• Energy forecast (kWh)
• Demand forecast (kW)
• Forecast of energy prices
• Forecast of capacity prices
• Forecast of demand reduction induced price effects[6]
• Forecast of Renewable Energy Certificate ("REC") costs

The Department recognizes that the values upon which a company relies in its analyses will vary due to factors such as each company's cost structure and the specific STIP investments proposed. However, the companies must use a standard method, across all companies, regarding each of the following:

Table 2: Common Analysis Methods	
Treatment of Stranded Costs	The analysis of benefits and costs included in a STIP (i.e., as reflected in the Benefit and Cost tabs in the Template) will apply only to the benefits and costs that are incremental to existing plant, i.e., are related to the new STIP investments. The undepreciated value of existing assets will not be included in this analysis. However, this residual asset value of the investment not included in the analysis of benefits and costs will be presented as part of the overall business case.
Discount Rate	Weighted average cost of capital~~ and/or 20-year treasury, as appropriate~~
BCA Time Horizon	The cumulative benefits and costs from a prospective investment alternative should be evaluated over 15 years, with a terminal value appropriate to the technology under consideration.~~Projected depreciable life of the technology/asset~~

6 Demand reduction induced price effects refer to the changes in prices in the wholesale markets for capacity and energy resulting from the reduction in quantities of capacity and energy required from those markets due to the impact of electric and capacity reductions. This is also referred to as "market price suppression." See, e.g. Rick Hornby et al., Avoided Energy Supply Costs in New England: 2013 Report at 1-18 (Synapse Energy Economics, Inc. July 12, 2013), available at http://www.synapse-energy.com/Downloads/SynapseReport.2013-07.AESC.AESC-2013.13-029-Report.pdf; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-54, at 108-133 (2010).

Sensitivity Analyses	Each company must include sensitivity analyses for a limited set of variables in order to arrive at a reasonable range of quantifiable benefits and/or costs. Variables that are best suited for a sensitivity analysis are those for which a small change in an assumption can lead to a large change in the resulting output of a calculation. In addition, benefit categories that comprise a significant component of costs or benefits and the magnitude of which are difficult to predict could be well suited to a sensitivity analysis.

All quantifiable costs and benefits should be summed and reported in present value terms using the discount rate discussed above.

D. Analysis of Unquantifiable Benefits and Costs

Each company's business case must evaluate the full range of benefits that result from its investment plan. The Department recognizes that many of these benefits may be either difficult to quantify or unquantifiable. In particular, we note that many benefits from grid modernization that will accrue directly to ratepayers are difficult to quantify. In addition, as discussed in D.P.U. 12-76-B at 9, the Department sees grid modernization as an important means for advancing state policy goals and statutory requirements, and expects the companies to consider this benefit in their business case analysis.[7] All such benefits must be fully described in the business case supporting the proposed STIP investments. Difficulty in

[7] See, e.g., 225 C.M.R. § 14.00 (Renewable Portfolio Standard, which promotes renewable energy and implements state goal to interconnect 1,600 MW of solar generation by 2020); An Act Relative to Green Communities, St. 2008, c. 169 (statewide energy efficiency and demand response goals); An Act Establishing the Global Warming Solutions Act ("GWSA"), St. 2008, c. 298, codified as G.L. c. 21N, § 3 (greenhouse gas emissions reduction requirements); Executive Office of Energy and Environmental Affairs, Global Warming Solutions Act 5-Year Progress Report at 47 (December 30, 2013); the Department's service quality and emergency response standards; and the Department's distributed generation interconnection standards. We expect companies to describe how they took into account the benefits of meeting state policy goals in developing their STIP proposals.

quantifying a benefit does not lessen its significance relative to more easily quantifiable benefits. Within the Template, each company must define the benefit categories that the company considers in the business case but is unable to quantify. Each company must demonstrate how it factors these benefits into its overall analysis of its proposed STIP investments.

Difficult to quantify benefits will likely include benefit categories for which there is a quantifiable impact on either a distribution company or its customers, but the monetary value of the impact is unknown at this time (e.g., reliability improvements). In these instances companies must quantify the impact to the best of their ability, but are not required to quantify the monetary value of that impact.

In its analysis of unquantifiable benefits, a company must identify both the benefit category and the entity or entities to which the benefit will accrue. Each company must provide an analysis of the weight (e.g. low, medium, high) that it attributes to each unquantifiable benefit included within the Template,[8] as well as a narrative explanation of its analysis, including supporting documentation whenever possible. Further, a company should provide some discussion of how its assessment of difficult to quantify or unquantifiable benefits impacted evaluation of other potential investments that it did not ultimately propose in its STIP.

