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+OF COUNSEL

September 11, 2012

<u>VIA ELECTRONIC FILING</u>
Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1-A
Washington, DC 20426

Re: New York Association of Public Power v. Niagara Mohawk Power Corporation d/b/a National Grid, Docket No. EL12-_____-000

Dear Secretary Bose:

Pursuant to section 206 of the Federal Power Act ("FPA")[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[2] the New York Association of Public Power ("NYAPP" or "Complainant") hereby files a complaint ("Complaint") against Niagara Mohawk Power Corporation d/b/a National Grid ("NMPC") seeking an order to reduce the 11.5 percent return on equity ("ROE") used in calculating rates for transmission service under the New York Independent System Operator, Inc.'s ("NYISO") Open Access Transmission Tariff ("OATT") to a just and reasonable level at 9.49 percent, inclusive of a 50 basis point adder for participation in the NYISO, with a corresponding overall weighted cost of capital of 6.73 percent.

Please find the following materials attached hereto:

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1 16 U.S.C. §§ 824e and 825e.

2 18 C.F.R. § 385.206 (2010).

- Complaint
- Exhibit No. NYP-1 Testimony of Jonathan A. Lesser
- Exhibit No. NYP-2 Curriculum Vitae of Jonathan A. Lesser
- Exhibit No. NYP-3 List of Previous Commission Testimony
- Exhibit No. NYP-4 Pages 245-247 from Principles of Utility Corporate Finance
- Exhibit No. NYP-5 National Grid plc, "Results for the year ended 31 March 2012"
- Exhibit No. NYP-6, Sch. 1 Utility Proxy Group Screening
- Exhibit No. NYP-6, Sch. 2 "Sustainable" Earnings Growth Estimates
- Exhibit No. NYP-6, Sch. 3 I/B/E/S Earnings Growth Estimates
- Exhibit No. NYP-6, Sch. 4 Avg. Monthly High-Low Stock Prices and Dividend Yields
- Exhibit No. NYP-6, Sch. 5 DCF Analysis Results
- Exhibit No. NYP-7 Pages 188-190 from Principles of Utility Corporate Finance
- Exhibit No. NYP-8, Sch. 1 Attachment 1, Schedule 8 from NMPC OATT Filing of June 14, 2012, as filed
- Exhibit No. NYP-8, Sch. 2 Attachment 1, Schedule 8 from NMPC OATT Filing of June 14, 2012, as adjusted
- Exhibit No. NYP-9 Service List
- Exhibit No. NYP-10 Form of Notice

Should you have any questions or concerns, please do not hesitate to contact me.

Respectfully Submitted
/s/ Thomas L. Rudebusch
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Matthew R. Rudolphi
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cc: service list

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Association of Public Power,	)	
	)	
Complainant,	)	
	)	
v.	)	Docket No. EL12-_____-000
	)	
Niagara Mohawk Power Corporation d/b/a National Grid, and	)	
	)	
The New York Independent System Operator, Inc.	)	
	)	
Respondents.	)	

(filed September ___, 2012)

COMPLAINT OF THE NEW YORK ASSOCIATION OF PUBLIC POWER CHALLENGING BASE RETURN ON EQUITY

Pursuant to section 206 of the Federal Power Act ("FPA")[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[2] the New York Association of Public Power ("NYAPP" or "Complainant") hereby files this complaint against Niagara Mohawk Power Corporation d/b/a National Grid ("NMPC") seeking an order to reduce the 11.5 percent return on common equity ("ROE") used in calculating rates for transmission service under the New York Independent System Operator, Inc. ("NYISO") Open Access Transmission Tariff ("OATT") to a just and reasonable level at 9.49 percent, inclusive of a 50 basis point adder for participation in the NYISO, with a corresponding overall weighted cost of capital ("WACC") of 6.73 percent.

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[1] 16 U.S.C. § 824e

[2] 18 C.F.R. § 385.206 (2010).

As discussed below, the NMPC ROE currently reflected in the NYISO OATT rate is unjust and unreasonable. The Complainant requests that the Commission: (1) institute paper hearing procedures to investigate the ROE and establish a just and reasonable equity return to be reflected in rates for transmission service provided over facilities owned by NMPC under the NYISO OATT; (2) establish the earliest possible refund effective date (*i.e.*, the date of this Complaint), consistent with Commission policy; and (3) direct NMPC to make refunds reflecting the difference between transmission rates reflecting an 11.5 percent ROE and rates reflecting a just and reasonable ROE.

I. COMMUNICATIONS

All correspondence and communications to the Complainant in this docket should be addressed to the following individuals, whose names should be entered on the official service list maintained by the Secretary in connection with these proceedings:

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New York Association of Public Power
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II. THE PARTIES

A. Complainant

1. NYAPP is an unincorporated association of nine municipal electric utilities and four rural electric cooperatives located throughout New York State, serving approximately 500 MW of load. NYAPP was founded in 2005 in response to emerging opportunities and challenges on both the national and state levels in the electric utility industry. NYAPP's Members are "Load Serving Entities" as defined in the Commission's Regulations, 18 C.F.R. § 41.2(b)(2) and in Section 217(a)(2) of the Federal Power Act. Several NYAPP Members are located on transmission facilities owned by NMPC, including: Green Island Power Authority, Jamestown Board of Public Utilities, Salamanca Board of Public Utilities, Oneida-Madison Electric Cooperative, Inc. and City of Sherrill Power & Light. These NYAPP Members pay the NMPC Wholesale Transmission Service Charge ("TSC") under the NYISO OATT.

B. Respondents

2. NMPC is a New York combination gas and electric utility company, primarily engaged in the business of transmission and distribution of electricity as well as the distribution and transportation of natural gas in New York. NMPC is the wholly-owned principal utility subsidiary of Niagara Mohawk Holdings, Inc., which in turn is wholly-owned by National Grid USA ("National Grid"). National Grid is an indirect, wholly-owned subsidiary of National Grid plc, a company incorporated in England and Wales.[3] The United States business of National Grid plc is conducted through National Grid. NMPC's physical assets include over 6,000 miles of transmission lines. All of NMPC's bulk electric transmission facilities are subject to the

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[3] Through various subsidiaries and investments, National Grid plc is engaged in utility and non-utility operations principally in the United States and the United Kingdom. National Grid plc is not a public utility under the FPA because it does not directly own or operate FPA-jurisdictional facilities (or any other electric facilities), nor does it directly engage in the sale, transmission, or distribution of electric power in the U.S.

operational control of the NYISO. As such, NMPC recovers its transmission revenue requirement pursuant to provisions of the NYISO OATT. Under the NYISO OATT, NYISO Transmission Owners, including NMPC, retain the authority to make FERC filings to revise their individual company revenue requirements.[4] NMPC calculates its TSC on a monthly basis and bills transmission service customers in accordance with the NYISO OATT. Accordingly, NMPC is the real party in interest for purposes of this Complaint.[5]

3. The NYISO is a non-profit company that serves as the independent system operator for the state of New York. NYISO administers the New York energy markets and operates the New York bulk power system pursuant to the NYISO Market Administration and Control Area Services Tariff and the NYISO OATT. The NYISO is deemed to provide all transmission service in the New York Control Area. NMPC collects its TSC from transmission service customers under the terms of the NYISO OATT. NYAPP has named the NYISO as a respondent only because NMPC's ROE is a stated value in the NYISO OATT,[6] and any change in the stated ROE would required a tariff revision filing by the NYISO.

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4 *See* NYISO OATT, Attachment H, "Annual Transmission Revenue Requirement for Point-to-Point Transmission and Network Integration Transmission Service," Section 14.1.2.1.2.

5 *See, e.g., NSTAR Elec. & Gas Corp. v. FERC*, 481 F.3d 794, 803-804 (D.C. Cir. 2007); *NRG Power Marketing, Inc. v. New York Ind. Sys. Operation, Inc.*, 91 FERC ¶ 61,346 at p. 62,165 (2000).

6 *See* NYISO OATT, Attachment H-1, Schedule 8, line nos. 10 and 19.

III. INTRODUCTION

4. NMPC recovers its annual transmission revenue requirement through the NMPC TSC included in the NYISO OATT. The TSC is calculated using a formula rate contained in the NYISO OATT.[7] By June 14th of each year, NMPC recalculates the components that determine its annual transmission revenue requirement by applying the data inputs called for in the formula rate. This annual update is posted on the NYISO website and NMPC files it as an informational filing with the Commission. Certain components of the formula, including the authorized ROE, are stated values that can only be changed by the Commission pursuant to Section 205 or 206 of the Federal Power Act.[8]

5. NMPC's current ROE is 11.5 percent, inclusive of NMPC's participation in the NYISO, a figure which was established by settlement in Docket No. ER08-552 and accepted by the Commission on June 22, 2009.[9] This Complaint only challenges the ROE and does not address any incentive adders applicable to NMPC's rates, including the 50 basis point adder for NMPC's participation in the NYISO.

6. Due to changes in the capital markets since the NMPC Formula Rate Settlement, the 11.5 percent ROE is no longer just and reasonable. The attached testimony and exhibits of Jonathan A. Lesser, PhD, demonstrates that the current ROE is excessive and that a just and reasonable ROE for NMPC under current market conditions does not exceed 9.49 percent, inclusive of the 50 basis point adder for participation in the NYISO.

7. Based on this evidence, this Complaint provides sufficient evidence to demonstrate that the existing ROE is unjust and unreasonable. The Commission should institute

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[7] *See* NYISO OATT, Attachment H, Section 14.1.9.

[8] *See* NYISO OATT, Attachment H, Section 14.1.9.3.

[9] *See Niagara Mohawk Power Corp.*, 127 FERC ¶ 61,289 (2009) ("*TSC Formula Rate Order*").

an investigation into this matter and find that the ROE proposed by the Complainant is just and reasonable. This investigation should utilize a paper hearing process. The Commission routinely decides complex and controversial cases on the basis of the record in a paper hearing, including determination of an appropriate ROE for providing transmission service.[10]

IV. BACKGROUND

8. On February 11, 2008, as supplemented on May 30, 2008, NMPC submitted a filing under Section 205 of the Federal Power Act to replace its stated rates for its TSC with formula rates to become effective May 1, 2008. On July 29, 2008, the Commission accepted and suspended the proposed formula rates, to become effective October 1, 2008, subject to refund, and established hearing and settlement judge procedures.[11]

9. On April 6, 2009, NMPC, on behalf of the Settling Parties,[12] filed the Settlement intending to resolve all issues set for hearing in that proceeding. Among other things, the Settlement set forth the terms of a formula rate for the calculation of NMPC's transmission service charge under the NYISO OATT (the "Settlement TSC Formula Rate"), as well as procedures for the annual adjustment of certain data inputs to the formula rate. On April 8, 2009, the Commission's Chief Administrative Law Judge granted NMPC's motion for interim rate relief and allowed the Settlement TSC to be implemented on an interim basis effective as of January 1, 2009 ("Settlement Effective Date") pending approval by the Commission. In a letter

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[10] *See, e.g., Southern Cal. Edison Co.*, 131 FERC ¶ 61,020 (2010); *Northern Natural Gas Co.*, 125 FERC ¶ 61,127 at P 13 (2008); *Nevada Power Co. and Sierra Pacific Power Co. v. Enron Power Marketing, Inc.*, 125 FERC ¶ 61,312 at P 29, n.67 (2008); and *Southern Cal. Edison Co.*, 92 FERC ¶ 61,070 (2000).

[11] *Niagara Mohawk Power Corp.*, Order Accepting and Suspending Formula Rate Subject to Refund and Establishing Hearing and Settlement Judge Procedures, 124 FERC ¶ 61,106 (2008)("*July 29 Order*"). Certain Settling Parties requested rehearing of aspects of the July 29 Order. On February 25, 2009, the Commission issued an Order that denied rehearing in part and granted rehearing in part. 126 FERC ¶ 61,173 (2009).

[12] The signatories consist of NMPC, NYAPP and the following entities: Allegheny Electric Cooperative, Inc., the City of Cleveland, Ohio, Multiple Intervenors, Municipal Electric Utilities Association of New York State, New York Municipal Power Agency, New York State Electric & Gas Corporation, and Rochester Gas & Electric Corporation ("Settling Parties").

order issued June 22, 2009, the Commission issued the *TSC Formula Rate Order*, approving the Settlement and on July 24, 2009, NMPC issued required refunds to customers.

10. In accordance with the NYISO OATT, NMPC is directed to calculate each year new values for its transmission Revenue Requirements ("RR"), control center costs ("CCC") and billing units ("BU") components of the Settlement TSC Formula Rate based on updated Data Inputs. NMPC is further directed to prepare an Annual Update that reflects the revised Data Inputs, the resulting RR, CCC, and BU components, and certain supporting information. According to Section 14.1.9.4 in Attachment H to the NYISO OATT, NMPC's ROE is a stated rate of 11.5 percent inclusive of a 50 basis point adder for NMPC's participation in the NYISO. This Complaint challenges NMPC's state ROE and is not a part of the Annual Update review process.

V. DISCUSSION

A. Applicable Standards

11. All rates for jurisdictional service under the FPA must be just and reasonable.[13] Where a complainant challenges a previously-approved rate under section 206 of the FPA and proposes a new one, the Commission has stated that complainants must satisfy a two-part burden of proof by showing that: (1) the existing rate is unjust and unreasonable; and (2) a proposed replacement rate is just and reasonable.[14] This Complaint provides sufficient evidence both to institute an investigation into the justness and reasonableness of the ROE and to find that the new rate proposed in this Complaint is just and reasonable.

12. A just and reasonable rate of return for a utility is one that does not exceed the level required to assure confidence in the financial integrity of the enterprise, so as to maintain

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[13] 16 U.S.C. §§ 824d and 824e.

[14] *See, e.g., Louisiana Pub. Serv. Comm'n v. Entergy Corp.*, 132 FERC ¶ 61,003 at P 28 (2010).

its credit and to attract capital, and must be commensurate with returns on investments in enterprises with comparable risks.[15] The Commission has a well developed policy for establishing a just and reasonable ROE for transmission service, based on applying a discounted cash flow ("DCF") analysis to a proxy group of comparable risk companies.[16] As described below, the Complainant has applied the Commission's well-established ROE methodology to identify the appropriate ROE under current conditions for NMPC.

B. NYAPP's ROE Analysis

13. In order to determine whether the current ROE of 11.5 percent remains just and reasonable, Dr. Lesser performed a DCF analysis in compliance with the Commission's current policies.[17] Dr. Lesser began his analysis by selecting a group of proxy companies with risk profiles representative of the risks of NGPC. Pursuant to Commission precedent, Dr. Lesser selected a national group of electric utilities that met the following criteria: (1) are covered by the Value Line Investment Survey ("*Value Line*"); 2) neither announced a merger or acquisition within the six-month analysis period nor were involved in an ongoing merger or acquisition during that period; 3) have paid constant or increasing dividends for at least the past two years; 4) are covered by at least two generally recognized utility industry analysts, and which have long-term (5-year) earnings growth forecasts reported by Institutional Brokers; 5) have annual revenues of at least $1 billion; and 6) have an investment grade corporate credit rating within one "notch" of NMPC, which is currently rated "A-" by Standard and Poor's (*i.e.*, utilities having

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[15] *See Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-93 (1923).

[16] *See, e.g., Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 (2011); *Potomac Appalachian Transmission Highline, L.L.C.* ("*PATH*"), 133 FERC ¶ 61,152 (2010); *Atlantic Path 15, LLC*, 133 FERC ¶ 61,153 (2010); *Southern Cal. Edison*, 131 FERC ¶ 61,020 (2010); *Golden Spread Elec. Coop.*, 123 FERC ¶ 61,047 (2008).

[17] Exhibit No. NYP -1 at 13-23.

credit ratings between "BBB+" and "A").[18] This yielded a proxy group of sixteen electric utilities.[19]

14. Dr. Lesser began with the forty-nine electric utilities currently covered by *Value Line*. From those, Dr. Lesser initially eliminated six because of their ongoing or recently completed merger or acquisition activity: Central Vermont Public Service; Duke Energy; Progress Energy; NStar; Northeast Utilities; and CH Energy Group. Dr. Lesser then eliminated two utilities that lacked sufficient dividend history: El Paso Electric offered no dividends for several years prior to that offered in June 2011 and Empire District Electric suspended its dividend in the third quarter of 2011. As a next step Dr. Lesser eliminated three utilities with 2010 annual revenues of less than $1 billion. Finally, Dr. Lesser eliminated utilities with corporate ratings more than one notch above or below NMPC, which includes those with credit ratings of "A+" or above and utilities with credit ratings of "BBB" or below.

15. This left the following sixteen utilities, which make up the proxy group: Alliant Energy, CenterPoint Energy, Consolidated Edison, Dominion Resources, DTE Energy, Integrys Energy, NextEra, OGE Energy, Pepco Holdings, SCANA Corp., Sempra Energy, Southern Company, TECO Energy, Vectren Corp., Wisconsin Energy, and Xcel Energy.

16. The selection of the proxy group is consistent with the Commission's established rules, and the selected proxy group utilities are comparable in risk to NMPC. Dr. Lesser derives stockholders' required rate of return for the proxy group using FERC's one-stage DCF model. Dr. Lesser calculated the sustainable earnings growth estimates for each of the proxy companies using three steps. First Dr. Lesser used *Value Line* data to estimate the average earnings per

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[18] *So. Cal. Edison Co.*, 131 FERC ¶ 61,020 (2010) ("*So. Cal. Edison Co. I*") at P 51, *reh'g denied*, 137 FERC ¶ 61,016 (2011) ("*So. Calif. Edison Co. II*").

[19] Exhibit No. NYP-1 at 14.

share, dividends per share, and book value per share to calculate the internal growth. Then Dr. Lesser calculated the external growth by taking the average market value of each company's stock over the previous six months and dividing by the average book value. Finally Dr. Lesser calculated the external growth by using the *Value Line* forecast of outstanding shares in the 2015-2017 time frame to determine the annual rate of share growth as well as the forecast change in capital structure and total capitalization to reflect the growth adjustment factor.

17. Dr. Lesser relied on the I/B/E/S earnings growth rates as forecasted as of July 31, 2012, available from Thompson Reuters or Yahoo!Finance, since the six month period used to determine dividend yields was February 1, 2012 through July 31, 2012. Dr. Lesser relied on the adjusted daily closing stock prices as published by Yahoo!Finance to estimate the low and high stock prices for each month and relied on the quarterly dividend payment data published by *Value Line* for each of the proxy companies to estimate the high and low dividend yields.

18. In conformance with the methodology used in *So. Cal. Edison Co. I* for determining the minimum threshold DCF value, Dr. Lesser calculated the average of the monthly yields on BBB rated, long-term utility bonds for the six-month period from February 1, 2012 through July 31, 2012 as reported by Moody's. The average yield on A rated bonds for this period was 4.28% and the average yield on BBB rated bonds for this period was 5.01%. By adding 100 basis points above the average, Dr. Lesser established a minimum threshold DCF value of 5.28% for "A" and "A-" rate proxy group firms and 6.01% for "BBB+" rate proxy group firms.

19. Dr. Lesser's analysis shows the zone of reasonableness has a range between 6.38 percent and 10.75 percent. The current ROE of 11.5 percent is not within Dr. Lesser's proxy group zone of reasonableness under the Commission's DCF model. The median average of the

low and high values of the proxy group is 8.99 percent. Dr. Lesser explains that to establish a median ROE, the Commission prefers to first determine the average of each proxy companies' low and high DCF values and then calculate the median of the resulting range. Dr. Lesser also has calculated the median of the larger sample of thirty-two values that includes the low and high values for each company as 9.01 percent. Dr. Lesser explains that it is his opinion that this median of the entire sample has greater statistical validity, but that the 2 bp difference in the values, 8.99 percent *vs*. 9.01 percent, is *de minimis*. Dr. Lesser recommends an ROE value of 9.49% inclusive of the 50 basis point adder for membership in an ISO or RTO based on the 8.99% median calculation.

20. Dr. Lesser determined that the use of the median is appropriate because there is no specific evidence that NMPC has a business and financial risk profile that differs significantly from that of the firms in the proxy group.

C. The Current 11.5 Percent ROE under the NYISO Tariff Is Unjust And Unreasonable

21. The DCF analysis performed by Dr. Lesser shows that as a result of significantly changed economic circumstances since the ROE was established in the *TSC Formula Rate Order*: (1) the current 11.5 percent ROE is unjust and unreasonable; and (2) the just and reasonable ROE is 9.49 percent. Because the formula rates under the NYISO OATT are intended to track the NMPC's current costs, the revenues generated by this excessive fixed ROE go straight to the NMPC's bottom line at the expense of customers. Retaining the current ROE would result in a substantial overpayment to NMPC by consumers relative to Dr. Lesser's recommended ROE.

22. Dr. Lesser has also calculated that the affect of using a 9.49% ROE on NMPC's overall WACC and the required before-tax investment return. Dr. Lesser relied on the NYISO

tariff formula rate for calculating the cost of capital. The formula-based WACC is 7.73%. The resulting value for the before-tax return is $136,652,963. Because the formula for capital structure limits the percentage of common equity to no more than 50% of total capitalization and NMPC has an actual amount of common equity of 61.33%, Dr. Lesser reduced the equity capitalization percentage by 11.33% to reach the maximum of 50% and increased the long-term debt percentage by 11.33% to 49.53% in accordance with the NYISO OATT.[20] Dr. Lesser used these capitalization percentages for common equity, long-term debt and preferred equity in calculating the revised WACC value for NMPC. The resulting WACC for NMPC, using the 9.49% ROE and the formula-rate capitalization percentages and rates is an overall WACC of 6.73%. The impact of the 6.73% WACC Dr Lesser calculated on the before-tax investment return results in a reduction of $19,080,537.

23. This represents a $19 million annual overpayment to NMPC by transmission service customers. Such overpayments are unjust and unreasonable, because they are in excess of what is

> reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate under efficient and economical management, to maintain and supports its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[21]

As the Supreme Court has made clear, not even "a little unlawfulness is permitted" in setting jurisdictional rates.[22] NYAPP respectfully submits that NMPC rates incorporating the existing ROE are leading to far more than just "a little" overpayment.

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[20] *See* NYISO OATT, Attachment H-1, Schedule 8.

[21] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692 – 693 (1923).

[22] *FPC v. Texaco Inc.*, 417 U.S. 380 (1974).

D. The Commission Should Institute an Investigation Regarding the NMPC ROE through a Paper Hearing

24. The analysis performed by the Complainant, at a minimum, provides sufficient information to show that the current NMPC ROE under the NYISO OATT is unjust and unreasonable. Accordingly, the Commission should institute a proceeding under section 206 of the FPA to investigate whether the ROE is excessive and to determine a just and reasonable ROE.

25. The Complainant requests that the Commission conduct such investigation through "paper hearing" procedures. The Commission routinely decides complex and controversial cases on the basis of the record in a paper hearing when such a process is sufficient to resolve all issues of material fact.[23] Notably, the Commission has used paper hearings to determine an appropriate ROE for transmission service,[24] and even where the Commission has established full evidentiary hearings on ROE issues, it has rejected arguments that establishing an ROE always requires such trial-type procedures.[25]

26. In numerous recent decisions addressing ROEs for electric transmission companies or projects, the Commission has clarified and refined its ROE policy to such a degree that a trial-type evidentiary hearing is not necessary to address the issue. The Commission has addressed issues such as whether given companies are appropriately included in the proxy group based on a written record, that has not included either discovery or cross-examination. Likewise, the Commission's application of the DCF analysis is essentially mechanical and is (or should be) based on public information that can be readily verified (or discredited) by the other paper

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[23] *See, e.g., Northern Natural Gas Co.*, 125 FERC ¶ 61,127 at P 13 (2008); *Nevada Power Co. and Sierra Pacific Power Co. v. Enron Power Marketing, Inc.*, 125 FERC ¶ 61,312 at P 29, n.67 (2008).

[24] *See, e.g., Southern Cal. Edison Co.*, 131 FERC ¶ 61,020.

[25] *See PATH*, 133 FERC ¶ 61,152 at P 54.

hearing participants and the Commission.[26] Here, a paper hearing would be sufficient for the parties to develop the record on the appropriate ROE based on the Commission's well-articulated policies for calculating ROE. Importantly, a paper hearing would facilitate an earlier Commission decision and expedite relief to customers who are currently paying transmission rates reflecting an excessive ROE.

27. Alternatively, if the Commission is not inclined to grant relief on the basis of the pleadings, NYISO asks that this matter be set for an evidentiary hearing.

E. The Commission Should Establish the Earliest Possible Refund Effective Date

28. In cases where the Commission institutes an investigation on a complaint under section 206 of the FPA, section 206(b) requires the Commission to establish a refund effective date that is no earlier than the date the complaint was filed, but no later than five months after the filing date.[27] The Commission's general policy is to set the refund effective date at the earliest possible date, *i.e.*, the date a complaint is filed.[28] Consistent with its general policy, the Commission should establish the filing date of this Complaint as the refund effective date in its investigation of the ROE in order to provide maximum protection to consumers.[29]

V. RULE 206 REQUIREMENTS

29. NYAPP hereby provides the further information required by Rule 206.[30]

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[26] *See id.* at P 55, n.83.

[27] 16 U.S.C. § 824e(b).

[28] *See, e.g., Old Dominion Electric Cooperative and North Carolina Electric Membership Corporation v. Virginia Electric and Power Company*, 133 FERC ¶ 61,009 at P 36 (2010) (citing *Seminole Elec. Coop., Inc. v. Fla. Power & Light Co.*, 65 FERC ¶ 61,413, at p. 63,139 (1993); *Canal Elec. Co.*, 46 FERC ¶ 61,153, at p. 61,539, *reh'g denied*, 47 FERC ¶ 61,275 (1989)).

[29] *See id.*

[30] 18 C.F.R. § 385.206 ("Rule 206").

A. Good Faith Estimate of Financial Impact or Harm (Rule 206(b)(4)).

30. As described above and in Exhibit No. NYP-1, the Complainant estimates that reducing the ROE from 11.5 percent to a just and reasonable level of 9.49 percent would reduce transmission costs in New York by approximately $19 million annually.

B. Operational or Nonfinancial Impacts (Rule 206(b)(5))

31. The Complainant is not aware of any specific practical, operational or nonfinancial impacts resulting from the excessive ROE.

C. Whether the Matters are Pending in Any Other FERC Proceeding or Other Forum (Rule 206(b)(6))

32. The matters raised in this Complaint are not currently pending in any other Commission proceeding or in any other proceeding to which the Complainant is a party.

D. Documents Supporting the Complaint (Rule 206(b)(8))

33. In support of this Complaint, NYAPP has included the testimony, supporting exhibits and workpapers of Jonathan A. Lesser, PhD, President of Continental Economics, Inc.[31]

E. Alternative Dispute Resolution (Rule 206(b)(9))

34. NYAPP submits that it is unlikely that alternative dispute resolution ("ADR") procedures under the Commission's supervision would successfully resolve the issues raised in the Complaint until after a complaint had been filed and FERC had established a refund effective date. The Complainant is ready and willing to engage in ADR procedures for a limited time frame after the refund effective date is established. While the Complainant hopes this matter can be resolved through settlement, NYAPP is mindful that unproductive settlement discussions could serve to delay the adjustment of the ROE to a just and reasonable level.

VI. SERVICE AND NOTICE

[31] *See* Exhibit No. NYP-1.

35. In accordance with Rule 206(c), the Complainant has served a copy of this Complaint upon each of the Respondents simultaneous with the filing of the Complaint. The Complainant has also served copies of the Complaint upon the New York State Public Service Commission.[32]

36. In addition, the Complainant has asked the NYISO to distribute the Complaint to its e-mail distribution lists. Attached hereto as Exhibit NYP-10 is a Form of Notice suitable for publication in the *Federal Register* in accordance with Rule 206(b)(10).

VII. CONCLUSION

Based on the foregoing, NYAPP requests the Commission to: (1) institute paper hearing procedures to investigate the ROE used in calculating the transmission revenue requirements for NMPC for service under the NYISO OATT and establish a just and reasonable base return on equity; (2) establish the earliest possible refund effective date (*i.e.*, the date of this complaint), consistent with Commission policy; (3) direct NMPC to make refunds reflecting the difference between transmission rates reflecting an 11.5 percent ROE and rates reflecting a just and reasonable ROE, and (4) direct the NYISO to make a tariff filing to change the stated ROE value to a just and reasonable ROE as determined in this proceeding.

Respectfully submitted,
/s/ Thomas L. Rudebusch
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32 The complete list of parties that the Complainant served this Complaint is attached as Exhibit No. NYP-9.

Exhibit No. NYP-1

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Niagara Mohawk Power Company (d/b/a)	)	**Docket No. EL12-___-000**
National Grid	)	
	)	

PREPARED DIRECT TESTIMONY

OF

JONATHAN A. LESSER

ON BEHALF OF

NEW YORK ASSOCIATION OF PUBLIC POWER

September 11, 2012

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am the President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, NM 87047.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist specializing in litigation and market analysis in the energy industry. I have over 25 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government entities. I have provided expert testimony before numerous state utility commissions, before the Federal Energy Regulatory Commission ("FERC" or "the Commission"), before state legislative committees, and before international regulators.

Before founding Continental Economics, I was a Partner in the Energy Practice with the consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I hold MA and PhD degrees in economics from the University of Washington and a BS, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. Exhibit No. NYP-2 is a copy of my current curriculum vitae.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the International Association for Energy Economics, the Energy Bar Association, and the Society for Benefit-Cost Analysis.

Q. WHO IS SPONSORING YOUR TESTIMONY?

A. My testimony is sponsored by New York Association of Public Power (“NYAPP”).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I have testified before the Commission on a variety of matters, including allowed rate of return and capital structure for electric transmission activities within Regional Transmission Organizations (“RTOs”) and Independent System Operators (“ISOs”), natural gas pipeline rate proceedings, wholesale market design, and RTO cost allocation. A list of Commission proceedings in which I have participated is shown in Exhibit No. NYP-3.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide an independent analysis of a just and reasonable allowed return on equity (“ROE”) and the effect of that ROE on the overall weighted average cost of capital (“WACC”) for Niagara Mohawk Power Corporation d/b/a National Grid (“NMPC”), as related to that company’s membership and transmission operations in the New York Independent System Operator ("NYISO"). As my testimony shows, the current allowed return on equity of 11.5% is excessive, unjust, and unreasonable.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the next section of my testimony, I provide a summary of my findings. In Section III, I present my independent analysis of a just and reasonable allowed ROE for NMPC. In Section IV, I provide an analysis of NMPC's WACC using a just and reasonable ROE.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits and schedules:

Hearing Exhibit and Schedule Number	Description
Exhibit No. NYP-2	Curriculum Vitae of Jonathan A. Lesser
Exhibit No. NYP-3	List of Previous Commission Testimony
Exhibit No. NYP-4	Pages 245-247 from *Principles of Utility Corporate Finance*
Exhibit No. NYP-5	National Grid plc, "Results for the year ended 31 March 2012."
Exhibit No. NYP-6, Sch. 1	Utility Proxy Group Screening
Exhibit No. NYP-6, Sch. 2	"Sustainable" Earnings Growth Estimates
Exhibit No. NYP-6, Sch. 3	I/B/E/S Earnings Growth Estimates
Exhibit No. NYP-6, Sch. 4	Avg. Monthly High-Low Stock Prices and Dividend Yields
Exhibit No. NYP-6, Sch. 5	DCF Analysis Results
Exhibit No. NYP-7	Pages 188-190 from *Principles of Utility Corporate Finance*
Exhibit No. NYP-8, Sch. 1	Attachment 1, Schedule 8 from NMPC OATT Filing of June 14, 2012, as filed
Exhibit No. NYP-8, Sch. 2	Attachment 1, Schedule 8 from NMPC OATT Filing of June 14, 2012, as adjusted

II. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR ROE AND WACC ESTIMATES FOR NMPC.

A. My estimates are shown in Table 1.

Table 1: NMPC Weighted Average Cost of Capital and Components

Line No.	WACC Component	Rate	Pct. Of Capitalization	Weighted Cost
[1]	Long-term Debt	3.96%	49.53%	**1.96%**
[2]	Common Equity	9.49%	50.00%	**4.75%**
[3]	Preferred Equity	3.66%	0.47%	**0.02%**
[4]	**Total**		**100.00%**	**6.73%**

Sources:
1. Capital Structure, Cost of Debt, and Cost of Preferred Equity: "Informational Filing of Niagara Mohawk Power Corporation of the Annual Update to the Formula Transmission Service Charge Under the NYISO Open Access Transmission Tariff - Docket No. ER08-552-000, June 14, 2012,WP6.
2. Return on Common Equity: Table 4 (includes 50 bp adder).

As Table 1 shows, I have determined an overall weighted average cost of capital of 6.73%. This value is based on a recommended allowed return on equity of 9.49% (including a 50 basis point ("bp") adder for RTO or ISO membership, consistent with Commission policy);[1] (2) a capital structure of 49.53% long-term debt, 50.0% common equity, and 0.47% preferred equity, based on data reported in the NMPC 2011 FERC Form-1 Report and the formula rate on page 57 of Appendix H to the NYISO OATT on Schedule 8.[2]

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1 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, order on reh'g, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), order on reh'g, 119 FERC ¶ 61,062 (2007).

2 Available at: http://www.nyiso.com/public/webdocs/documents/tariffs/oatt/oatt_attachments/att_h.pdf, last accessed September 4, 2012.

Q. PLEASE SUMMARIZE THE IMPACT OF YOUR REVISED ROE AND WACC VALUES ON THE BEFORE-TAX RETURN FOR NMPC IN ITS JUNE 14, 2012 FILING.[3]

A. As a result of my revised estimate of allowed ROE and WACC, I find that the before-tax return value for NMPC should be reduced by $19,080,537, from the $136,652,963 before-tax return value shown in NMPC's June 14, 2012 filing to $117,572,426.

III. INDEPENDENT ANALYSIS TO DETERMINE ALLOWED ROE

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this section, I first provide a brief summary of the steps I took to perform my DCF analysis. Next, I discuss the economic and regulatory foundations that govern such analyses, and I discuss the business and financial risks faced by NMPC. Then, I provide a detailed discussion of each of the steps I performed, including selection of a proxy group of electric utilities based on the criteria previously established by the Commission, calculation of earnings growth rates, calculation of threshold DCF values and exclusion of individual companies if one or more of the DCF values fail to comport with the threshold values, and selection of a recommended ROE value based on the resulting zone of reasonableness.

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[3] *Informational Filing of Niagara Mohawk Power Corporation of the Annual Update to the Formula Transmission Service Charge Under the NYISO Open Access Transmission Tariff*, Docket No. ER08-552-000, June 14, 2012, Attachment 1, Schedule 8.

A. Summary of ROE Analysis

Q. PLEASE SUMMARIZE YOUR INDEPENDENT ROE ANALYSIS.

A. The starting point of any rate of return analysis is selection of an appropriate proxy group. I selected a proxy group of 16 electric utilities listed by the Value Line Investment Survey under its Electric Utility – West, Electric Utility – East, and Electric Utility – Central industry categories. I selected these 16 utilities based on the criteria established by FERC in *Southern California Edison*.[4] Specifically, I applied the following six criteria to select a proxy group:

1. Electric utilities that are covered by the Value Line Investment Survey ("Value Line");

2. Electric utilities that neither announced a merger or acquisition within the six-month analysis period nor were involved in an ongoing merger or acquisition during that period;

3. Electric utilities that have paid constant or increasing dividends for at least the past two years;

4. Electric utilities that are covered by at least two generally recognized utility industry analysts, and which have long-term (5-year) earnings growth forecasts reported by Institutional Brokers;

5. Electric utilities that have annual revenues of at least $1 billion (NMPC's revenues in 2011 were $3.9 billion); and

6. Electric utilities having an investment grade corporate credit rating within one "notch" of NMPC, which is currently rated "A^{-}" by Standard and Poor's (i.e. utilities having credit ratings between "BBB+" and "A").

B. Economic and Regulatory Foundations

Q. WHAT IS THE COST OF CAPITAL?

[4] *Southern Cal. Edison Co.*, 131 FERC ¶ 61,020, (2010) ("*Southern Cal. Edison I*"), P 51, reh'g denied, 137 FERC ¶ 61,016 (2011) ("*Southern Cal. Edison II*").

A. The cost of capital can be defined as the expected rate of return in capital markets on alternative investments of equivalent, or "comparable" risk. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The higher the risk, the higher is the cost of capital.

Q. WHY IS THE COST OF CAPITAL IMPORTANT IN RATE REGULATION?

A. It has become routine in U.S. rate regulation to accept the "cost of capital" as the right expected rate of return on utility investment. That practice is normally viewed as consistent with the U.S. Supreme Court's opinions in the *Bluefield*[5] and *Hope Natural Gas*[6] decisions, which suggest that a regulated utility's allowed returns by commensurate with other firms having similar business and financial risks.

From an economic perspective, rates are designed to provide investors a fair opportunity to earn the cost of capital at the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. Regulatory commissions normally try to prevent such outcomes unless there are offsetting benefits (*e.g.*, from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital does a disservice not just to investors but, importantly, to customers as well. In the long run, such a return denies the company the ability to attract capital, maintain its financial

5 *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of W. Va*, 262 U.S. 679 (1923).

6 *Federal Power Comm'n. v. Hope Natural Gas. Co*., 320 U.S. 591 (1944).

integrity, and expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

Q. CAN THE COST OF CAPITAL BE DIRECTLY OBSERVED?

A Although the cost of debt can be directly observed, the cost of equity cannot be. That is why different methodologies have been applied to estimate the cost of equity. Moreover, that is why using a proxy group of risk-comparable firms is a standard approach: a group of firms provides a more statistically robust set of information regarding the expected return needed to compensate investors fairly.

C. The Commission's DCF Methodology

Q. PLEASE DESCRIBE THE DCF METHODOLOGY.[7]

A. One of the basic tenets of corporate finance is that the price of a stock today equals the discounted present value of all future cash flows from holding that stock in perpetuity. Those cash flows are just the expected future dividend payments. In applying the DCF methodology, we determine the discount rate that equates the discounted present value of those future dividend payments to the stock's price today. Thus, the DCF methodology can be thought of as a stock valuation exercise in reverse.

The standard DCF formula is as follows:

$$P_0 = \frac{D_1}{(1+R_C)} + \frac{D_2}{(1+R_C)^2} + \frac{D_3}{(1+R_C)^3} + \cdots + \frac{D_t}{(1+R_C)^t} + \cdots \qquad (1)$$

[7] For a more detailed discussion, *see* L. Giacchino and J. Lesser, *Principles of Utility Corporate Finance*, (Vienna, VA: Public Utilities Reports, Inc. 2011) ("*PUCF*"), pp. 245-47 (attached hereto as Exhibit No. NYP-4).

where "P_0" is the price of the stock today, "D_t" is the expected dividend payment at the end of period t, and "R_C" is the cost of equity capital. If one assumes that the dividend payments will grow at a constant rate, "g," forever, then equation (1) can be shown to reduce to:

$$P_0 = \frac{D_1}{(R_C - g)} \qquad (2)$$

Equation (2) can then be solved for r. Thus, we have:

$$R_C = \frac{D_1}{P} + g = \frac{D_0\, x\,(1+g)}{P} + g\,, \qquad (3)$$

where "D_0" is the current dividend payment. Equation (3) is called the "Gordon growth model."

Q. ARE THERE ANY VARIANTS OF THE MODEL SHOWN IN EQUATION (3)?

A. Yes. For example, sometimes, it is assumed that the initial dividend payment in the model is received immediately. In that case, "D_1" in equation (3) is replaced with "D_0." There are also variants involving multiple growth rates, such as those representing short-term and long-term growth, which are called "multi-stage" DCF models.

Q. DOES THE COMMISSION USE THE DCF MODEL SHOWN IN EQUATION (3) FOR PURPOSES OF ESTIMATING THE ALLOWED RETURN ON EQUITY?

A. No. The Commission uses a slightly modified version, essentially splitting the difference regarding when the initial dividend is received. Thus, the Commission model is written:[8]

[8] Equation (4) is called a "one-stage" DCF model.

$$R_C = \frac{D_0\, x\,(1+g/2)}{P} + g = \frac{D_0}{P}\, x\,(1+g/2)+g \tag{4}$$

Q. IS THE DIVIDEND YIELD SIMPLY THE CURRENT DIVIDEND DIVIDED BY THE CURRENT STOCK PRICE?

A. No. The Commission uses an average of the past six months' stock prices and dividend payments. Specifically, the Commission determines "low" and "high" dividend yields in each of the previous six months, and then averages the results of each separately. Thus, the "low" dividend yield in a given month equals the most recent dividend payment divided by the highest closing stock price of the month, and the "high" dividend yield equals the most recent dividend payment divided by the lowest closing stock price of the month. The Commission then calculates the average "low" and high" dividend yields for the six-month period. These become the D_0/P values used in equation (4).