E. Stranded Costs

In assessing the costs and benefits of new investments contained in the STIP (i.e., as reflected in the Benefits and Costs tabs in the Template), a company may not include stranded

---

8 This is reflected in columns M and N in the Benefits tab in the Template, which address relevance to state policy goals and impact on grid modernization objectives.

costs of existing or historic capital equipment that the company proposes to replace before that equipment is fully depreciated because these are not costs or benefits associated with new investments. However, the Department recognizes that the magnitude of stranded costs may inform a company's business case and the timing of proposed investments, and that companies will need a way to recover these costs. Therefore, companies must include an analysis of the undepreciated costs associated with existing/historic capital equipment that the company proposes to replace as a result of its proposed STIP investments.[9]

Each company must provide the required data in the Stranded Cost tab of the Template in analyzing the financial implications of any stranded asset. Each company must provide an analysis of its proposed treatment for each stranded asset including any undepreciated costs to be recovered, proposed amortization period, rate of return and carrying charges (existing and future) that it expects would apply. We expect each company to provide a narrative regarding how the estimated stranded costs impact the overall business case. Approval of a company's STIP and GMP will include approval of a company's proposal for recovery of the undepreciated costs of stranded assets and carrying charges.

[9] If a utility retires plant before the end of its useful life the Department may recognize the retirement as an extraordinary loss and allow recovery of the undepreciated balance through amortization. Milford Water Company, D.P.U. 12-86, at 88-92 (2013) (retired water treatment facilities); Bay State Gas Company, D.T.E. 05-27, at 197-200 (2005) (discontinued meter reading technology); Hutchinson Water Company, D.P.U. 85-194, at 11 (1986) (prematurely abandoned well and fire hydrants). See also Fitchburg Gas and Electric Light Company, D.P.U. 19084, at 10-12 (1977) (finding that retired generating plant was abnormal retirement warranting the use of abandoned property accounting), aff'd, Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 571 (1978). Companies should only seek such treatment for extraordinary losses consistent with the Department's ratemaking practice.

THE COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid Grid Modernization	)	D.P.U. 12-76

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document in the above-referenced docket upon all parties of record in this proceeding in accordance with the requirements of 220 C.M.R. 1.05 (Department's Rules of Practice and Procedure), by hand delivery and/or E-Filing.

MASSACHUSETTS ELECTRIC COMPANY and
NANTUCKET ELECTRIC COMPANY
each d/b/a NATIONAL GRID

Melissa G. Liazos
National Grid
40 Sylvan Road
Waltham, MA 02451
Phone: (781) 907-2108
Email: melissa.liazos@nationalgrid.com

Date: August 22, 2014

Confidential Attachment DIV 5-3-3 – REDACTED INFORMATION

Attachment DIV 5-3-3 [CONFIDENTIAL] contains a benefit-cost analysis of the Company's proposed advanced metering functionality (AMF) deployment proposal for the Rhode Island only implementation scenario. The Company has requested protective treatment of this file in its entirety.

Confidential Attachment DIV 5-3-4 – REDACTED INFORMATION

Attachment DIV 5-3-4 [CONFIDENTIAL] contains a benefit-cost analysis of the Company's proposed advanced metering functionality (AMF) deployment proposal for the joint Rhode Island and New York Niagara Mohawk implementation scenario. The Company has requested protective treatment of this file in its entirety.

Division 5-4 SUPPLEMENTAL

Request:

For each benefit-cost analysis included in the rate case filing, please use a discount rate equal to the discount rate that is currently used for modeling the cost-effectiveness of the Company's energy efficiency programs. Please provide all workpapers, workbooks, and calculations in machine-readable format with formulas intact.

Response:

The Company did not re-run the benefit-cost analyses included in its rate case filing using the discount rate that is currently used for modeling the cost-effectiveness of energy efficiency programs, as the use of such an alternative discount rate will produce misleading results. Please refer to the Company's response to Division 5-3 for an explanation of why the Company's weighted average cost of capital is the appropriate discount rate for estimating the net present value of the proposed Power Sector Transformation investments.

(This response is identical to the Company's response to Division 1-4 in Docket No. 4780).

Supplemental Response:

Please see Attachment DIV 5-4-1 CONFIDENTIAL, Attachment DIV 5-4-2 CONFIDENTIAL, and Attachment DIV 5-4-3. Attachment DIV 5-4-1 CONFIDENTIAL contains the benefit-cost analysis (BCA) of the Company's proposed advanced metering functionality (AMF) deployment proposal for the Rhode Island only implementation program scenario, using an alternative real discount rate of 0.27 percent. Attachment DIV 5-4-2 CONFIDENTIAL contains the BCA of the Company's proposed AMF deployment proposal for the joint Rhode Island and New York Niagara Mohawk Power Corporation (Niagara Mohawk) implementation scenario, using an alternative real discount rate of 0.27 percent.

Attachment DIV 5-4-3 contains the BCAs for the Company's proposed Electric Transportation Initiative, Electric Heat Initiative, Energy Storage Investments, Company-Owned Solar Facilities, and Income Eligible Rewards Program, using an alternative real discount rate of 0.27 percent.