Q. HOW IS THE GROWTH RATE IN EQUATION (4) DETERMINED?

A. The Commission methodology uses two types of earnings growth forecasts to estimate the value of "*g.*" The first is the most current five-year forecast of earnings growth published by Institutional Brokers ("I/B/E/S") for each company in the proxy group. The second is what is known as the "sustainable" or "*br + sv*" earnings growth rate for each company.

Q. HOW ARE THESE TWO GROWTH RATES USED?

A. The two earnings growth rates are combined with the "low" and "high" dividend yields to determine overall "low" and "high" cost of equity estimates for each proxy group company.

Q. WHY ARE EARNINGS GROWTH FORECASTS USED WHEN THE GROWTH RATE IN EQUATION (3) REFERS TO THE DIVIDEND GROWTH RATE?

A. Earnings growth rates are used because, in the long run, dividend payments can only be derived from earnings. Thus, whereas earnings in a given quarter or year may be less than a company's dividend payment, a company cannot sustain dividend payments that are greater than its earnings in the long run. So, if a securities analyst forecasts a company's earnings to grow at, say, five percent per year, it is reasonable to assume that the company's dividend payments will grow at that same rate.

Q. DOES I/B/E/S PREPARE ITS OWN FORECASTS OF EARNINGS GROWTH?

A No. I/B/E/S compiles the five-year earnings growth forecasts prepared by independent securities analysts.

Q. HOW IS THE "SUSTAINABLE" EARNINGS GROWTH RATE ESTIMATED?

A The sustainable or "*br + sv*" growth rate is based on a premise that a company can grow only if it plows back some of its earnings for investment purposes. A company that pays all of its earnings out as dividends has nothing left to invest, and thus cannot continue to increase those dividend payments.

Estimating a "sustainable" growth rate requires several types of data. First, one must determine the company's retention ratio, which equals the fraction of earnings not paid out as dividends. For example, if the firm pays out 60 cents of every dollar in earnings as dividends, its retention ratio "*b*" is 1 – 0.60 = 0.40. Second, one estimates the company's actual and projected average year-end return on book equity "*r*" which equals earnings divided by the company's book value of equity. These year-end returns on average common equity are then adjusted for projected growth in the amount of common equity, as prescribed by the Commission in *Southern California Edison Company*, Opinion No. 445, 92 FERC ¶ 61,070 (2000).

Q. HOW IS THIS LATTER ADJUSTMENT CALCULATED?

A. This adjustment consists of: (1) calculating the proxy companies' overall common equity amounts as reported by Value Line for the five-year period 2011 and 2015-17 and calculating the average growth rate in common equity, "G_E," for that five-year period; and (2) adjusting the average year-end "r" values for each proxy group company by the quantity $\{2(1+G_E)/(2+G_E)\}$, again as set forth in Opinion No. 445.[9] The product of the retention ratio and the return, *i.e.*, $[b \cdot r]$ equals the amount available for future investment and, under the Commission's sustainable growth rate model, determines the future growth rate in earnings.

The sustainable growth rate also accounts for the effects of external financing from issuing new shares of stock, and the profitability of those new shares. The profitability of equity is based on the difference between its market value (MV) and book value (BV). Specifically, the profitability "v" is defined as

$$\frac{MV-BV}{BV}=\frac{MV}{BV}-1. \tag{5}$$

Thus, if "s" equals the rate of growth in new shares issued, then the contribution of those new shares to earnings growth equals $[s \cdot v]$. Therefore, the overall sustainable growth rate "g" equals $[b \cdot r] + [s \cdot v]$, hence the "$br + sv$" growth rate.

Q. WHAT DATA DID YOU USE TO CALCULATE THE SUSTAINABLE GROWTH RATES FOR YOUR PROXY GROUP?

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[9] *See* 92 FERC ¶ 61,070, ¶ 61,263, fn. 38.

A. I calculated sustainable growth rates using estimates taken from individual company reports published by Value Line. Specifically, I determined the average retention ratio and return on book equity based on data published in Value Line for the years 2011, 2012, and 2015-17. The use of the 2015-17 estimates provides a five-year forecast, consistent with the five-year earnings growth forecasts provided by I/B/E/S. Similarly, I calculated the projected growth rate in outstanding shares over that period and estimated equity profitability based on current share prices.

Q. WHAT TIME PERIOD DID YOU USE TO ESTIMATE LOW AND HIGH DIVIDEND YIELDS FOR YOUR COMPARABLE UTILITIES?

A. I used the six-month period between February 1, 2012 and July 31, 2012.

Q. WILL YOUR ANALYSIS REQUIRE UPDATING?

A. Yes. Although the February 1, 2012 through July 31, 2012 period I have used is current at this time, the Commission's policy is to update the cost of equity calculation at the time of the hearing in this proceeding. Thus, my analysis will require updating.

D. Selection of the Proxy Group of Companies

Q. HOW DID YOU SELECT YOUR PROXY GROUP OF COMPANIES FOR THE DCF ANALYSIS?

A. To select the proxy group, I used the criteria set forth in *Southern California Edison*.[10] Specifically, I used the following criteria:

1. Electric utilities that are covered by the Value Line;
2. Electric utilities that neither announced a merger or acquisition within the six-month analysis period nor were involved in an ongoing merger or acquisition during that period;

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[10] *Southern Cal. Edison I* at P 51.

3. Electric utilities that have paid constant or increasing dividends for at least the past two years;

4. Electric utilities that are covered by at least two generally recognized utility industry analysts, and which have long-term (5-year) earnings growth forecasts reported by I/B/E/S;

5. Electric utilities that have annual revenues of at least $1 billion (NMPC's revenues in 2011 were $3.9 billion, and the overall revenues of its corporate parent, National Grid USA were just over $12 billion);[11] and

6. Electric utilities having an investment grade corporate credit rating within one "notch" of NMPC, which is currently rated "A¯" by Standard and Poor's (i.e. utilities having credit ratings between "BBB+" and "A").

Q. HOW DID YOU EVALUATE THE ELECTRIC UTILITIES COVERED BY <u>VALUE LINE</u> FOR PURPOSES OF SELECTING YOUR PROXY GROUP?

A <u>Value Line</u> currently covers 49 electric utilities, including some utilities that have both electric and natural gas distribution operations. Of that total, I eliminated six utilities because of ongoing or recently completed merger/acquisition activity during the six-month analysis period. These utilities are: Central Vermont Public Service, whose merger with Green Mountain Power was finalized in June 2012; Duke Energy and Progress Energy, whose merger was finalized in June; and NStar and Northeast Utilities, whose merger was finalized in May 2012. I also eliminated CH Energy Group, whose purchase by Fortis was announced in February 2012.

Next, I eliminated two utilities lacking sufficient dividend history: El Paso Electric, which only restarted its dividend in June of 2011 after many years of no dividends, and Empire District Electric, which suspended its dividend in the third quarter

[11] Value is for the year ended March 31, 2012, based on an average exchange rate for the year of $1.60 per GBP. *See* National Grid plc, "Results for the year ended 31 March 2012," p.18 and p. 42 (note 12). (Attached as Exhibit NYP-5.)

of 2011. All of the other electric utilities have paid constant or increasing dividends for at least the last two years.

I then eliminated utilities with annual revenues in 2010 less than $1 billion.

Finally, I eliminated utilities having corporate credit ratings more than one notch above or below NMPC, *i.e.*, utilities with credit ratings of "A+" or above and utilities with credit ratings of BBB or below. This left a total of 16 utilities, as shown in Exhibit No. NYP-6, Schedule 1, and shown below in Table 2.

Table 2: NMPC DCF Analysis – Proxy Group Utilities

Alliant Energy	Pepco Holdings
CenterPoint Energy	SCANA Corp
Consol. Edison	Sempra Energy
Dominion Resources	Southern Co.
DTE Energy	TECO Energy
Integrys Energy	Vectren Corp.
NextEra	Wisconsin Energy
OGE Energy	Xcel Energy

E. DCF Estimates

Q. HOW DID YOU CALCULATE THE "BR + SV" OR "SUSTAINABLE" EARNINGS GROWTH ESTIMATES?

A. My "*br* + *sv*" calculations are set forth in Exhibit No. NYP-6, Schedule 2. I used <u>Value Line</u> data to estimate the average earnings per share, dividends per share, and book value per share values for each of the proxy companies to calculate the average internal growth (*i.e*., the "*b* · *r*") component. I then calculated the external growth (*i.e*., the "*s* · *v*") component by taking the average market value of each company's stock over the previous six months and dividing by the average book value. Finally, to calculate the external growth, I used the Value Line forecast of outstanding shares in the 2015/2017 time frame to determine the annual rate of share growth, as well as the forecast change in capital structure and total capitalization to reflect the growth adjustment factor referenced in Order No. 445.

Q. PLEASE DESCRIBE THE I/B/E/S EARNINGS GROWTH FORECAST VALUES YOU RELIED ON.

A. Because the six-month period I used to determine dividend yields was February 1, 2012 through July 31, 2012, I used the I/B/E/S earnings growth rates as forecast as of July 31, 2012, which are available on the website Yahoo!Finance for each proxy group utility.[12] This is reasonable because, in preparing an ROE estimate, the most current earnings growth estimates within the six-month period incorporate the most current information about the future performance of a stock. The I/B/E/S forecast growth rates are shown in Exhibit No. NYP-6, Schedule 3.

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12 These long-term earnings growth rates can also be obtained directly from Thomson-Reuters Datastream.

Q. HOW DID YOU ESTIMATE THE "LOW" AND "HIGH" STOCK PRICES FOR EACH MONTH, AND THE CORRESPONDING "HIGH" AND "LOW" DIVIDEND YIELDS?

A. My calculations are set forth in Exhibit No. NYP-6, Schedule 4. I relied on the adjusted daily closing stock prices as published by Yahoo!Finance and the quarterly dividend payment data published by Value Line for each of the proxy companies.

Q. WHAT IS AN ADJUSTED CLOSING PRICE?

A. An adjusted closing price reflects a stock's closing price on any given day of trading that has been adjusted to include any distributions and corporate actions, such as a stock split, that occurs at any time prior to the next day's opening. For example, suppose ABC Corporation pays a dividend of $0.50 per share on a date certain and that the unadjusted closing price of the stock is $20.00 per share. Then the adjusted closing price would just be $19.50, $20.00 less the $0.50 dividend. If ABC Corporation announces a 2-for-1 stock split (*i.e.*, each shareholder will receive two "new" shares for one existing share), then the adjusted stock price would be $20 divided by 2, or $10 per share.

Q. HOW DID YOU DETERMINE THE MINIMUM THRESHOLD DCF VALUE?

A. In *Southern California Edison I*, the Commission set the minimum threshold value at 100 basis points above the corresponding long-term utility corporate bond rate.[13] The reason for having such a threshold is that bond holders have a senior claim over a firm's assets than shareholders. Therefore, shareholders face higher financial risks than bondholders. This means that no shareholder will accept an expected return lower than the yield of the correspondingly rated long-term bond rates and, if fact, will expect a

[13] *Southern Cal. Edison I* at P 55.

higher return. The Commission therefore established a threshold value equal to 100 bp above the corresponding utility bond rate.

To calculate this threshold, I calculated the average of the monthly yields on BBB-rated, long-term utility bonds for the six-month period, February 1, 2012 through July 31, 2012, as reported by Moody's. That average yield on "A" rated bonds over this six-month period was 4.28% and the average yield on "BBB" rated bonds value was 5.01%, as shown in Table 3. Therefore, I established a minimum threshold DCF values 100 basis points above these averages, or 5.28% for "A" and "A^{-}" rated proxy group firms and 6.01% for "BBB+" rated proxy group firms.

Table 3: Moody's Average Long-Term Utility Bond Yields

Month	A-rated (Percent)	BBB-rated (Percent)
Feb-12	4.36	5.02
Mar-12	4.34	5.03
Apr-12	4.40	5.11
May-12	4.20	4.97
Jun-12	4.08	4.91
Jul-12	3.93	4.85
Average	**4.28**	**5.01**

Source: Moody's Economy.com

Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS?

A. The results of my DCF analysis for the proxy group are shown in Exhibit No. NYP-6, Schedule 5 and Table 4 below.

Table 4: FERC DCF Methodology Analysis Results

	Company	Symbol	6-Months Dividend Yield (Low)	6-Months Dividend Yield (High)	Earnings Growth (br+sv)	Earnings Growth (I/B/E/S)	Adjusted Dividend Yield (Low)	Adjusted Dividend Yield (High)	ROE (Low)	ROE (High)	Average ROE
			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1	Alliant Energy	LNT	3.88%	4.06%	4.26%	6.30%	3.96%	4.19%	8.22%	10.49%	9.35%
2	CenterPoint Energy	CNP	3.95%	4.13%	4.37%	4.90%	4.03%	4.23%	8.40%	9.13%	8.77%
3	Consol. Edison	ED	3.96%	4.12%	3.36%	3.02%	4.02%	4.19%	7.04%	7.55%	7.30%
4	Dominion Resources	D	3.84%	3.97%	5.87%	5.00%	3.93%	4.08%	8.93%	9.95%	9.44%
5	DTE Energy	DTE	4.09%	4.28%	3.66%	4.59%	4.16%	4.38%	7.82%	8.97%	8.39%
6	Integrys Energy	TEG	4.91%	5.16%	1.43%	5.00%	4.94%	5.29%	6.38%	10.29%	8.33%
7	NextEra	NEE	3.49%	3.63%	6.83%	5.23%	3.58%	3.75%	8.81%	10.58%	9.70%
8	OGE Energy	OGE	2.84%	2.98%	7.65%	5.00%	2.91%	3.10%	7.91%	10.75%	9.33%
9	Pepco Holdings	POM	5.58%	5.78%	1.06%	4.75%	5.61%	5.92%	6.67%	10.67%	8.67%
10	SCANA Corp	SCG	4.17%	4.32%	5.38%	6.13%	4.28%	4.45%	9.66%	10.58%	10.12%
11	Sempra Energy	SRE	3.02%	3.17%	5.65%	7.00%	3.11%	3.28%	8.76%	10.28%	9.52%
12	Southern Co.	SO	4.13%	4.27%	5.12%	5.38%	4.24%	4.38%	9.36%	9.76%	9.56%
13	TECO Energy	TE	4.86%	5.07%	4.59%	2.66%	4.92%	5.19%	7.58%	9.78%	8.68%
14	Vectren Corp.	VVC	4.72%	4.89%	3.59%	5.00%	4.81%	5.01%	8.40%	10.01%	9.21%
15	Wisconsin Energy	WEC	2.93%	3.06%	5.19%	6.05%	3.01%	3.15%	8.20%	9.20%	8.70%
16	Xcel Energy	XEL	3.75%	3.88%	4.54%	5.08%	3.84%	3.98%	8.37%	9.06%	8.72%

Minimum	6.38%		Min of Avg	7.30%
Maximum	10.75%		Max of Avg	10.12%
Median	9.01%	===>>>>>	Median of Avg:	8.99%
Midpoint	8.56%		Midpoint	8.71%

Moody's long-term BBB utility bond yield, 6-mos avg., ending July 2012	4.98%
Moody's long-term A utility bond yield, 6-mos avg., ending July 2012	4.22%
Exclude BBB-rated firms with values less than:	5.98%
Exclude A-rated firms with values less than:	5.22%
Number of Excluded Firms	0

Notes:

[1] Equals annual dividend divided by 6-months high stock price ending 7/31/2012

[2] Equals annual dividend divided by 6-months low stock price ending 7/31/2012

[3] Source: Value Line Investment Survey (Calculation is summarized in "Earnings Growth (br+sv)" Tab)

[4] Source: I/B/E/S Thomson Reuters, July 31, 2012 Forecasts

[5] Equals [2]*(1+0.5*MIN[3],[4]))

[6] Equals [2]*(1+0.5*MAX([3],[4]))

[7] Equals MIN([3],[4]) plus [5]

[8] Equals MAX([3],[4]) plus [6]

[8] Equals ([8] + [9]) / 2.

All of the DCF estimates for the proxy group companies are above the threshold DCF value of 6.01% for "BBB" rated firms (and, hence, above the threshold DCF value for "A" rated firms). As shown, the resulting zone of reasonableness is between 6.38% and 10.75%, and the median of the average of the "low" and "high" values of the proxy group companies in column [9] is 8.99%.

Q. YOU ALSO SHOW A "MEDIAN" VALUE OF 9.01% ON THE LEFT-HAND SIDE OF TABLE 4. CAN YOU EXPLAIN WHY THAT DIFFERS FROM THE 8.99% MEDIAN OF THE AVERAGE VALUES?

A. Yes. My understanding is that, to establish a median ROE, the Commission prefers to first determine the average of each remaining proxy company's "low" and "high" DCF values and then select the median of the resulting range. Thus, the 8.99% value is the median value of the values shown in column [9] of Table 4.

The 9.01% value shown on the left-hand side of Table 4 and Exhibit No. NYP-6, Schedule 5, is the median of the larger sample of 32 values that includes the "low" and "high" values for each company. It is not surprising that the median of the larger sample is slightly different from the median of the average values.

Q. DO YOU HAVE AN OPINION AS TO WHICH MEDIAN VALUE IS MORE STATISTICALLY VALID?

A. Yes. In my opinion, the median of the entire sample, before averaging the "low" and "high" values, has greater statistical validity. The larger sample reflects the same overall zone of reasonableness but provides twice the number of sample values from which the median is taken. Thus, even though the average values of both groups are necessarily the same, the standard deviation of the 20-value average is much smaller than the standard deviation of the 10-value average.[14] However, the 2 bp difference in the values, 8.99% versus 9.01% is *de minimus*.

Q. DOES YOUR RECOMMENDED ROE VALUE OF 9.49%, AS SHOWN PREVIOUSLY IN TABLE 1, ALSO INCLUDE THE 50 BP ADDER FOR MEMBERSHIP IN AN ISO OR RTO?

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[14] The standard deviation of the <u>average</u> of a distribution equals the standard deviation of the entire sample divided by the square root of the number of observations. Thus, if the standard deviation of a sample of N observations is σ, then the standard deviation of the average equals $\sigma / \sqrt{N}$.

A Yes. I have taken the 8.99% median value shown in Table 4 and added 50 bp, resulting in my overall recommended ROE value of 9.49%, as prescribed by Commission policy in Order No. 679.[15]

F. Adjustment for Business and Financial Risk

Q. DOES THE COMMISSION EVER DEVIATE FROM ESTABLISHING THE ROE AT THE MEDIAN OF THE ZONE OF REASONABLESS?

A. Yes. My understanding is that the Commission sets the ROE at the median of the zone of reasonableness unless there is specific evidence that the subject company has a business and financial risk profile that differs significantly from the "average" risk of the firms in the proxy group.[16]

Q. WHAT IS MEANT BY THE TERMS "BUSINESS RISK" AND "FINANCIAL RISK"?

A. Business risk is typically defined as "the risk that a business will experience a period of poor earnings and, as a consequence, be unable to meet its financial obligations, such as the interest payments on its outstanding debt."[17] Financial risk reflects a firm's ability to service its outstanding debt and maintain specific financial metrics associated with that debt, such as interest coverage ratios.

Q. DO REGULATED UTILITIES FACE ANY OTHER TYPE OF RISK THAT CAN AFFECT THE REQUIRED EQUITY RETURNS TO INVESTORS?

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[15] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, order on reh'g, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), order on reh'g, 119 FERC ¶ 61,062 (2007).

[16] *See, e.g., Golden Spread Elec. Coop., Inc.. v. SWECI Pub. Serv. Co.*, 123 FERC ¶ 61,047 (2008), Opinion No. 501 at P 64.

[17] *PUCF*, pp. 188-90 (attached hereto as Exhibit No. NYP-7).

A. Yes. Regulatory risk is a third type of risk that affects investor expectations. As I state in *Principles of Utility Corporate Finance* ("PUCF"), "Regulated firms rely on consistency from regulators and assurance that existing regulations will be applied in a fair and reasonable way."[18] There is no evidence that NMPC faces any unusual regulatory risk, given that the National Grid plc report, "Results for the year ended 31 March 2012," which was previously attached as Exhibit NYP-5, notes that, "Overall we have seen another year of measured progress developing our regulatory arrangements. Taken together with the benefit of our efficiency programmes, this progress underpins our confidence that we will be able to deliver improved returns from our US operations."[19] The report further states that, "The restructuring of our US business is now complete and is delivering operational and financial benefits to underpin our progress on further improving US returns."[20] Again, therefore, there is nothing noted about any unusual regulatory risk faced by NMPC.

Q. DOES THE NATIONAL GRID PLC REPORT DISCUSS ANY EXTRAORDINARY BUSINESS OR FINANCIAL RISKS RELATED TO RATE REGULATION OF ITS U.S. SUBSIDIARIES?

A. No. In that same report, National Grid plc states that it is improving the overall efficiency of its U.S. operations and projects higher returns. There is no discussion of any extraordinary business or financial risks that would merit setting the allowed ROE for NMPC other than at the median value of the proxy group.

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[18] *Id*., p. 190.

[19] Exhibit NYP-4, Schedule 2, p. 5.

[20] *Id*., p. 9.

IV. DETERMINATION ON CAPITAL STRUCTURE AND OVERALL WACC FOR NMPC

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A In this section of my testimony, I demonstrate the effect of using an ROE of 9.49% on NMPC's overall WACC and the required before-tax investment return. I relied on the tariff formula rate for calculating the cost of capital, as set forth on page 57 of Attachment H to the NYISO OATT on Schedule 8.[21] A copy of Schedule 8, as filed on June 14, 2012, is attached as Exhibit No. NYP-8, Schedule 1. As shown on line 21, the formula-based WACC is 7.73%. As shown on line 64, the resulting value for the before-tax return ("investment return plus taxes") is $136,652,963.

Q. HOW DOES THE FORMULA RATE SPECIFY CAPITAL STRUCTURE?

A. Schedule 8 uses a specific formula for capital structure that limits the percentage of common equity to no more than 50% of total capitalization. If the actual common equity capitalization is greater than 50%, then under the formula rate it is reduced to 50% and the percentage reduction is then added to the long-term debt capitalization percentage. For example, if the common equity percentage were 55% of total capitalization, for ratemaking purposes it would be reduced by 5% to 50% and the long-term debt percentage would be similarly increased by 5%. Because the actual amount of common equity shown on line 19 of Schedule 8 is $3,813,721,822, which is 61.33% of the total capitalization of $6,218,289,604 shown on line 21, the equity capitalization percentage is reduced by 11.33% to the 50% maximum and the long-term debt

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[21] *Informational Filing of Niagara Mohawk Power Corporation of the Annual Update to the Formula Transmission Service Charge Under the NYISO Open Access Transmission Tariff*, Docket No. ER08-552-000, June 14, 2012, Attachment 1, Schedule 8.

percentage is increased 11.33% to 49.53%, as shown on line 17 of Schedule 8. (The preferred equity percentage is not adjusted from its actual value of 0.47% under the formula.) In calculating the revised WACC value for NMPC, I have used these capitalization percentages for common equity, long-term debt, and preferred equity.

Q. WHAT IS THE RESULTING WACC FOR NMPC, USING YOUR 9.49% ROE AND THE FORMULA-RATE CAPITALIZATION PERCENTAGES AND RATES?

A. As shown previously in Table 1, I derive an overall WACC of 6.73%.

Q. HAVE YOU ESTIMATED THE IMPACT OF THE 6.73% WACC YOU CALCULATE ON THE BEFORE-TAX INVESTMENT RETURN SHOWN ON LINE 64 OF SCHEDULE 8 THAT WAS FILED ON JUNE 14, 2012?

A Yes. The revised estimate is shown on line 64 of Exhibit No. NYP-8, Schedule 2. As can be seen, using the lower ROE results in a revised before-tax return of $117,572,426. This represents a reduction of $19,080,537 from the $136,652,963 before-tax return shown in the June 14, 2012 filing.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

Exhibit No. NYP-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Company (d/b/a) National Grid USA	))))	**Docket No. ER12-___-000**

VERIFICATION

I, Jonathan A. Lesser, declare under penalty of perjury that the foregoing testimony is true and correct.

Executed this 11th day of SEPTEMBER, 2012.

Jonathan A. Lesser

Jonathan A. Lesser, Ph.D.

President

SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has over 25 years of experience working for regulated utilities, governments, and as an economic consultant. He has extensive experience in valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

He has analyzed economic and regulatory issues affecting the energy industry, including cost-benefit analysis of transmission, generation, and distribution investment, gas and electric utility structure and operations, generating asset valuation under uncertainty, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, cost of capital, depreciation, risk management, incentive regulation, economic impact studies of energy infrastructure development, and general regulatory policy.

Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous U.S. states; before the Federal Energy Regulatory Commission (FERC); before international regulators in Latin America and the Caribbean; in commercial litigation cases; and before legislative committees in Connecticut, Maryland, New Jersey, Ohio, Texas, Vermont, and Washington State. He has also served as an independent arbiter in disputes involving regulatory treatment of utilities and valuation of energy generation assets.

Dr. Lesser is the author of numerous academic and trade press articles. He is also the coauthor of *Environmental Economics and Policy*, published in 1997 by Addison Wesley Longman, *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., and *Principles of Utility Corporate Finance*, published in 2011 by Public Utilities Reports, Inc. Dr. Lesser is also a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

AREAS OF EXPERTISE

- State, federal, and international rate regulation – cost of capital, depreciation, cost of service, cost allocation, rate design, incentive regulation, and regulatory framework design
- Commercial damages estimation and litigation
- Cost-benefit analysis
- Regulatory policy and market design
- Economic impact analysis and input-output studies
- Environmental compliance and litigation
- Market power analysis
- Load forecasting and energy market modeling
- Energy asset valuation and due diligence

SELECTED EXPERT TESTIMONY AND REPORTS

Caribbean Utilities Company, Ltd.

♦ Rebuttal report on weighted average cost of capital methodology and recommendations for Caribbean Utilities Company, Ltd.

Long Island Power Authority

♦ Estimation of rate of return for renegotiation of long-term power purchase agreement under FERC regulation.

Utah Industrial Energy Users Coalition

♦ Proceeding before the Utah Public Service Commission (Case No. U-11035-200)

Subject: Appropriate methodology for embedded cost allocation for Rocky Mountain Power.

FirstEnergy Solutions Corp.

♦ Proceeding before the Michigan Public Service Commission (Case No. U-17032)

Subject: Indiana & Michigan Power Co. proposed capacity charges for customers taking retail electric service.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO)

  Subject: Revised AEP Ohio energy security plan, benefits of retail market competition.

- Proceeding before the Ohio Public Utilities Commission (Case No. 10-2929-EL-UNC)

  Subject: Appropriate price for commercial retail electric suppliers to be charged by AEP Ohio for installed capacity under the PJM Fixed Resource Requirement tariff option.

Southwestern Electric Cooperative

- FERC proceeding regarding wholesale distribution rate application of Ameren Illinois (*Re: Midwestern ISO and Ameren Illinois*, Docket No. ER11-2777-002, et al.)

Subject: Allowed rate of return and capital structure

Exelon Corporation

- Proceeding before the New Jersey Board of Public Utilities (Docket No. EO-11050309)

Subject: PJM Capacity Market, Capacity Procurement, and Transmission Planning

Industrial Energy Users of Ohio

- Proceeding before the Ohio Public Utilities Commission (Case No. 08-917-EL-SSO)

  Subject: Determination of cost associated with "provider-of-last-resort" (POLR) service and AEP Ohio's use of option pricing models.

Southwest Gas Corporation

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP10-1398-000)

Subject: Development of risk-sharing methodology for unsubscribed and discount capacity costs.

Portland Natural Gas Shippers

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP10-729-000)

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP08-306-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Independent Power Producers of New York

- FERC proceeding (New York Independent System Operator, Inc., Docket No. ER11-2224-000)

  Subject: Reasonableness of the proposed installed capacity demand curves and cost of new entry values proposed by the New York Independent System Operator.

Maryland Public Service Commission

- Merger application of FirstEnergy Corporation and Allegheny Energy, Inc. (I/M/O FirstEnergy Corp and Allegheny Energy, Inc., Case No. 9233)

  Subject: Proposed merger between FirstEnergy Corporation and Allegheny Energy. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power and merger synergies.

Alliance to Protect Nantucket Sound

- Proceeding before the Massachusetts Department of Public Utilities (Case No. D.P.U. 10-54)

  Subject: Approval of Proposed Long-Term Contracts for Renewable Energy With Cape Wind Associates, LLC.

Brookfield Energy Marketing, LLC

- FERC proceeding (*New England Power Generators Association, et al. v. ISO New England, Inc.,* Docket Nos. ER10-787-000, ER10-50-000, and EL10-57-000 (consolidated)).

  Subject: Proposed forward capacity market payments for imported capacity into ISO-NE.

Public Service Company of New Mexico

- Proceeding before the New Mexico Public Regulation Commission (Case No. 10-00086-UT)

  Subject: Load forecast for future test year, residential price elasticity study.

M-S-R Public Power Agency

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER09-187-000 and ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

Financial Marketers

- FERC proceeding (*Black Oak Energy, LLC v PJM Interconnection, L.L.C.*, Docket No. EL08-014-002)

  Subject: Allocation of surplus transmission line losses under the PJM tariff.

Southwest Gas Corporation and Salt River Project

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP08-426-000)

Subject: Analysis of proposed capital structure and recommended capital structure adjustments

New York Regional Interconnect, Inc.

- Proceeding before the New York Public Service Commission (Case No. 06-T-0650)

  Subject: Analysis of economic and public policy benefits of a proposed high-voltage transmission line.

Occidental Chemical Corporation

- FERC Proceeding (*Westar Energy, Inc.* ER07-1344-000)

  Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

- FERC Proceeding (*Ameren Services Company v. Midwest Independent System Operator, Inc.,* Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated)

  Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

- Proceeding before the Public Utility Commission of Texas (*Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line with Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, and Orange Counties*, Docket No. 34611, SOAH Docket No. 473-08-3341)

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

- Proceeding before the Oklahoma Corporation Commission (*Request of Public Service Company of Oklahoma for the Oklahoma Corporation Commission to Retain an Independent Evaluator,* Cause No. PUD 200700418)

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

- FERC Proceeding (*ISO New England Inc. and New England Power Pool,* Docket No. ER08-1209-000)

  Subject: Compensation of Rejected De-list Bids Under ISO-NE's Forward Capacity Market Design

Dynegy Power Marketing, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages accruing to Dynegy arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in NYISO during the summer of 2002.

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited*.

  Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain*

Transmission Assets to the Midwest Independent Transmission System Operator, Inc., Case No. EO-2008-0046.

Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

  Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc*., Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate rate of return for regulated milk processors in the Commonwealth of Puerto Rico.

DPL Inc.

- Proceeding before the Ohio Board of Tax Appeals (*DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437)

  Subject: Economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

  Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of benefits of restructuring since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate rate of return for the natural gas pipeline industry.

BP Canada Marketing Corp.

- FERC proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER09-1521-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER08-1318-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER07-1213-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER06-1325-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc*., Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
  - Concurrent proceedings: *Re: Green Mountain Power Corp*., Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
  - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy to analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.
  - *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC proceeding regarding the rate application of Northern Natural Gas Company (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and

development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

- o *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC rate proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.
  - *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.
  - *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
  - *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

COMMERCIAL LITIGATION EXPERIENCE

- *Vacqueria Tres Monjitas and Suiza Dairy, Inc. v. Jose O. Laboy, in his Official capacity, as the Secretary of the Department of Agriculture for the Commonwealth of Puerto Rico, and Juan R. Pedro-Gordian, in his official capacity, as Administrator of the Office of the Milk Industry Regulatory Administration for the Commonwealth of Puerto Rico.* U.S. District Court, District of Puerto Rico, Civil Case No. 04-1840. Determined the appropriate "country risk" premium for the fresh milk dairy industry in the Commonwealth of Puerto Rico.

- *Lorali, Ltd., et al. v. Sempra Energy Solutions, LLC, et al*. Damages associated with abrogation of retail electric supply contract.
- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.
- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.
- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.
- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.
- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.
- *Nat'l. Association of Electric Manufacturers v. Sorrell.* U.S. District Court for the District of Vermont. Expert report and testimony on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

***TransCanada Hydro Northeast, Inc. v. Town of Littleton, New Hampshire*, (CPR File No. G-09-24).**

Subject: dispute regarding valuation for property tax purposes of a hydroelectric facility located on the Connecticut River.

Served as neutral on a three-person arbitration panel.

***Belize Electricity Limited v. Belize Public Utilities Commission* (Claim No. 512 of 2008)**.

Subject: Proceeding before the Supreme Court of Belize alleging that the Final Decision by the Belize Public Utilities Commission setting electric rates and tariffs for the 2008-2009 period were unreasonable and non-compensatory.

Prepared independent report on behalf of the Belize Supreme Court for arbitration of the dispute.

SELECTED BUSINESS CONSULTING EXPERIENCE

- For the Manhattan Institute, prepared a comprehensive report on the economic impacts of early shutdown of the Indian Point Nuclear Facility.
- For Energy Choice Now, prepared a report on economic benefits of electric competition in Michigan.
- For the COMPETE Coalition, prepared a report on how electric competition creates economic growth.
- For an industry group, developed econometric models of the impacts of shale gas production on U.S. natural gas and electric prices.
- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.
- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.
- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
  - Sector Issues: Basic Techniques–Energy
  - Sector Issues in Rate Design: Energy
  - Sector Issues in Rate Design: Energy–Case Studies
  - Transmission Pricing Issues

- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over

future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.

- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

EDUCATION

- PhD, Economics, University of Washington
- MA, Economics, University of Washington
- BSc, Mathematics and Economics (with honors), University of New Mexico

EMPLOYMENT HISTORY

- 2009–Present: Continental Economics, Inc., President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.
- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1996–1998: Adjunct Lecturer, School of Business, University of Vermont.
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.
- 1990–1993: Adjunct Lecturer, Dept. of Business and Economics, Saint Martin's College.
- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, Load Forecasting Analyst.

PROFESSIONAL ACTIVITIES

- Reviewer, *Energy*
- Reviewer, *The Energy Journal*
- Reviewer*, Energy Policy*
- Reviewer, *Journal of Regulatory Economics*

PROFESSIONAL ASSOCIATIONS

- Energy Bar Association
- International Association for Energy Economics
- Society for Benefit-Cost Analysis

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.
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- Lesser, J., and J. Weber. "The 65 M.P.H. Speed Limit and the Demand for Gasoline: A Case Study for the State of Washington." *Energy Systems and Policy* 13 (July 1989): 191–203.
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- Lesser, J., and L.R. Giacchino. *Fundamentals of Energy Regulation*, Vienna, VA: Public Utilities Reports, 2007.
- Lesser, J., and R. Zerbe. "A Practitioner's Guide to Benefit-Cost Analysis." In *Handbook of Public Finance*, edited by F. Thompson, 221–68. New York: Rowan and Allenheld, 1998.
- Lesser, J., D. Dodds, and R. Zerbe. *Environmental Economics and Policy*, Reading: MA: Addison Wesley Longman, 1997.

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- Lesser, J. "How Will EPA's Newest Regulations Affect Electric Markets?" *Natural Gas and Electricity* (June 2012): 30-32.
- Lesser, J. "Pipeline Petulance," *Natural Gas and Electricity* (March 2012): 27-29.

- Lesser, J. "Global Warming, Climate Change, er Climate Volatility: 2012 and Beyond," *Natural Gas and Electricity* (January 2012): 22-24.
- Lesser, J., "Sunburnt: Solyndra, Subsidies, and the Green Jobs Debacle," *Natural Gas & Electricity* (November 2011):30-32..
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- Lesser, J., "Déjà vu All Over Again: The Grass was not Greener Under Utility Regulation." *The Electricity Journal* 20 (December 2007): 35–39.

- Lesser, J., "Blowin' in the Wind: Renewable Energy Mandates, Electric Rates, and Environmental Quality." *Natural Gas & Electricity* (October 2007): 26-28.

- Lesser, J., "No Leg to Stand On." *Natural Gas & Electricity* (August 2007): 28–31.

- Lesser, J., "Goldilocks Chills Out." *Natural Gas & Electricity* (July 2007): 26–28.

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- Lesser, J., and G. Israilevich, "The Capacity Market Enigma." *Public Utilities Fortnightly* 143 (December 2005): 38-42.

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- Lesser, J., "Is it How Much or Who Pays? A Response to Rothkopf." *The Electricity Journal* 10 (December 1997): 17–22.
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- Lesser, J., "Economic Analysis of Distributed Resources: An Introduction." *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
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- Lesser, J., "Long-Term Utility Planning Under Uncertainty: A New Approach." Paper presented for the Electric Power Research Institute: *Innovations in Pricing and Planning*, May 1990.
- Lesser, J., "Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies." *Public Utilities Fortnightly* (June 1990).
- Lesser, J., "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.

Other Publications

- Lesser, J., and R. Bryce, "The High Cost of Closing Indian Point," *New York Post*, August 8, 2012.
- Lesser, J., "Cap-and-Trade for Gasoline?" *Wall Street Journal*, June 14, 2008, A14.
- Lesser, J., "Overblown Promises: The Hidden Costs of Symbolic Environmentalism." *Livin' Vermont* (January/February 2005): 7, 27.

Selected speaking engagements

- "EPA Regulation of Generator Emissions – Key Market Issues," Energy Bar Association, Annual Meeting, April 28, 2012.

- "Competitive Energy Markets: How are they Working?" Constellation Executive Energy Forum, November 2, 2011.
- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
- "Financing the Smart Grid," Energy Bar Association Seminar, Washington, DC, December 4, 2009.
- "Renewable Power: At the Crossroads of Economics and Policy," Presentation to the Utilities State Government Organization, Newport, Rhode Island, July 13, 2009.
- "The Stimulus Act and Laws they Didn't Teach You in Law School," presentation to the 27th National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Rate Recovery for Capital Intensive Generation: Rate Base and Construction Work in Progress," Law Seminars International, Las Vegas, NV, February 5, 2009.
- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.
- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.
- "Energy and the Environment." Vermont Journal of Environmental Law, South Royalton, VT, March 10, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

JONATHAN A. LESSER, PHD

LIST OF FERC TESTIMONY AND PROCEEDINGS

- Docket No. ER11-2777-002, et al. Southwestern Electric Cooperative, *Midwestern Independent System Operator*, *Inc. and Ameren Illinois Company*.
- Docket No. RP10-1398, Southwest Gas Corporation, *El Paso Natural Gas Company*.
- Docket No. RP10-729-000, Shippers' Group, *Portland Natural Gas Transmission System*.
- Docket No. ER11-2224-000, Independent Power Producers of New York, *New York Independent System Operator, Inc*.
- Docket No. ER10-2026-000, Transmission Agency of Northern California. *Re: Pacific Gas & Electric Company*.
- Docket No. ER10-160-000, M-S-R Public Power Agency, *Southern California Edison Co*.
- Docket Nos. ER09-187-000 and ER10-160-000, M-S-R Public Power Agency, *Southern California Edison Co*.
- Docket No. EL08-014-002. Black Oak Energy, et al. *Black Oak Energy, LLC v. PJM Interconnection, L.L.C*.
- Docket No. RP08-426-000. Southwest Gas Corporation and Salt River Project. *El Paso Natural Gas Company*.
- Docket No. ER08-306-000. Shippers' Group. *Portland Natural Gas Transmission System*.
- Docket No. ER07-1344-000. Occidental Chemical Corp. *Westar Energy*, *Inc*.
- Docket No. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated). EPIC Merchant Energy, LLC, et al. *Ameren Services Company v. Midwest Independent System Operator, Inc.*
- Docket No. ER08-1209-000. The NRG Companies. *ISO New England Inc. and New England Power Pool.*
- Docket No. EL08-67-000. Constellation Energy Group. *Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC.*

- Docket No. ER08-283-000. Independent Power Producers of New York. *New York Independent System Operator, Inc.*
- Docket No. ER07-1182-000. Electric Power Supply Association. *Midwest Independent Transmission System Operator, Inc.*
- Docket No. RP06-407-000. BP Canada Energy Marketing Corp. *Re: Gas Transmission Northwest.*
- Docket No. RP06-072-000. BP Canada Energy Marketing Corp. *Re: Northern Border Pipeline.*
- Docket No. ER05-1284-000. Transmission Agency of Northern California. *Re: Pacific Gas & Electric Company.*
- Docket Nos. ER03-409-000, ER03-666-000. Transmission Agency of Northern California. *Re: Pacific Gas & Electric Company*.
- Docket No. RP05-163-000. Sierra Pacific Power Corp. *Re: Paiute Pipeline Company*.
- Docket No. ER03-563-030. Duke Energy North America, LLC. *Re: Devon Power, LLC, et al*.
- Docket No. EL05-17-000. Dynegy Power Marketing, LLC. *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*
- Docket No. EL05-17-000. KeySpan-Ravenswood, LLC. *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*
- Docket No. EL03-236-002. Electric Power Supply Association. *Re: PJM Interconnection, Inc*.
- Docket No. RP03-398-000. Pipeline Shippers. *Re: Northern Natural Gas Company*.
- Docket No. CP01-423-000., Dynegy. *Re: Dynegy LNG Production Terminal, LP*.
- Docket No. RP99-485-000. Missouri Gas Energy Co., *Re: Kansas Pipeline Corporation*.
- Technical hearings on wholesale electric capacity market design (2008).