Please note that the alternative BCAs provided as attachments to this response and the summary of results shown below in Table 1. AMF BCA Summary by Implementation Scenario, Participation and Savings Scenario, and Discount Rate and Table 2. BCA Summary by Investment Category and Discount Rate, as well as the BCA results provided in the Company's supplemental response to Division 5-3, introduce multiple alternative sets of BCA results for each proposed investment into the record in this proceeding. The Company presents these alternative BCA results solely to provide the information requested by the Division of Public Utilities and Carriers, but does not view these requested results as valid or appropriate to determine the best use of customer funds. The Company is prepared to substantiate and defend the validity of the BCA results used by the Company in the proposed Power Sector Transformation Plan, as filed.

Table 1. AMF BCA Summary by Implementation Scenario, Participation and Savings Scenario below compares the Societal Cost Test (SCT) benefit-cost ratios originally filed in the Power Sector Transformation Plan using a real discount rate equal to the Company's after-tax WACC (7.5 percent) to the benefit-cost ratios that result when the alternative real discount rate of 0.27 percent is used. The results are shown for the proposed AMF deployment under the Rhode Island Only and Joint Rhode Island and New York Niagara Mohawk implementation scenarios, as well as under each of the four participation and savings scenarios. Across all scenarios, the use of the alternative 0.27 percent real discount rate increases the SCT benefit-cost ratios by 28 percent to 40 percent relative to the benefit-cost ratios originally filed in the Power Sector Transformation Plan.

Table 1. AMF BCA Summary by Implementation Scenario, Participation and Savings Scenario, and Discount Rate

Participation/Savings Scenario		**Scenario 1 Opt-In/ Low Savings**	**Scenario 2 Opt-In/High Savings**	**Scenario 3 Opt-Out/Low Savings**	**Scenario 4 Opt-Out/High Savings**
Implementation Scenario	**Discount Rate**	**SCT Benefit-Cost Ratios**			
Rhode-Island Only	7.5%	0.79	1.07	0.88	1.27
Rhode-Island Only	.27%	1.01	1.4	1.17	1.73
	% Change	28%	31%	33%	36%
Joint Rhode-Island & NY Niagara Mohawk	7.5%	1.07	1.44	1.19	1.71
Joint Rhode-Island & NY Niagara Mohawk	.27%	1.41	1.95	1.62	2.4
	% Change	32%	35%	36%	40%

Table 2. BCA Summary by Investment Category and Discount Rate below compares the SCT and Rate Impact Measure (RIM) benefit-cost ratios originally filed in the Power Sector Transformation Plan using a real discount rate equal to the Company's after-tax WACC (7.5 percent) to the benefit-cost ratios that result when the alternative real discount rate of .27 percent

is used. The results are shown for the proposed Electric Transportation Initiative, Electric Heat Initiative, Energy Storage Investments, and Company-Owned Solar Facilities and Income-Eligible Rewards Program. Across all investment categories, the use of the alternative 0.27 percent real discount rate increases the SCT benefit-cost ratios by 64 percent to 117 percent and increases the RIM benefit-cost ratios by 32 percent to 107 percent, relative to the benefit-cost ratios originally filed in the Power Sector Transformation Plan.

Table 2. BCA Summary by Investment Category and Discount Rate

Cost-Effectiveness Test	**SCT Benefit-Cost Ratios**			**RIM Benefit-Cost Ratios**		
Discount Rate	**7.5%**	**.27%**	**% Change**	**7.5%**	**.27%**	**% Change**
Investment Category Electric Transportation Initiative	1.03	2.24	117%	0.13	.17	32%
Electric Heat Initiative	1.12	2.08	86%	2.42	4.60	90%
Company-Owned Solar Facilities and Income Eligible Rewards Program	0.85	1.72	102%	0.63	1.30	107%
Energy Storage Investments	0.45	0.74	64%	0.49	.83	70%

(This response is identical to the Company's supplemental response to Division 1-4 in Docket No. 4780.)

Prepared by or under the supervision of: Robert Sheridan

Confidential Attachment DIV 5-4-1 – REDACTED INFORMATION

Attachment DIV 5-4-1 [CONFIDENTIAL] contains a benefit-cost analysis of the Company's proposed advanced metering functionality (AMF) deployment proposal for the Rhode Island only implementation scenario. The Company has requested protective treatment of this file in its entirety.

Confidential Attachment DIV 5-4-2 – REDACTED INFORMATION

Attachment DIV 5-4-2 [CONFIDENTIAL] contains a benefit-cost analysis of the Company's proposed advanced metering functionality (AMF) deployment proposal for the joint Rhode Island and New York Niagara Mohawk implementation scenario. The Company has requested protective treatment of this file in its entirety.