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CHAPTER 12
DISCOUNTED CASH FLOW MODELS TO ESTIMATE RETURN ON EQUITY

12.1 Introduction

Although discounted cash flow (DCF) models are used extensively in finance, such as valuing assets, in cost-benefit studies, and so forth, are focus in this chapter is how DCF models are applied to estimate regulated firms' return on equity (ROE). In this sense, DCF models used to estimate ROE have a much narrower focus: we are determining the discount rate that equates the price of a firm's stock today with the present value of all expected future cash flows, as we discussed in Chapter 4. Thus, it can be thought of as a stock valuation exercise in reverse.

When regulators apply a discounted cash flow (DCF) model—and we discuss are a number of variants that in this chapter—to estimate ROE they must address a number of issues. First, there is ever-present issue of selecting an appropriate proxy group of firms with which to compare the utility, as we discussed in Chapter 9.[1] Once that is accomplished, however, regulators must estimate the cash flows to use in a DCF model, specifically the future dividend payments that make up those cash flows and their timing. That, in turn, often involves regulators evaluating estimates of both short-term growth rates and long-term rates. Fourth, regulators must deal with the actual costs incurred to issue new stock. The ways regulators address these different issues is the subject of this chapter.

12.2 The Dividend Growth Model

In Chapter 4, we discussed how a firm's stock price today equals the expected value of all future cash flows associated with that stock, including all future dividend payments and appreciation in the stock's price.[2] Recall that we wrote this as follows:

$$P_0 = \frac{D_1}{(1+r)} + \frac{D_2}{(1+r)^2} + \cdots + \frac{D_T}{(1+r)^T} + \frac{P_T}{(1+r)^T}, \qquad (12\text{-}1)$$

where: P_0 is the price of the stock today;

1 Recall that we select a proxy group of firms having similar business and financial risks because directly estimating the ROE of the regulated utility under study results in a circularity problem: investors' expectations are determined, in part, by what return they believe regulators will allow, which influences stock prices, earnings growth, and so forth. Thus, if regulators directly estimate the utility's ROE, they are really estimating what they will allow.

2 The theory underlying the DCF holds for any stock. However, historically the use of the DCF to estimate utilities' cost of equity was ideally suited because utilities paid steady dividends.

P_T is the price of the stock after T periods;

D_t are the dividend payments (assumed to be periodic);

P_t is the price of the stock after T time periods; and

r is the discount rate.

The simplest form of DCF model assumes that dividends will grow at the same annual rate forever, and that shareholders do not sell their shares after T periods. This form of DCF model is also called the *Dividend Growth Model* or *Gordon Growth Model*, since the cash flows from a stock held in perpetuity will just be the future dividend payments.[3] This "perpetual" DCF model is the most commonly used form of the DCF models. It assumes that dividends are paid in discrete time periods (annually, quarterly, etc.) and will continue to be paid in the same manner forever.

If we assume that the stock is held forever, then there is no revenue received in the future from the sale of the stock, and the stock price today will solely reflect the stream of expected annual dividend payments. If we assume that the dividend payments will grow at a constant rate, g%, over time and that the stock is held forever, we can rewrite equation (12-1) as

$$P_0 = \frac{D_0 \cdot (1+g)}{(1+r)} + \frac{D_0 \cdot (1+g)^2}{(1+r)^2} + \cdots + \frac{D_0 \cdot (1+g)^T}{(1+r)^T} + \cdots = \sum_{t=1}^{\infty} \frac{D_0 \cdot (1+g)^t}{(1+r)^t}. \quad (12\text{-}2)$$

Next, we simplify equation (12-2) as follows:

$$P_0 = \frac{D_0 \cdot (1+g)}{(1+r)} \left[1 + \frac{(1+g)}{(1+r)} + \frac{(1+g)^2}{(1+r)^2} + \cdots + \frac{(1+g)^{T-1}}{(1+r)^{T-1}} + \cdots \right]. \quad (12\text{-}3)$$

The term in brackets is an infinite series, which by applying the formula for a perpetuity we derived in Chapter 3 can be written as:[4]

$$\left[1 + \frac{(1+g)}{(1+r)} + \frac{(1+g)^2}{(1+r)^2} + \cdots + \frac{(1+g)^{T-1}}{(1+r)^{T-1}} + \cdots \right] = \frac{1}{[1-(1+g)/(1+r)]} = \frac{1+r}{r-g}. \quad (12\text{-}4)$$

Substituting equation (12-4) into equation (12-3), we have

$$P_0 = \frac{D_0 \cdot (1+g)}{(1+r)} \cdot \frac{(1+r)}{(r-g)} = \frac{D_0 \cdot (1+g)}{r-g} = \frac{D_1}{r-g}. \quad (12\text{-}5)$$

Equation (12-5) is quite important. It says that the price of the stock today equals next year's expected dividend payment divided by the difference between the discount rate and the forecast growth rate. Using this equation, we can also solve for the price in future years. In general,

3 If the stock is held forever, there will be no cash flow from selling it in the future.

4 This formulation assumes that the dividend growth rate is less than the discount rate.

$$P_T = \frac{D_{T+1}}{r-g} = \frac{D_T \cdot (1+g)}{r-g} = \frac{D_T}{r-g} \cdot (1+g) = P_{T-1} \cdot (1+g). \tag{12-6}$$

In other words, given a forecast growth rate, g, the price of the stock today should equal the price last year times $(1 + g)$ or, generally, that $P_T = P_0 \cdot (1+g)^T$.

Our final step is to solve equation (12-5) for the discount rate r, which in the context of utility regulation is the appropriate return on equity value. Thus,

$$r = \frac{D_0 \cdot (1+g)}{P_0} + g = \frac{D_1}{P_0} + g. \tag{12-7}$$

Equation (12-7) is known as the *Gordon growth model*.[5] It says that the cost of equity for a regulated firm equals the stock's expected dividend yield next period (although based on today's stock price), plus the expected long-term growth in dividends over time.

Example: Calculating ROE Using the Gordon Model

Suppose we have the following data for BigElec: Today's stock price is $30/share. The forecast long-term earnings growth rate is 5%, and its current dividend payment is $2.40/share. Applying equation (12-7), the calculated ROE is:

$$r = \frac{D_0 \cdot (1+g)}{P_0} + g = \frac{\$2.40 \cdot (1+0.05)}{\$30} + 0.05 = 0.134 = 13.4\%.$$

Using the FERC methodology (see fn. 5), the calculated ROE is:

$$r = \frac{D_0 \cdot \left(1+\frac{g}{2}\right)}{P_0} + g = \frac{\$2.40 \cdot \left(1+\frac{0.05}{2}\right)}{\$30.00} + 0.05 = 0.132 = 13.2\%.$$

Thus, FERC's assumption that the firm is half-way between annual dividend payments reduces the ROE in this example by 20 basis points.

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5 M. Gordon, *The Cost of Capital to a Public Utility* (East Lansing, MI: Michigan State University Press 1974). You may encounter a slightly different version of equation (12-7):

$$r = \frac{D_0}{P_0} + g.$$

This version assumes that the first dividend is paid today, rather than at the end of the next period. (We leave the derivation as an exercise.) This version results in a lower ROE value, since the current dividend yield does not include the assumed growth in the dividend between now and the end of the first period. FERC splits the difference, using the following:

$$r = \frac{D_0 \cdot \left(1+\frac{g}{2}\right)}{P_0} + g.$$

The justification for this equation is that, on average, one is in the middle of the period between the previous annual dividend and the next annual dividend.

nationalgrid

17 May 2012

National Grid plc
Results for the year ended 31 March 2012

Steve Holliday, Chief Executive, said: *"We delivered another year of good underlying financial and operating performance despite the impact of some exceptional weather in the US. At the same time we made further progress developing the business consistent with our strategic priorities, maintaining an appropriate spread and balance of activities to support both long-term growth and dividends."*

Good performance in 2011/12

- Profit before tax[1] up 5%
- Operating profit[1] up 9% before currency movements, timing and major US storms[2]
- Continued UK outperformance
- Improved US returns - 2011 regulated return on equity up 50bp to 8.8%
- Earnings per share[1] up 1% to 51.3p, up 16% excluding timing and major storm impacts
- Recommended full year dividend up 8% to 39.28p reflecting final year of current policy

Good strategic progress

- £3.4bn of capital investment, contributing to £1.6bn growth in regulated assets
- Submitted new 8 year UK investment plans, including over £31bn of forecast capital investment
- Agreed one year rollover price control for UK transmission activities
- Implemented new US operating model. $200m run rate cost reduction target achieved
- Submitted new rate filings in upstate New York and Rhode Island in April 2012
- Balance sheet benefitted from strong cash generation and small asset disposals. As a result, net debt up only £0.9bn to £19.6bn

Positive outlook for 2012/13

- Sustain focus on improving returns and securing appropriate regulatory outcomes
- Dividend growth of 4% targeted in new one year policy

Financial results for continuing operations

(£m, at actual exchange rate)	Business performance[1]			Statutory Results		
Year ended 31 March	2012	2011	% change	2012	2011	% change
Operating profit	3,495	3,600	(3)	3,539	3,745	(6)
Profit before tax	2,585	2,473	5	2,559	2,624	(2)
Earnings per share	51.3p	50.9p	1	57.1p	62.9p	(9)

Steve Holliday added: *"In the UK, we submitted comprehensive business plans for the essential infrastructure investment needed by our UK customers in our Transmission and Distribution businesses, incorporating the results of our significant stakeholder consultation.*

In the US, our new operating model, with its regional structure and strong regulatory and consumer focus, helped us deliver our cost saving target and make essential improvements ahead of the new rate filings in upstate New York and Rhode Island.

On the back of a solid all round performance in 2011/12, and reflecting the revenue growth that our regulatory arrangements provide, we maintain a positive outlook for 2012/13, and expect to deliver another year of good operating and financial performance."

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[1] *Excluding exceptional items, remeasurements and stranded cost recoveries. For definition of business performance results see footnote 5. Prior year EPS adjusted to reflect the impact of additional shares issued as scrip dividends.*
[2] *Hurricane Irene and the 2011 October snow storm together impacted operating profit by £116m in 2011/12. Constant currency comparison uses recalculated results for 2010/11 as detailed in footnote 6.*

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CONFERENCE CALL DETAILS

An analyst presentation will be held at the London Stock Exchange, 10 Paternoster Square, London EC4M 7LS at 9:15am (GMT) today.

There will be a live webcast of the results presentation available to view at www.nationalgrid.com/investors. The presentation will be available through the same link as a replay this afternoon.

Live telephone coverage of the analyst presentation

UK dial in number	+ 44 (0) 808 109 0700	**US dial in number**	+1 212 999 6659
Confirmation Code	**National Grid**		

National Grid images can be found via the following link www.flickr.com/photos/national_grid

You can view or download copies of our latest Annual Report and Accounts (ARA) and Performance Summary from our website at www.nationalgrid.com/investors or request a free printed copy by contacting investor.relations@ngrid.com. The 2011/12 ARA and Performance Summary will be published on 12 June 2012.

BUSINESS REVIEW

National Grid delivered good underlying financial and operational performance in the year. Our strategic priorities for 2011/12 focused on delivering our core investment programme, implementing our new US operating model and achieving our cost reduction targets. Our principal other businesses, including our Grain LNG and metering businesses, also made an increased overall contribution in the year.

Our strategic priorities are intended to deliver sustainable shareholder value through growth and dividends. This requires continual focus on customer service, reliability and safety. Overall, we made improvements in a number of areas of customer satisfaction in the year but more progress is needed to ensure we are achieving a standard that meets our aspirations. We delivered record reliability in our UK Transmission business in 2011/12. We also sustained our good statistical lost time injury performance. However, this masked three tragic events where there was loss of life in the UK and the US. This has increased our determination to improve our safety performance to world class standards. These aims will sit alongside the delivery of our strategic priorities for 2012/13.

Growth and Investment

Capital investment[3] for the year was £3.4bn, £215m lower than 2010/11 reflecting reduced expenditure on non-regulated activities. Our combined UK and US regulated assets grew by £1.6bn over the course of 2011/12.

In the UK, the combination of investment and adjustments for inflation grew our Regulated Asset Value (RAV) by £1.4bn (7% up) to £22.2bn.

In the US, our total regulatory assets grew by $0.4bn to $16.4bn. This included growth of $0.2bn in US rate base and $0.2bn in regulated assets outside of rate base. The increase in US rate base was driven by continued investment, partly offset by weather related working capital movements in our New York gas businesses. The increase in US regulated assets outside rate base reflected increased work in progress in our transmission activities and increased storm deferrals in Massachusetts.

	As at 31 March		
	2012	**2011**	**Change**
Total Group regulatory assets	**32.4**	**30.8**	**1.6**
UK RAV (£bn)	**22.2**	**20.8**	**1.4**
US			
Rate base excluding working capital (w/c)	14.1	13.5	0.6
Working capital included in rate base	0.4	0.8	(0.4)
Total Rate Base	**14.5**	**14.3**	**0.2**
Regulated assets outside of rate base excluding w/c	1.4	1.2	0.2
Working capital outside of rate base	0.5	0.5	-
Total regulated assets outside rate base	**1.9**	**1.7**	**0.2**
Total US regulatory assets ($bn)*	**16.4**	**16.0**	**0.4**
Total US regulatory assets: Sterling equivalent (£bn)	**10.2**	**10.0**	**0.2**

*excludes New Hampshire assets of Granite State Electric and EnergyNorth

[3] *Including investment in joint ventures*

In the UK, we have submitted plans for our Transmission businesses and Gas Distribution businesses for the eight year RIIO period from April 2013 through to March 2021. In the US, we have recently filed for new rates in our upstate New York and Rhode Island businesses, including new capital expenditure plans. Over the eight year period from April 2013 we expect to invest around £40bn of new capital in our regulated UK and US businesses and expect to grow our group regulated asset base by an average rate of approximately 7% p.a. to over £60bn by 2021.

Our capital investment programme is crucial to maintaining the reliability and security of our UK and US networks for the benefit of customers and enabling the move to low carbon generation in the UK. Our ability to deliver these outputs in an efficient and innovative manner will be a critical factor in our performance over the next decade, in our delivery against our regulatory contracts and, as a result, in the delivery of returns to our investors.

Regulatory developments in the UK

In November 2011, Ofgem published final proposals for the one year (2012/13) **transmission price control rollover**. These included real increases in revenues for electricity and gas transmission and a base real vanilla return of 4.75%. Overall, the final proposals contained no significant changes from the initial proposals received in July 2011 and we accepted the proposals in December 2011.

In March 2012, following feedback on our initial RIIO transmission plans (the RIIO-T1 plans), we submitted updated business plans for our **UK Transmission** businesses. These set out over £30bn of total expenditure (totex) over the eight year period, including £25bn of capital expenditure (capex) as well as proposals for incentive schemes, revenue adjustment mechanisms and our view of the financing requirement for these plans.

In April 2012, again following feedback on our November plans, we submitted updated business plans for our **UK Gas Distribution** businesses (the RIIO-GD1 plans). These set out over £13bn of totex over the eight year period including over £6bn of capex, of which £5bn would be classified as replacement expenditure, and our view of the financing requirement for these plans including the accelerated recovery of some replacement expenditure.

We expect to file proposals for our two **UK system operator** incentive regimes in late May 2012. Subsequently, Ofgem's initial proposals for all of the price controls and incentive regimes are expected in July 2012 with a final decision by the end of 2012, to come into effect from 1 April 2013.

We continue to believe that customers will benefit under the RIIO framework from our ability to deliver the outputs that they want in an innovative and efficient manner. As a result, with the right balance of incentives, cash flow and risk, a satisfactory outcome on RIIO should also offer us the opportunity to earn the necessary returns on our investments while delivering value for money for the consumer.

The Queen's speech in May confirmed that **Electricity Market Reforms** will be included in the Energy Bill, which is expected to be passed into legislation during the current parliamentary session. The changes envisaged by this legislation will be instrumental in shaping investment in new generation capacity over the coming decade. It is proposed that National Grid assumes responsibility for administration of both the new capacity mechanism and the feed in tariffs that will replace the existing framework for renewable and low carbon power generation payments. This additional responsibility is not expected to have a direct material financial impact on National Grid but recognises our central role in delivering the UK's energy future.

Regulatory developments in the US

National Grid's strategy for our US business combines the delivery of further improvements in customer service and cost efficiency, investment in our regulated networks and, where appropriate, rate filings. By combining new filings with more efficient operational and capital investment processes we are seeking to achieve higher returns in the US.

In December, the **New York** Public Service Commission (NYPSC) approved National Grid's request to recover certain deferred costs and a portion of recent storm costs in our Niagara Mohawk electric business which, taken together with the planned expiry of stranded cost recoveries at the end of 2011, has allowed us to reduce bills to upstate New York electricity customers by over $300m p.a.. The NYPSC approved a total recovery of $240m, including approximately $211m out of the $236m deferred costs that National Grid filed for in July 2011, relating to pensions, environmental and other costs and capital expenditure incurred over a number of years. In addition, the NYPSC approved early recovery of approximately $25m of the storm costs associated with Hurricane Irene which affected our service territory in August 2011, subject to reviewing and confirming the actual costs at a later date. Recovery of the $240m will occur over the 15 months from 1 January 2012.

We continue to work with the NYPSC appointed consultants, Overland, in respect of the audit of our upstate New York electricity business which was commissioned by the NYPSC in 2010/11.

In April 2012, we filed for new rates with the NYPSC in respect of our Niagara Mohawk gas and electric businesses. These plans include the benefits of reduced costs related to our US restructuring programme and further investment in new capital to secure a safe and reliable infrastructure. Overall, the new rate filing as submitted, including the scheduled end of deferral recoveries, should result in a further reduction to consumer electric bills in the Niagara Mohawk region through a revenue reduction of around $60m p.a. and a modest increase in gas bills through a revenue increase of just over $10m p.a. while enabling the businesses to deliver improved regulatory returns on equity. The rate filing process is expected to take 11 months and to be completed by the end of the first quarter of 2013.

Our appeal of certain aspects of the **Rhode Island** Commission's last electric rate order in 2010 was concluded in January 2012. As a result, increased rates came into effect on 23 April 2012, reflecting the use of an increased equity ratio in the calculation of the level of allowed return.

At the end of April 2012, we filed new rate cases for our businesses in Rhode Island. The filings seek an increase in rates of $20m p.a. for the gas business and $31m p.a. for the electric business to permit further improvements to customer service, match our revenues to our costs, and update our rate base to fully remunerate the Company for past investments not yet reflected in rates. The rate filing process is expected to take around 9 months.

In December the **Long Island** Power Authority (LIPA) announced that National Grid had not been selected to continue to manage and operate Long Island's electricity system beyond the term of the current Management Services Agreement which expires on 31 December 2013. In 2011/12, the operating profit contribution from the contract was around one percent of the Group's operating profit and no rate base is associated with the contract.

Overall we have seen another year of measured progress developing our regulatory arrangements. Taken together with the benefit of our efficiency programmes, this progress underpins our confidence that we will be able to deliver improved returns from our US operations.

Efficiency Programmes

National Grid has a number of efficiency programmes underway in different parts of its business to ensure the cost effective delivery of our services and investments.

Our UK Gas Distribution Front Office system rollout is approaching completion, with a number of operational improvements already being realised. In addition, we have implemented a revised UK Gas Distribution structure, involving a number of management and staff changes. These initiatives are designed to bring our businesses closer to the efficiency frontier for all UK gas networks, a target which we believe is well supported by our RIIO-GD1 business plans.

Implementation of our new US organisational model has been completed, together with a reduction of over 1,150 mostly management and administrative positions. As a result, taken together with the related cost saving initiatives announced last year, we reached our target of delivering a $200m cost savings run rate by the end of March 2012.

Compared to 2010/11, our total regulated controllable operating costs[4] increased in nominal terms by £5m, representing a year on year reduction of 3% in real terms. Together with the growth in our asset base, this resulted in our efficiency metric improving to 6.7% from 7.2%.

Strategy

The Group's strategy is unchanged. In early 2011/12 we set out how maintaining an appropriate mix of businesses enables our portfolio of activities to deliver an overall balance between long-term capital growth and cash generation for the benefit of our shareholders. We own developed assets with minimal investment requirements and strong cash generation such as our existing Grain LNG assets, businesses with low to medium levels of growth and positive cash generation including our distribution activities and businesses with high levels of investment and growth such as electricity transmission.

In addition to considering its contribution to the overall balance, where a business is not expected to exhibit the range of characteristics we are looking for within a reasonable timeframe, or where we are offered a higher value for the business than we might place on it, we will consider selling that business.

In this context, we made a number of small divestments. In 2011, we sold our US exploration and production business, Seneca-Upshur, for $153m and OnStream, our UK unregulated metering business, for £274m.

Improving US and sustaining appropriate UK returns

In May last year we set out a clear framework for assessing operating returns, as a measure of regulatory performance, and overall returns on equity, as a measure of shareholder value creation. We supplemented this in November by introducing a new Return on Capital Employed (RoCE) metric in particular to aid comparison of the value created by our UK and US operations.

Our underlying objective is to deliver improved sustainable returns in the US and ensure we continue to deliver appropriate returns in the UK while investing in essential infrastructure to reinforce our networks.

Returns on our Regulated Arrangements

In the **UK**, our performance compared to our regulatory contracts is assessed by directly comparing our achieved operational real returns with those we are allowed. This builds in the appropriate drivers that

[4] *Regulated controllable operating costs exclude bad debts, pension and other post employment benefit costs and are presented on a constant currency basis.*

have been agreed with the regulator including incentives for emissions reduction, efficiency, and in the future, innovation.

UK Operational return (real)	2011/12	2010/11	2009/10	*Allowed*
UK Electricity Transmission	**5.6%**	6.4%	6.6%	*5.05%*
UK Gas Transmission	**7.3%**	7.2%	7.6%	*5.05%*
UK Gas Distribution	**5.7%**	5.5%	6.3%	*4.94%*

We continued to deliver returns above those allowed, reflecting robust incentive performance and underlying efficiency. Outperformance on operating costs and revenue from incentive mechanisms were the main drivers of returns above the allowed level in UK Gas Transmission and UK Gas Distribution. Despite reduced incentive performance in 2011/12, our UK Electricity Transmission business also delivered a return above the level assumed at the time the price control was set.

In the **US**, our performance can be assessed by looking at the overall achieved regulated return on equity. Regulated operating companies will typically file rate cases when their revenues are not aligned with the cost of performing the utility service or when the need for future rate relief is anticipated because of new obligations, capital spending increases, or other similar factors. When costs are not being adequately recovered, a key indicator for the need to file a rate case is a lower achieved return than that which the company could reasonably expect to be granted through a new rate case. Where this applies to our US operating companies, rate filings are underway or are being planned.

Regulated return on equity	Achieved (%) Calendar year			*Most recent granted (%)*
US Regulated Entity	**2011**	2010	2009	
New York				
KEDNY	**11.9**	11.9	11.0	*9.8*
KEDLI	**9.4**	10.0	10.7	*9.8*
NMPC Gas**	**6.5**	7.6	5.1	*10.2*
NMPC Electric**	**5.6**	6.1	4.5	*9.3*
Total New York*	**8.0**	**8.4**	**7.4**	***9.6***
Massachusetts and Rhode Island				
Massachusetts Gas	**10.6**	3.5	3.6	*9.75*
Massachusetts Electric	**9.5**	10.0	4.5	*10.35*
Narragansett Gas**	**6.4**	0.6	5.8	*10.5*
Narragansett Electric**	**7.6**	8.3	(3.4)	*9.8*
Total Massachusetts and Rhode Island*	**9.4**	**6.7**	**3.0**	***10.1***
FERC				
Long Island Generation	**12.4**	11.2	13.5	*10.75*
New England Power	**11.1**	11.6	11.8	*11.14*
Canadian Interconnector	**12.0**	13.0	13.0	*13.0*
Narragansett Electric, Transmission	**11.6**	11.8	11.5	*11.14*
Total FERC*	**11.6**	**11.5**	**12.4**	***11.1***
Total US*	**8.8**	**8.3**	**6.9**	***9.9***

* total return weighted by average rate base
** rate filings made in April 2012

Overall, our businesses in the US delivered an improved average return of 8.8% in the calendar year 2011. The improvement was largely driven by cost saving initiatives and the benefit of new rate filings, partially offset by volume related revenue benefits that increased reported returns in 2010 in Niagara Mohawk (NMPC) Electric.

Comparative performance between our UK and US businesses

Over time we would expect the Return on Capital Employed in our UK and US businesses to converge somewhat, while both sustaining an appropriate degree of outperformance compared to a relevant weighted average cost of capital. This would reflect our view that the US regulatory environment can offer investors comparable returns to the UK while incentivising investment in reliable infrastructure and improved customer service. The RoCE for our businesses over the last three years is shown in the table below:

RoCE	2011/12	2010/11	2009/10
UK Regulated	8.6%	8.5%	9.6%
US Regulated	7.6%*	7.1%	5.5%

* Adjusted for £116m of storm costs associated with Hurricane Irene and the October 2011 snow storm.

The movement in UK Regulated RoCE was principally caused by increased operating profit driven by RPI indexation on revenues. In the US, the improvement in RoCE reflected the benefit of cost saving initiatives and the full year effect of rate filings agreed in previous years.

Group level Return on Equity

Overall, we have sustained our group level Return on Equity (RoE) at a double digit level. We have updated our RoE calculation to bring the definitions and approaches in line with those used for the RoCE calculation. The principal changes are removing timing volatility from revenues and using a constant long-term average inflation assumption rather than an actual annual figure, which has also caused volatility and tended to increase returns in recent years above expected long run levels. Under the updated measure the actual Group ROE in 2011/12, excluding the impact of major storms, was 11.3% for the year compared to 10.8% in 2010/11, reflecting the impact of increased operating profit (excluding timing) mostly offset by the increase in the equity funded portion of the rate base, driven partly by the RPI uplift on UK regulatory asset value. A detailed breakdown of the Group RoE calculation is shown on page 24.

Board changes

In December 2011, Sir John Parker stepped down from his position as Chairman of the Board of National Grid after over 10 years as Chairman of National Grid and previously Lattice Group. Sir Peter Gershon joined the Board as Deputy Chairman on 1 August and assumed the role of Chairman of the Board of National Grid with effect from 1 January 2012.

In July 2011, John Allan, a non-executive director of National Grid for the last six years, stepped down from the Board. In October 2011, Ruth Kelly, Managing Director, HSBC Global Asset Management and a former UK government minister, joined the Board as a Non-executive Director.

On 1 February 2012, Dr Paul Golby, Chairman of Engineering UK and a member of the Council for Science and Technology, and formerly Chief Executive and Chairman of E.ON UK plc, joined the Board as a non-executive Director.

In April 2012, we announced that Nora Mead Brownell, a former Commissioner of the Pennsylvania Public Utility Commission and the Federal Energy Regulatory Commission, would join the Board as a non-executive Director with effect from 1 June 2012.

It is expected that further new non-executive directors will be appointed over the period until July 2014, to ensure that essential skills and experiences are retained during a phased and orderly transition of the Board. Stephen Pettit and Linda Adamany will step down from the Board with effect from 30 July and 31 October 2012 respectively. Ken Harvey, Senior Independent Director and Remuneration Committee chairman, and George Rose, Audit Committee chairman, are expected to stay on the Board until July 2013, allowing time for suitably qualified and experienced external candidates to be appointed. Maria Richter, Finance Committee chairman, who has significant financial expertise, is expected to step down in July 2014.

DIVIDEND

The Board has recommended an increase in the final dividend to 25.35p per ordinary share ($2.0166 per American Depositary Share) in line with our policy of targeting 8% growth until March 2012, bringing the full year dividend to 39.28p per ordinary share. If approved, the final dividend will be paid on 15 August 2012 to shareholders on the register as at 1 June 2012. A scrip dividend alternative will again be offered.

Our dividend is an important part of our returns to shareholders along with growth in the value of the asset base attributable to equity holders. The financial year 2011/12 was the last year of National Grid's current dividend policy which had been in place since January 2008. The Board has agreed a new one year dividend policy under which we plan to increase the 2012/13 dividend by 4% in nominal terms over the proposed dividend of 39.28p for 2011/12. This policy reflects the outcome from the one year rollover review of the UK Transmission price control and forecast UK inflation of around 3% for the same period. This new dividend policy will apply to the interim dividend to be paid in January 2013 and the final dividend to be paid in August 2013.

As previously stated, we expect to announce a new dividend policy for the period from April 2013 during the course of 2013, once outcomes of key regulatory developments are clear.

OUTLOOK

Our strategic priorities for 2012/13 are: delivering our investment programme in a disciplined manner; improving returns in our US business; finalising the development of the UK regulatory framework and continuing to drive efficiency across the business.

The restructuring of our US business is now complete and is delivering operational and financial benefits to underpin our progress on further improving US returns. Our existing price controls in the UK continue to deliver attractive returns and we are working to ensure that this can continue under the RIIO framework.

On the back of a solid all round performance in 2011/12, and reflecting the revenue growth that our regulatory arrangements provide, we maintain a positive outlook for 2012/13, and expect to deliver another year of good operating and financial performance.

BASIS OF PRESENTATION

Unless otherwise stated, all financial commentaries are given on a business performance basis[5] at actual exchange rates. The results for the year are presented in line with the new reporting structure, separated into segments for our UK Transmission, UK Gas Distribution and US Regulated businesses. The results for 2010/11 have also been re-presented in these new segments.

Under our regulatory frameworks, the majority of the revenues that we are allowed to collect each year are governed by a regulatory price control or rate plan. If we collect more than this allowed level of revenue, the balance must be returned to customers in subsequent years, and if we collect less than this level of revenue we may recover the balance from customers in subsequent years. These variances between allowed and collected revenues give rise to "over and under recoveries". In addition, in the US, a substantial portion of our costs are pass-through costs (including commodity and energy efficiency costs), and are fully recoverable from customers. These timing differences between costs of this type being incurred and their recovery through revenues are also included in over and under-recoveries. We identify these timing differences in order to enable a better comparison of performance from one period to another. Opening balances of under and over-recoveries have been restated where appropriate to correspond with regulatory filings and calculations.

REVIEW OF RESULTS AND FINANCIAL POSITION

Operating profit (£m)	**Year ended 31 March 2012**	**2011**	**% change**
UK Transmission	**1,354**	1,363	(1)
UK Gas Distribution	**763**	711	7
US Regulated	**1,190**	1,407	(15)
Other activities	**188**	119	58
Operating profit – actual exchange rate	**3,495**	3,600	(3)
Operating profit – constant currency	**3,495**	3,579	(2)
Timing and storm adjustment	**98**	(274)	
Operating profit – constant currency excluding major storms and timing	**3,593**	3,305	9

Other items – constant currency[6] (£m)	**Year ended 31 March 2012**	**2011**	**% change**
Depreciation	**(1,267)**	(1,238)	(2)
Net Finance costs	**(917)**	(1,124)	18

Other items – actual exchange rates (£m)	**Year ended 31 March 2012**	**2011**	**% change**
Depreciation	**(1,267)**	(1,245)	(2)
Net Finance costs	**(917)**	(1,134)	19
Taxation	**(755)**	(722)	(5)
Earnings attributable to equity shareholders	**1,828**	1,747	5

[5] Business performance results are the primary financial performance measure used by National Grid, being the results for continuing operations before exceptional items, remeasurements and stranded cost recoveries. Remeasurements comprise gains or losses recorded in the income statement arising from changes in the fair value of commodity contracts and of derivative financial instruments to the extent that hedge accounting is not achieved or is not fully effective. Stranded cost recoveries are costs associated with historical generation investment and related contractual commitments that were not recovered through the sale of those investments. Commentary provided in respect of results after exceptional items, remeasurements and stranded cost recoveries is described as 'statutory'. Further details are provided in note 3 on page 35. A reconciliation of business performance to statutory results is provided in the consolidated income statement on page 27.
[6] 'Constant currency basis' refers to the reporting of the actual results against the results for the same period last year which, in respect of any US$ currency denominated activity, have been translated using the average US$ exchange rate for the year ended 31 March 2012, which was $1.60 to £1.00. The average rate for the year ended 31 March 2011, was $1.57 to £1.00.

Operating profit was £3,495m, down £84m (2% lower) compared to last year on a constant currency basis. This reflected an adverse year-on-year timing impact of £256m:

Over/(under)-recovery (£m – constant currency)	Year ended 31 March 2012	2011	Year-on-year change
Balance at start of period (restated)	72	(202)	
In-year over/(under)-recovery	18	274	**(256)**
Balance at end of period	90	72	
Operating profit	3,495	3,579	**(84)**
Adjust for timing differences	(18)	(274)	**256**
Operating profit excluding timing	3,477	3,305	**172**

As a result, **operating profit excluding the impact of timing** increased by £172m (5% up) on a constant currency basis. This increase was partly driven by an increase of £68m in our other activities, principally our Grain LNG and our UK metering businesses. In our regulated businesses, net income increased by £224m partly due to the impact of RPI+X indexation on our UK regulated revenues. Regulated controllable costs increased by £5m. In addition, Hurricane Irene and the October 2011 snow storm decreased operating profit by a further £116m. Depreciation and amortisation increased by £39m and other costs including property taxes increased by £10m. Post-retirement costs[7] decreased by £36m and bad debts decreased by £14m.

The year-on-year movement in exchange rates had a £21m negative impact on operating profit.

Across our businesses, **regulated controllable costs** increased by £5m (less than 1%) on a constant currency basis compared to last year, reflecting inflationary impacts on salaries and other costs and increased recruitment in our UK Transmission business. The continued drive for efficiency in our businesses and benefits from our US cost saving programme helped to mitigate these impacts. Adjusting for inflation, regulated controllable costs reduced by 3% in real terms.

Net finance costs were £917m, 18% lower than 2010/11 at constant currency partly driven by lower average net debt, the impact of debt buy back costs in 2010/11 and lower pension interest. In addition the level of provision discount unwind in 2011/12 decreased, offset by an increased charge against operating profit, principally in our US regulated business.

Our **effective interest rate** on Treasury managed debt for the year was 5.4% compared to 5.8% in 2010/11.

Interest cover was 3.9x, compared to 3.8x in the previous year and still comfortably above our target range of 3.0 to 3.5x.

Profit before tax was up 5% to £2,585m. Excluding the impact of timing and major storms, profit before tax increased by 23% at constant currency.

The **tax charge** on profit was £755m, £33m higher than 2010/11, reflecting increased profits before tax. Our **effective tax rate** was unchanged at 29.2%.

The share **of post tax results of joint ventures and associates** was £7m, unchanged from 2010/11.

Earnings attributable to non-controlling interests decreased to £2m from £4m in 2010/11.

[7] *Post-retirement costs include the cost of pensions and other post employment benefits*

As a result, earnings attributable to equity shareholders were up £81m compared to 2010/11 at £1,828m. **Earnings per share** increased 1% from 50.9p last year (restated for the impact of shares issued under the scrip dividend programme) to 51.3p. Excluding the impact of timing and major storms, earnings per share increased by 16% year on year to 53.0p.

Exceptional items, remeasurements and stranded cost recoveries increased statutory earnings by £208m after tax. A detailed breakdown of these items can be found on page 35. After these items and non-controlling interests, statutory earnings for continuing operations attributable to equity shareholders were £2,036m.

Statutory basic earnings per share from continuing operations were 57.1p compared with 62.9p (restated) last year.

Operating cash flow, before exceptional items, remeasurements, stranded cost recoveries and taxation, was £4,445m, £213m lower than 2010/11 principally reflecting lower operating profit and higher pension contributions.

Funding and net debt

The Group's funding position continues to be supported by strong cash flows from operations and appropriate credit ratings, providing sufficient balance sheet capacity to fund our investment commitments for at least the medium term. **Net debt** rose to £19.6bn at 31 March 2012 compared with £18.7bn at 31 March 2011, reflecting the impact of our investment programme, accretions on index linked debt and some effects of foreign exchange movements, which increased net debt by £56m due to the strengthening of the US dollar.

Over the course of 2011/12 we continued to issue long term debt where attractive opportunities arose. During the year we issued a total of just over £280m of index-linked retail bonds from National Grid plc at a real coupon of 1.25%. This is the largest retail bond issued in the UK and the first index-linked retail bond ever issued by a company in the UK debt markets. We also issued a 4 year maturity €500m note from National Grid USA in May, paying a coupon of 3.25%, alongside bonds from Boston Gas, Colonial Gas and National Grid Electricity Transmission plc.

TECHNICAL GUIDANCE

We provide technical guidance to aid consistency across a range of modeling assumptions of a technical, rather than trading or core valuation, nature. We will provide appropriate updates to this information on a regular basis as part of our normal reporting. The outlook and technical guidance contained in this statement should be reviewed together with the forward looking statements set out in this release in the context of the cautionary statement.

Earnings Items

Operating profit of £3,495m for the year included a number of **timing differences**, together totaling £18m. Excluding these timing differences, operating profit for the year would have been £3,477m

UK operations

We expect **UK inflation** to contribute approximately £75m to an increase in our Gas Distribution allowed regulated RPI+X linked revenues in 2012/13.

The **one year transmission rollover review** in the UK increased the level of allowed revenues for 2012/13 by approximately £200m compared to 2011/12 including the impact of forecast inflation.

UK controllable **costs** and **depreciation** are both expected to increase, reflecting continued inflation and technical staff recruitment and the impact of the recent high levels of capital investment.

US operations

The **Niagara Mohawk deferral recoveries** impacted the last 3 months of 2011/12 only and we would expect a full year on year impact for 2012/13 of approximately £90m.

Further reductions in **US regulated controllable operating costs** as a result of the 2011/12 restructuring programme are expected to be at least offset by inflation and other cost increases.

The incremental **US storm costs** of around £116m experienced in 2011/2 are not expected to recur in 2012/13.

Group

Net finance costs are expected to be around £100m higher in 2012/13, reflecting an increase in average net debt and a slightly higher effective interest rate.

For the full year 2012/13, we expect our **effective tax rate** to be around 30%.

Investment and other items

Capital expenditure for 2012/13 is expected to be in the range £3.5bn to £3.8bn, reflecting increased investment in our UK Transmission business including work on the London power tunnels, the Western HVDC connection between Scotland and North Wales, and other network renewal and reinforcement projects.

Net debt is expected to increase by around £1.5bn during 2012/13, excluding the effect of any exchange rate impacts.

REVIEW OF UK TRANSMISSION OPERATIONS

(£m) Summary results	Year ended 31 March 2012	2011	% change
Revenue	3,804	3,484	9
Operating costs	(2,019)	(1,721)	(17)
Depreciation and amortisation	(431)	(400)	(8)
Operating profit	**1,354**	**1,363**	**(1)**
Capital investment	**1,397**	**1,432**	**(2)**
Regulated Asset Value			
Electricity Transmission	9,136	8,388	9
Gas Transmission	5,100	4,889	4
Total Regulated Asset Value	**14,236**	**13,277**	**7**

Operational return (real)	Year ended 31 March 2012	2011
Electricity transmission	**5.6%**	6.4%
Gas transmission	**7.3%**	7.2%

Performance in 2011/12

UK Transmission **operating profit** was down £9m (1% lower) compared to 2010/11. This included an estimated under-recovery of revenues of £21m in our regulated businesses. Combined with an opening balance of £7m owed to the business from previous years, this leaves a total balance owed to our businesses as at 31 March 2012 of £28m. In 2010/11, revenues were over-recovered by an estimated £70m. Adjusting for these net negative timing differences of £91m, operating profit for the year excluding timing increased by £82m, or 6%.

Over/(under)-recovery (£m) (estimated)	Year ended 31 March 2012	2011	Year-on-year change
Balance at start of period (restated)	(7)	(77)	
In-year over/(under)-recovery	(21)	70	**(91)**
Balance at end of period	(28)	(7)	
Operating profit	1,354	1,363	**(9)**
Adjust for timing differences	21	(70)	**91**
Operating profit excluding timing	1,375	1,293	**82**

The increase in operating profit excluding timing reflected higher net income of £148m driven by £110m of RPI+X indexation on UK regulated revenues partly offset by £18m lower French Interconnector auction revenues as a result of outages taken for essential maintenance. Despite a record year of network reliability, Transmission's performance on its annual incentive schemes was mixed, with the overall result being £39m lower than last year. Virtually all of this reduction related to the current two year electricity balancing services incentive scheme (BSIS), at the halfway point of which a £20m charge has been recorded. In the one year BSIS scheme applicable in 2010/11 Transmission earned a £15m incentive profit. Increased entry and exit capacity revenues mostly offset the impact of annual incentive schemes, and overall our system operator performance remains good.

Depreciation and amortisation increased by £31m, reflecting the growth in asset base due to our investment programme. In addition, regulated controllable costs increased by £24m mainly reflecting further investment in workforce renewal and growth as the business continues to prepare for an increase in investment workload. Post-retirement costs increased by £1m and other costs increased by £10m.

Transmission's UK regulated electricity and gas transmission businesses achieved operational returns of 5.6% and 7.3% respectively, outperforming our base regulatory assumptions for the year. The larger level of outperformance in the gas transmission business continues to be driven by additional revenues from entry and exit incentive schemes. Lower returns in our electricity transmission business reflected the BSIS charge.

We have continued with a number of initiatives designed to prepare the business for a period of increased capital expenditure and maintain our focus on efficiency and customer service. As part of this preparation, we have also enhanced our internal capabilities by recruiting around 300 skilled engineers. Continuing with our focus on customer service, we published our Transmission customer commitment detailing how we will communicate with customers and deliver what they need while we are significantly expanding our existing network.

As outlined in the Business Review, we accepted the final proposals for the one year transmission price control and filed our updated business plans for RIIO in March 2012. We expect Ofgem's initial RIIO proposals in July 2012 and final proposals towards the end of 2012, with the control running for eight years from 1 April 2013.

Throughout the RIIO engagement process our stakeholders have maintained that the reliability of our system is extremely important to them. In 2011/12 we delivered record reliability in our electricity transmission business, comfortably exceeding the target level of 99.9999% of energy delivered as measured by the regulatory incentive mechanism.

Investment activities in 2011/12

Capital investment in UK Transmission was £1,397m, 2% lower than 2010/11. Investment in new gas transmission pipelines reduced compared to last year and contributed to an approximately £60m reduction in gas transmission spend. Partly offsetting this, we increased capital investment in electricity transmission by around £30m. We have increased investment in our London power tunnels project and are continuing to invest in other major load related projects including the Western HVDC connection. We also sustained our significant programme of non-load related investment to enhance the security, reliability and efficiency of our system through asset renewal.

Future activities and outlook

The outlook for UK Transmission in 2012/13 is positive, driven by the increased revenue from the one year rollover of the transmission price control review. We expect continued upward pressure on operating costs, in part due to our recruitment of more engineers to deliver our investment programme.

In the longer term, we expect to invest around £30bn of capital and operating expenditure in our UK regulated transmission businesses in the eight years to March 2021, with capital investment in 2012/13 expected to increase to over £1.5bn. We are focusing on continuing improvement in our capital delivery processes, ensuring that we are well positioned by the end of 2012/13 to deliver under the new RIIO incentive regimes.

REVIEW OF UK GAS DISTRIBUTION OPERATIONS

(£m)	Year ended 31 March		
Summary results	**2012**	**2011**	**% change**
Revenue	1,605	1,524	5
Operating costs	(591)	(595)	1
Depreciation and amortisation	(251)	(218)	(15)
Operating profit	**763**	**711**	**7**
Capital investment			
Capital expenditure	171	193	(11)
Replacement expenditure	474	476	0
Capital investment	**645**	**669**	**(4)**
Regulated asset value	**7,940**	**7,520**	**6**

	Year ended 31 March	
	2012	**2011**
Operational return (real)	**5.7%**	5.5%

Performance in 2011/12

UK Gas Distribution **operating profit** was up £52m (7% higher) compared to 2010/11. This included an estimated over-recovery of revenues of £22m in our regulated businesses. Combined with an opening balance of £20m owed to the business from previous years, this leaves a total balance owed by our businesses as at 31 March 2012 of £2m. In 2010/11, revenues were over-recovered by an estimated £4m. Adjusting for these net timing differences of £18m, operating profit for the year excluding timing increased by £34m, or 5%.

Over/(under)-recovery **(£m)** (estimated)	Year ended 31 March **2012**	**2011**	**Year-on-year change**
Balance at start of period (restated)	(20)	(24)	
In-year over/(under)-recovery	22	4	**18**
Balance at end of period	2	(20)	
Operating profit	763	711	**52**
Adjust for timing differences	(22)	(4)	**(18)**
Operating profit excluding timing	741	707	**34**

The increase in **operating profit excluding timing** reflected increased net income of £72m, driven by the impact of RPI+X indexation and an increase in non-regulated income of £9m from increased customer connections and asset disposals, partly offset by phasing of replacement incentive income. Regulated controllable costs increased by £11m, principally due to the impacts of inflation and resources to support the implementation of new systems. Depreciation and amortisation increased by £33m largely reflecting the investment in new systems and accelerated depreciation related to the decommissioning of gas holders. Other costs reduced by £5m primarily reflecting lower environmental charges. Post-retirement costs decreased by £1m.

We achieved an estimated 5.7% real operational return, outperforming base regulatory assumptions and improving by 20bps on the 5.5% achieved in 2010/11. This was mainly as a result of outperformance on operating expenditure and incentives, including improved performance on the mains and services replacement incentive.

As part of our drive to improve efficiency and customer service we are restructuring and transforming our Gas Distribution operations. We have made improvements in both areas, with customer satisfaction improving whilst holding underlying regulated operating costs broadly flat in real terms compared to last year.

The Gas Distribution Front Office (GDFO) system rollout continues to make good progress. New technology has been successfully introduced for our emergency and maintenance as well as our customer service operations. As a result, we have started to generate meaningful improvements in productivity and response times in key areas. For example, our maintenance process is now seeing significant operational improvements, despite some early challenges when the system was first introduced in 2010. Maintenance productivity has improved by 16% compared to pre-implementation levels and our on time response to faults also improved significantly.

As part of the investment, we have also replaced telephony hardware and introduced a new customer service solution for the national gas emergency service. The new system provides information on job progress and previous work at our customers' premises which enables us to communicate issues rapidly to and from our engineers in response to customers' needs. We have already seen an improvement in service levels and expect this will support further enhancement of customer satisfaction.

The benefits of the GDFO investment underpin the improved operational performance forecast we submitted to Ofgem as part of our RIIO-GD1 business plans.

In February 2012, Ofgem imposed a £4.3m penalty on us for our performance during the severe winter of 2010/11 when we failed to meet standards of service required for gas escapes in our four networks. In 2011/12 we met all of our standards of service.

As outlined in the Business Review, we filed our updated business plans for the period April 2013 to March 2021 with the regulator in April as part of the RIIO price control process.

Investment activities in 2011/12

Capital investment in our UK Gas Distribution business continues to be dominated by our work on mains replacement, which accounted for £474m (2010/11 £476m) of our total £645m capital expenditure for the year. During the year, together with our gas distribution alliance and coalition partners, we replaced around 1,980km of gas mains in the UK. In 2011, the HSE published a revised methodology for prioritising the replacement of large diameter metallic mains, which is reflected in reduced replacement expenditure assumptions under our RIIO business plans. This has not impacted replacement activity in 2011/12.

Future activities and outlook

The outlook for our UK Gas Distribution business for 2012/13 is for another year of good performance, driven by RPI linked revenue increases under our regulatory arrangements and a continued focus on operating costs, combined with the start of significant benefits expected from our efficiency initiatives.

As outlined in the Business Review, we expect Ofgem's initial proposals for the RIIO price control in July and final proposals in December 2012. This price control, alongside our work to deliver outputs in an innovative and efficient manner, will underpin the performance of our UK distribution business for the eight years from April 2013.

National Grid
2011/12 Full Year Financial Information

REVIEW OF US REGULATED OPERATIONS

(£m)	Year ended 31 March		
Summary results	**2012**	**2011**	**% change**
Revenue	7,516	8,391	(10)
Operating costs	(5,920)	(6,546)	10
Depreciation and amortisation*	(406)	(438)	7
Operating profit – actual exchange rate	**1,190**	**1,407**	**(15)**
Operating profit – constant currency	**1,190**	**1,385**	**(14)**

* excludes amortisation of intangibles

(£m, at actual exchange rate)			
Capital investment	**1,052**	**1,092**	**(4)**

	Rate Base ($'m) Year ended 31 March		Achieved regulated return on equity (%) Calendar year	
US Regulated Entity	**2012**	**2011**	**2011**	**2010**
New York				
KEDNY	2,048	2,162	11.9	11.9
KEDLI	1,806	1,931	9.4	10.0
NMPC Gas	980	832	6.5	7.6
NMPC Electric	3,861	3,722	5.6	6.1
Total New York*	**8,695**	**8,647**	**8.0**	**8.4**
Massachusetts and Rhode Island				
Massachusetts Gas	1,316	1,280	10.6	3.5
Massachusetts Electric	1,677	1,659	9.5	10.0
Narragansett Gas	332	324	6.4	0.6
Narragansett Electric	544	602	7.6	8.3
Total Massachusetts and Rhode Island*	**3,869**	**3,865**	**9.4**	**6.7**
FERC				
Long Island Generation	470	504	12.4	11.2
New England Power	965	918	11.1	11.6
Canadian Interconnector	45	55	12.0	13.0
Narragansett Electric, Transmission	427	284	11.6	11.8
Total FERC*	**1,907**	**1,761**	**11.6**	**11.5**
Total US* +	**14,471**	**14,273**	**8.8**	**8.3**

* total return weighted by average rate base
+ excluding New Hampshire businesses of Granite state and EnergyNorth

Performance in 2011/12

On a constant currency basis US **operating profit** was down £195m (14% lower) from prior year at £1,190m. This included an over-recovery of revenue in the year of £17m. Combined with an opening balance of £99m owed to customers from previous years, this leaves a total balance owed to customers as at 31 March 2012 of £116m. In 2010/11, revenues were over-recovered by £200m. Adjusting for these net timing differences of £183m, operating profit for the year excluding timing decreased by £12m or 1%.

Over/(under)-recovery (£m – constant currency)	**Year ended 31 March 2012**	**2011**	**Year -on-year change**
Balance at start of period	99	(101)	
In-year over/(under)-recovery	17	200	(183)
Balance at end of period	116	99	
Operating profit at constant currency	1,190	1,385	(195)
Adjust for timing differences	(17)	(200)	183
Operating profit excluding timing	1,173	1,185	(12)

The reduction in **operating profit excluding timing** included a £72m charge in respect of Hurricane Irene and a £44m charge related to the October 2011 snow storm. Excluding the impact of these weather events and the effect of timing, operating profit increased by £104m or 9%.

Key drivers of the operating profit improvement included a reduction in regulated controllable costs of £30m, reflecting restructuring and efficiency savings offset by some inflationary impacts. A decrease in post-retirement costs of £36m, of which around £16m were one-off, and a bad debt reduction of £14m also benefitted operating profit. In addition, operating profit was benefitted by a net income increase of £20m partly due to new rates authorised in previous years and increased revenue in our FERC business, offset in part by a year-on-year reduction in our Niagara Mohawk electric business where hot summer weather increased revenue in 2010/11. Operating profit was not impacted by an adjustment to asset lives as part of the Niagara Mohawk rate case outcome which reduced both revenue and depreciation by an additional £16m. Other depreciation and amortisation decreased by £9m, reflecting the cessation of depreciation in relation to our New Hampshire assets and other operating costs increased by £5m. The year-on-year movement in exchange rates had a £22m unfavourable impact on operating profit.

Our US service areas were impacted by unprecedented weather conditions. A rare tornado and unseasonable heavy snow in October 2011, together with flooding in upstate New York and Hurricane Irene, caused widespread damage. At one stage, outage reports showed that 1.4 million National Grid and LIPA customers were without power as a result of Hurricane Irene. This unprecedented level of bad weather resulted in a very large restoration effort across our businesses.

The bulk of the costs associated with this recovery effort not already covered by storm funds are recoverable through appropriate filings across our US jurisdictions, subject to the review of the applicable regulator. As a result, they do not significantly impact reported RoEs for the calendar year 2011.

The achieved RoE of our **Massachusetts Gas** business improved significantly over the previous year, driven by implementation of the new rate case announced in November 2010. In addition, the Massachusetts Department of Public Utilities issued an order in response to our request to correct certain calculation errors appearing in that gas rate case order. The new order issued approved a further increase in gas distribution rates of $2.8m p.a.

As expected, achieved RoEs in our upstate **New York** and **Rhode Island** electric utilities declined compared to the previous year, when the businesses benefited from weather related volumes prior to decoupling. These businesses are earning low rates of return, principally driven by the fact that the operating costs are above the level assumed by the relevant regulator when setting rates. As a result, we have filed for new rates in these businesses and have also filed for new rates for our gas businesses in these areas. In KEDLI, our Long Island Gas distribution business, the achieved RoE declined in 2011 due to higher depreciation and property tax expenses.

During the year, we implemented our **cost reduction programme**, delivering the target we set of a run rate of $200m of savings over real 2009/10 levels. In addition we have made a number of changes to our organisational model, accounting systems and processes with the objective of being responsive to our regulators and customers in each of the jurisdictions in which we operate. This jurisdictional focus is already providing a much stronger alignment around managing regulatory engagement and customer service, as well as delivering necessary changes to our controls and accounting processes, in line with the recommendations set out in the recent Liberty Consulting Group audit of our US operations.

For the calendar year 2011 we met all but two of our regulatory reliability and customer service standards, with the benefit of good performance under a number of standards almost entirely offsetting any financial penalty associated with the missed targets.

Investment activities in 2011/12

Capital investment in our regulated US business continues at a broadly steady rate. Capital expenditure for the year was £1,052m, £40m lower than 2010/11, partly due to movements in exchange rates. On a constant currency basis, capital investment was £23m lower than 2010/11. We increased spend on the New England East-West System transmission project, offset by lower spend in our upstate New York electric business.

Five years ago we agreed to a material increase in capital expenditure in our upstate New York electricity business. In 2011/12, ahead of schedule, we completed the $1.5bn programme that was agreed, making significant progress in upgrading an ageing network and continuing to provide safe, reliable power to more than 1.6 million customers in the region. We have met our service quality and reliability targets every year since 2007 in the region and expect to continue to invest at this enhanced rate for some time to sustain this performance.

Future activities and outlook

The outlook for our US business for 2012/13 is positive with the business set to benefit from our deferral recoveries in upstate New York. Year on year performance should also reflect a non-repeat of the major storms in 2011/12.

2012/13 will be a year of significant work on the integration of our multiple information systems in the US. This initiative includes the implementation of a single financial system across all of our US businesses designed to deliver significant improvements to data accuracy and cost allocation, which will underpin our regulatory engagement and support future rate filings.

The loss of the contract to operate the transmission and distribution system on Long Island is not expected to impact results materially for 2012/13 since the contribution to Group operating profit is around 1% of group total and the contract runs until December 2013. We will work to ensure a smooth transition for the benefit of customers and our affected employees.

Capital investment in our US activities is expected to continue within our medium term guidance of £1.0bn - £1.2bn per annum, largely reflecting the benefit of a stronger regional focus on prioritising activities and remaining consistent with the expectations of our regulators.

REVIEW OF OTHER ACTIVITIES

(£m – actual exchange rate)	Year ended 31 March		
Summary results	**2012**	**2011**	**% change**
Revenue	715	678	5
Operating costs	(348)	(370)	6
Depreciation and amortisation	(179)	(189)	5
Operating profit	**188**	**119**	**58**
Operating profit – constant currency	**188**	**120**	**57**
Operating profit by principal activities			
Metering	174	149	17
Grain LNG	86	66	30
Property	25	(2)	-
Sub-total operating profit	**285**	**213**	**34**
Corporate and other activities	(97)	(94)	(3)
Operating profit	**188**	**119**	**58**
Share of post-tax results of joint ventures and associates			
Total	**7**	**7**	**-**
Capital investment			
Metering	60	112	(46)
Grain LNG	37	86	(57)
Property	67	3	-
Other	117	74	58
Capital expenditure excluding joint ventures	**281**	**275**	**2**
Joint ventures (JVs)	13	135	(90)
Capital investment including investment in JVs	**294**	**410**	**(28)**

Operating profit from our other activities increased by 58% to £188m. This was driven by an increase in operating profit from our Grain LNG, Property and Metering businesses.

Metering operating profit was up £25m at £174m. Capital investment in this business was £60m. £12m of Metering operating profit and £12m of Metering capital investment related to the OnStream business which was sold in October 2011. In our National Grid Metering business, the contracts which governed the majority of our meter charges prior to February 2010 were not in place during 2011/12. Since April 2011, the affected customers have been charged for regulated services at the full tariff cap rate, resulting in an increase in revenues and operating profit.

Our Grain LNG business delivered an operating profit of £86m, up 30%. The phase III capacity expansion, which commenced commercial operations in December 2010, made an increased contribution to operating profit in 2011/12. As construction of phase III completed in 2010/11, capital investment in Grain LNG in 2011/12 was £49m lower than the previous year.

Our Property business delivered an operating profit of £25m, an increase of £27m over last year. This increase relates to lower environmental costs and an increased number of property disposals. Capital investment in the year mainly related to the purchase of our UK headquarters in Warwick.

Other capex increased by £43m to £117m, principally representing spend on US financial systems. We expect to allocate the majority of the capital cost of these systems among the operating companies through monthly service charges that include a return on investment to the service company.

Joint Ventures

Joint ventures in the Group consist principally of our interests in interconnector transmission electricity lines and gas pipelines. These include a 50% interest in the 1GW BritNed electricity interconnector between the Netherlands and England, a 26% interest in the Millennium natural gas pipeline in New York state and a 20% interest in the Iroquois gas pipeline between Long Island and the Canadian border.

National Grid’s share of post-tax results of joint ventures for the year was £7m. BritNed’s contribution to this was a loss of £2m due to the lack of arbitrage between UK and Netherlands power prices over the year.

Investment in joint ventures in 2011/12 was £13m compared to £135m last year. The reduction in investment is principally due to the completion of the BritNed joint venture with TenneT, which entered commercial operation on 1 April 2011. In addition capital investment in our Millennium Pipeline joint venture reduced in 2011/12.

We are further progressing our proposed electricity interconnector with Belgium in conjunction with Elia, with the tender process having now started. In addition we have started the seabed survey in relation to our joint development, with Statnett of an electricity interconnector to Norway.

We expect interconnection with Europe to be an ever more significant feature of the future energy landscape. A number of further projects are under active consideration both by National Grid and also by a number of other developers. These include potential further interconnectors to Denmark, Ireland, France, Norway, and Iceland.

PROVISIONAL FINANCIAL TIMETABLE

30 May 2012	Ordinary shares go ex-dividend
1 June 2012	Record date for 2011/12 final dividend
8 June 2012	Scrip reference price announced
12 June 2012	Annual Report & Accounts published
18 July 2012	Scrip election date for 2011/12 final dividend
30 July 2012	Interim management statement and Annual General Meeting, ICC, Birmingham
15 August 2012	2011/12 final dividend paid to qualifying ordinary shareholders
15 November 2012	2012/13 half year results
28 November 2012	Ordinary shares go ex-dividend
30 November 2012	Record date for the 2012/13 interim dividend
5 December 2012	Scrip reference price announced
14 December 2012	Scrip election date for the 2012/13 interim dividend
16 January 2013	2012/13 interim dividend paid to qualifying ordinary shareholders
January/February 2013	Interim management statement
May 2013	2012/13 preliminary results

CAUTIONARY STATEMENT

This announcement contains certain statements that are neither reported financial results nor other historical information. These statements are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements include information with respect to National Grid's financial condition, its results of operations and businesses, strategy, plans and objectives. Words such as 'anticipates', 'expects', 'should', 'intends', 'plans', 'believes', 'seeks', 'estimates', 'targets', 'may', 'will', 'continue', 'project' and similar expressions, as well as statements in the future tense, identify forward-looking statements. These forward-looking statements are not guarantees of National Grid's future performance and are subject to assumptions, risks and uncertainties that could cause actual future results to differ materially from those expressed in or implied by such forward-looking statements. Many of these assumptions, risks and uncertainties relate to factors that are beyond National Grid's ability to control or estimate precisely, such as changes in laws or regulations and decisions by governmental bodies or regulators (including the new RIIO approach in the UK); breaches of, or changes in, environmental, climate change and health and safety laws or regulations, including breaches arising from the potentially harmful nature of its activities; network failure or interruption, the inability to carry out critical non network operations and damage to infrastructure, due to adverse weather conditions including the result of climate change or due to unauthorised access to or deliberate breaches of our IT systems or otherwise; performance against regulatory targets and standards and against National Grid's peers with the aim of delivering stakeholder expectations regarding costs and efficiency savings, including those related to investment programmes, restructuring and internal transformation projects; and customers and counterparties failing to perform their obligations to the Company. Other factors that could cause actual results to differ materially from those described in this announcement include fluctuations in exchange rates, interest rates and commodity price indices; restrictions in National Grid's borrowing and debt arrangements, funding costs and access to financing; regulatory requirements for the Company to maintain financial resources in certain parts of its business and restrictions on some subsidiaries' transactions, such as paying dividends, lending or levying charges; inflation; the funding requirements of its pension schemes and other post-retirement benefit schemes; the loss of key personnel or the ability to attract, train or retain qualified personnel and any disputes arising with its employees or the breach of laws or regulations by its employees; and incorrect or unforeseen assumptions or conclusions (including financial and tax impacts and other unanticipated effects) relating to business development activity, including assumptions in connection with joint ventures. For a more detailed description of some of these assumptions, risks and uncertainties, together with any other risk factors, please see National Grid's filings with and submissions to the US Securities and Exchange Commission (the 'SEC') (and in particular the 'Risk factors' and 'Operating and Financial Review' sections in our most recent Annual Report on Form 20-F). The effects of these factors are difficult to predict. New factors emerge from time to time and National Grid cannot assess the potential impact of any such factor on its activities or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. Except as may be required by law or regulation, National Grid undertakes no obligation to update any of its forward-looking statements, which speak only as of the date of this announcement. The content of any website references herein do not form part of this announcement.

METRIC DEFINITIONS

The financial metrics we have reported today are designed to give greater transparency on National Grid's relative performance and our performance against regulatory contracts.

RoE Calculation

The group return on equity (RoE) calculation provides a measure of the performance of the whole group compared to the amounts invested by the group in assets attributable to equity shareholders.

The Group's return on equity measure is calculated using the group capital employed in accordance with the definition used in the RoCE measures adjusted for group net debt and goodwill.

This is a post-tax IFRS metric

Calculation: Adjusted net income divided by equity investment in assets

- Adjusted operating profit calculated as IFRS business performance operating profit adjusted according to the adjustments in the RoCE calculation calculated on a pre-tax basis
- Adjusted net income calculated as adjusted operating profit less group interest (excluding adjustments for interest on pensions, capitalised interest or release of provisions) less group taxation charge (adjusted for taxation on adjustments to operating profit and interest)
- Equity investment in assets is calculated as the total opening UK regulatory asset value excluding logged up spend and work in progress, the total opening US rate base plus goodwill plus opening net book value of joint ventures and non-regulated businesses; minus net debt as reported under IFRS

A detailed breakdown of the Group RoE calculation is shown below.

£m	2011/12	2010/11	2009/10
IFRS EBITDA	**4,762**	**4,845**	**4,309**
Timing adjustment	(18)	(277)	163
Regulatory adjustments (per RoCE calc)	(1,002)	(965)	(1,015)
Adjusted group interest charge	(1,042)	(1,150)	(968)
Storm cost adjustment*	116	-	-
Depreciation on non-regulated businesses	(179)	(189)	(173)
Adjusted operating profit	**2,637**	2,264	2,316
Share of post tax results of joint ventures	7	7	8
Group tax charge	(755)	(722)	(553)
Tax impact of adjustments	14	100	(74)
Adjusted net income	**1,903**	**1,649**	**1,697**
Opening Regulatory Assets	29,272	27,727	26,506
Opening NBV of non-regulated businesses	1,205	1,110	885
Joint Ventures	356	250	168
Opening Goodwill	4,776	5,102	5,391
Total Assets	**35,609**	**34,189**	**32,950**
Net Debt	(18,731)	(18,925)**	(19,459)**
Equity Investment in assets	**16,878**	**15,264**	**13,491**
Group Return on equity	**11.3%**	**10.8%**	**12.6%**

* Impact of two major US storms removed from the calculation as presented. Including storm costs, 2011/12 Group RoE was 10.9%
** £3,214m adjustment made to reflect rights issue proceeds in June 2010

Return on Capital Employed (RoCE)

In November 2011 we introduced a measure of **return on capital employed** ("RoCE") giving a better comparison between our UK and US businesses.

The RoCE is calculated using the assumption that the businesses are financed in line with the regulatory adjudicated capital structure.

This is a post-tax IFRS metric

Calculation: Adjusted profit after tax divided by rate base:

- Adjusted profit before tax is calculated as IFRS operating profit as reported on a business performance basis and excluding the impact of in year-timing.
- Adjusted profit before tax is also adjusted for regulatory depreciation, elements of regulatory pensions funding; capitalisation of gas distribution mains replacement (repex) in the UK; long run inflation of 3% on the UK regulated asset base; and UK regulatory deferred taxation treatment.
- The adjusted profit after tax is calculated by applying the headline rate of US corporation tax (combined state and federal taxes) and UK corporation tax to the adjusted profit before tax.
- Rate base is opening rate base or regulatory asset value excluding logged up spend and work in progress.

US Regulated Return on Equity (nominal)

US Regulated Return on Equity is a measure of how a business is performing operationally against the assumptions used by the regulator.

This US operational return measure is calculated using the assumption that the businesses are financed in line with the regulatory adjudicated capital structure.

This is a post-tax US GAAP metric as calculated annually (calendar year to 31 December).

Calculation: Regulated net income divided by equity rate base:

- Regulated net income calculated as US GAAP operating profit less interest on the adjudicated debt portion of the rate base (calculated at the actual rate on long term debt, adjusted where the proportion of long term debt in the capital structure is materially different from the assumed regulatory proportion) less tax at the adjudicated rate
- Regulated net income is adjusted for earned savings in New York and Narragansett Electric and certain material specified items.
- Equity rate base is the average rate base for the calendar year as reported to our regulators or, where a reported rate base is not available, an estimate based on rate base calculations used in previous rate filings multiplied by the adjudicated equity portion in the regulatory capital structure

UK Operational Return (real) (also known as Vanilla Return)

UK **operational return** is a measure of how a business is performing operationally against the assumptions used by the regulator.

These returns are calculated using the assumption that the businesses are financed in line with the regulatory adjudicated capital structure and at the assumed cost of debt.

This metric is an adjusted IFRS measure comparable to the “vanilla return” used by Ofgem.

Calculation: IFRS adjusted operating profit minus current tax, divided by regulatory asset value.

- IFRS adjusted operating profit is as reported on a business performance basis, adjusted for: impacts of timing (“k”), regulatory depreciation; capitalisation of gas distribution mains replacement (repex); and elements of regulatory pensions funding.
- Current tax is the tax charge as reported on a regulatory basis.
- Regulatory asset value is total UK regulatory asset value excluding logged up spend and work in progress

Interest Cover

This is an adjusted IFRS metric and reflects the calculation used by our credit rating agencies. It is used as an indicator of balance sheet efficiency.

Calculation: Adjusted funds from operations divided by adjusted interest expense.

Efficiency Metric

Calculation: Adjusted regulated controllable costs divided by asset base.

- Regulated controllable costs excluding bad debts.
- Asset base is the estimated mid-year UK regulatory asset value excluding logged up spend and work in progress and US rate base.

Consolidated income statement

for the years ended 31 March

	Notes	2012 £m	2011 £m
Revenue	2(a)	**13,832**	14,343
Operating costs		**(10,293)**	(10,598)
Operating profit			
Before exceptional items, remeasurements and stranded cost recoveries	2(b)	**3,495**	3,600
Exceptional items, remeasurements and stranded cost recoveries	3	**44**	145
Total operating profit	2(b)	**3,539**	3,745
Interest income and similar income			
Before exceptional items	4	**1,301**	1,281
Exceptional items	3	**-**	43
Total interest income and similar income	4	**1,301**	1,324
Interest expense and other finance costs			
Before exceptional items and remeasurements	4	**(2,218)**	(2,415)
Exceptional items and remeasurements	3	**(70)**	(37)
Total interest expense and other finance costs	4	**(2,288)**	(2,452)
Share of post-tax results of joint ventures and associates		**7**	7
Profit before tax			
Before exceptional items, remeasurements and stranded cost recoveries	2(b)	**2,585**	2,473
Exceptional items, remeasurements and stranded cost recoveries	3	**(26)**	151
Total profit before tax	2(b)	**2,559**	2,624
Taxation			
Before exceptional items, remeasurements and stranded cost recoveries	5	**(755)**	(722)
Exceptional items, remeasurements and stranded cost recoveries	3	**234**	261
Total taxation	5	**(521)**	(461)
Profit after tax			
Before exceptional items, remeasurements and stranded cost recoveries		**1,830**	1,751
Exceptional items, remeasurements and stranded cost recoveries	3	**208**	412
Profit for the year		**2,038**	2,163
Attributable to:			
Equity shareholders of the parent		**2,036**	2,159
Non-controlling interests		**2**	4
		2,038	2,163
Earnings per share*			
Basic	6(a)	**57.1p**	62.9p
Diluted	6(b)	**56.8p**	62.5p

* Comparative amounts have been restated to reflect the impact of additional shares issued as scrip dividends

Consolidated statement of comprehensive income
for the years ended 31 March

	2012 £m	2011 £m
Profit for the year	**2,038**	2,163
Other comprehensive (loss)/income:		
Exchange adjustments	**27**	(95)
Actuarial net (losses)/gains	**(1,325)**	571
Deferred tax on actuarial net gains and losses	**403**	(181)
Net (losses)/gains on cash flow hedges	**(18)**	7
Transferred to profit or loss on cash flow hedges	**19**	(7)
Deferred tax on cash flow hedges	**2**	(2)
Net gains on available-for-sale investments	**16**	16
Transferred to profit or loss on sale of available-for-sale investments	**(9)**	(3)
Deferred tax on available-for-sale investments	**(2)**	(1)
Share of post-tax other comprehensive loss of joint ventures	**-**	(4)
Other comprehensive (loss)/income for the year, net of tax	**(887)**	301
Total comprehensive income for the year	**1,151**	2,464
Total comprehensive income attributable to:		
Equity shareholders of the parent	**1,149**	2,460
Non-controlling interests	**2**	4
	1,151	2,464

Consolidated balance sheet

as at 31 March

	Notes	2012 £m	2011 £m
Non-current assets			
Goodwill		**4,776**	4,776
Other intangible assets		**546**	501
Property, plant and equipment		**33,701**	31,956
Other non-current assets		**95**	135
Pension assets		**155**	556
Financial and other investments		**592**	593
Derivative financial assets	9	**1,819**	1,270
Total non-current assets		**41,684**	39,787
Current assets			
Inventories and current intangible assets		**376**	320
Trade and other receivables		**1,971**	2,212
Financial and other investments	9	**2,391**	2,939
Derivative financial assets	9	**317**	468
Cash and cash equivalents	9	**332**	384
Total current assets		**5,387**	6,323
Assets of businesses held for sale	11	**264**	290
Total assets		**47,335**	46,400
Current liabilities			
Borrowings	9	**(2,492)**	(2,952)
Derivative financial liabilities	9	**(162)**	(190)
Trade and other payables		**(2,685)**	(2,828)
Current tax liabilities		**(383)**	(503)
Provisions		**(282)**	(353)
Total current liabilities		**(6,004)**	(6,826)
Non-current liabilities			
Borrowings	9	**(20,533)**	(20,246)
Derivative financial liabilities	9	**(1,269)**	(404)
Other non-current liabilities		**(1,921)**	(1,944)
Deferred tax liabilities		**(3,738)**	(3,766)
Pensions and other post-retirement benefit obligations		**(3,088)**	(2,574)
Provisions		**(1,449)**	(1,461)
Total non-current liabilities		**(31,998)**	(30,395)
Liabilities of businesses held for sale	11	**(87)**	(110)
Total liabilities		**(38,089)**	(37,331)
Net assets		**9,246**	9,069
Equity			
Called up share capital		**422**	416
Share premium account		**1,355**	1,361
Retained earnings		**12,297**	12,153
Other equity reserves		**(4,835)**	(4,870)
Shareholders' equity		**9,239**	9,060
Non-controlling interests		**7**	9
Total equity		**9,246**	9,069

Consolidated statement of changes in equity
for the years ended 31 March

	Note	Called up share capital £m	Share premium account £m	Retained earnings £m	Other equity reserves £m	Total share-holders' equity £m	Non-controlling interests £m	Total equity £m
At 1 April 2010		298	1,366	7,316	(4,781)	4,199	12	4,211
Total comprehensive income/(loss)		-	-	2,549	(89)	2,460	4	2,464
Rights issue		113	-	-	3,101	3,214	-	3,214
Transfer between reserves		-	-	3,101	(3,101)	-	-	-
Equity dividends	7	-	-	(1,064)	-	(1,064)	-	(1,064)
Scrip dividend related share issue	7	5	(5)	206	-	206	-	206
Issue of treasury shares		-	-	18	-	18	-	18
Purchase of own shares		-	-	(3)	-	(3)	-	(3)
Other movements in non-controlling interests		-	-	-	-	-	(7)	(7)
Share-based payment		-	-	25	-	25	-	25
Tax on share-based payment		-	-	5	-	5	-	5
At 31 March 2011		416	1,361	12,153	(4,870)	9,060	9	9,069
Total comprehensive income		-	-	1,114	35	1,149	2	1,151
Equity dividends	7	-	-	(1,319)	-	(1,319)	-	(1,319)
Scrip dividend related share issue	7	6	(6)	313	-	313	-	313
Issue of treasury shares		-	-	13	-	13	-	13
Purchase of own shares		-	-	(4)	-	(4)	-	(4)
Other movements in non-controlling interests		-	-	-	-	-	(4)	(4)
Share-based payment		-	-	24	-	24	-	24
Tax on share-based payment		-	-	3	-	3	-	3
At 31 March 2012		**422**	**1,355**	**12,297**	**(4,835)**	**9,239**	**7**	**9,246**

Consolidated cash flow statement

for the years ended 31 March

	Notes	2012 £m	2011 £m
Cash flows from operating activities			
Total operating profit	2(b)	**3,539**	3,745
Adjustments for:			
Exceptional items, remeasurements and stranded cost recoveries	3	**(44)**	(145)
Depreciation, amortisation and impairment		**1,282**	1,245
Share-based payment charge		**24**	25
Changes in working capital		**146**	185
Changes in provisions		**(116)**	(93)
Changes in pensions and other post-retirement benefit obligations		**(386)**	(304)
Cash flows relating to exceptional items		**(205)**	(147)
Cash flows relating to stranded cost recoveries		**247**	343
Cash generated from operations		**4,487**	4,854
Tax (paid)/received		**(259)**	4
Net cash inflow from operating activities		**4,228**	4,858
Cash flows from investing activities			
Acquisition of investments		**(13)**	(135)
Net proceeds from sale of investments in subsidiaries		**365**	11
Purchases of intangible assets		**(203)**	(176)
Purchases of property, plant and equipment		**(3,147)**	(2,958)
Disposals of property, plant and equipment		**24**	26
Dividends received from joint ventures		**26**	9
Interest received		**24**	26
Net movements in short-term financial investments		**553**	(1,577)
Net cash flow used in investing activities		**(2,371)**	(4,774)
Cash flows from financing activities			
Proceeds of rights issue		**-**	3,214
Proceeds from issue of treasury shares		**13**	18
Purchase of own shares		**(4)**	(3)
Proceeds from loans received		**1,809**	767
Repayments of loans		**(1,914)**	(2,878)
Net movements in short-term borrowings and derivatives		**(49)**	348
Interest paid		**(749)**	(965)
Exceptional finance costs on the redemption of debt		**-**	(73)
Dividends paid to shareholders		**(1,006)**	(858)
Net cash flow used in financing activities		**(1,900)**	(430)
Net decrease in cash and cash equivalents	8	**(43)**	(346)
Exchange movements		**-**	(3)
Net cash and cash equivalents at start of year		**342**	691
Net cash and cash equivalents at end of year (i)		**299**	342

(i) Net of bank overdrafts of £33m (2011: £42m).

Notes

1. Basis of preparation and new accounting standards, interpretations and amendments

The full year financial information contained in this announcement, which does not constitute statutory accounts as defined in Section 434 of the Companies Act 2006, has been derived from the statutory accounts for the year ended 31 March 2012, which will be filed with the Registrar of Companies in due course. Statutory accounts for the year ended 31 March 2011 have been filed with the Registrar of Companies. The auditors' report on each of these statutory accounts was unqualified and did not contain a statement under Section 498 of the Companies Act 2006.

The full year financial information has been prepared in accordance with the accounting policies applicable for the year ended 31 March 2012 and consistent with those applied in the preparation of our accounts for the year ended 31 March 2011. During the year ended 31 March 2012, the Company has not adopted any new International Financial Reporting Standards (IFRS), International Accounting Standards (IAS) or amendments issued by the International Accounting Standards Board (IASB) and interpretations issued by the IFRS Interpretations Committee, which have had a material impact on the Company's consolidated financial statements.

Date of approval
This announcement was approved by the Board of Directors on 16 May 2012.

2. Segmental analysis

The Board of Directors is National Grid's chief operating decision making body (as defined by IFRS 8 on operating segments). The segmental analysis is based on the information the Board of Directors uses internally for the purposes of evaluating the performance of operating segments and determining resource allocation between segments. The performance of operating segments is assessed principally on the basis of operating profit before exceptional items, remeasurements and stranded cost recoveries. The following table describes the main activities for each operating segment:

UK Transmission	High voltage electricity transmission networks, the gas transmission network in Great Britain, UK liquefied natural gas (LNG) storage activities and the French electricity interconnector.
UK Gas Distribution	Four of the eight regional networks of Great Britain's gas distribution system.
US Regulated	Gas distribution networks, electricity distribution networks and high voltage electricity transmission networks in New York and New England and electricity generation facilities in New York.

Other activities primarily relate to non-regulated businesses and other commercial operations not included within the above segments, including: UK-based gas and electricity metering activities (including OnStream up to the date it was sold on 24 October 2011); UK property management; a UK LNG import terminal; other LNG operations; US unregulated transmission pipelines; US gas fields (related to Seneca-Upshur up to the date it was sold on 3 October 2011); together with corporate activities.

Sales between operating segments are priced having regard to the regulatory and legal requirements to which the businesses are subject. The analysis of revenue by geographical area is on the basis of destination. There are no material sales between the UK and US geographical areas.

As a consequence of the introduction of a new operating model, which took effect on 4 April 2011, there has been a change to the reported segments: the US Transmission, US Gas Distribution and US Electricity Distribution & Generation segments which were presented as separate segments in prior periods have been combined and are reported as a single 'US Regulated' segment.

(a) Revenue

	2012	2011
	£m	£m
Operating segments		
UK Transmission	**3,804**	3,484
UK Gas Distribution	**1,605**	1,524
US Regulated	**7,795**	8,746
Other activities	**715**	678
Sales between segments	**(87)**	(89)
	13,832	14,343
Total excluding stranded cost recoveries	**13,553**	13,988
Stranded cost recoveries	**279**	355
	13,832	14,343
Geographical areas		
UK	**6,000**	5,556
US	**7,832**	8,787
	13,832	14,343

2. Segmental analysis continued

(b) Operating profit

	Before exceptional items, remeasurements and stranded cost recoveries		After exceptional items, remeasurements and stranded cost recoveries	
	2012	2011	**2012**	2011
	£m	£m	**£m**	£m
Operating segments				
UK Transmission	**1,354**	1,363	**1,354**	1,293
UK Gas Distribution	**763**	711	**739**	671
US Regulated	**1,190**	1,407	**1,154**	1,704
Other activities	**188**	119	**292**	77
	3,495	3,600	**3,539**	3,745
Geographical areas				
UK	**2,353**	2,226	**2,357**	2,055
US	**1,142**	1,374	**1,182**	1,690
	3,495	3,600	**3,539**	3,745
Reconciliation to profit before tax:				
Operating profit	**3,495**	3,600	**3,539**	3,745
Interest income and similar income	**1,301**	1,281	**1,301**	1,324
Interest expense and other finance costs	**(2,218)**	(2,415)	**(2,288)**	(2,452)
Share of post-tax results of joint ventures and associates	**7**	7	**7**	7
Profit before tax	**2,585**	2,473	**2,559**	2,624

3. Exceptional items, remeasurements and stranded cost recoveries

Exceptional items, remeasurements and stranded cost recoveries are items of income and expenditure that, in the judgment of management, should be disclosed separately on the basis that they are important to an understanding of our financial performance and significantly distort the comparability of financial performance between periods. Remeasurements comprise gains or losses recorded in the income statement arising from changes in the fair value of commodity contracts and of derivative financial instruments to the extent that hedge accounting is not achieved or is not effective. Stranded cost recoveries represent the recovery of historical generation-related costs in the US, related to generation assets that are no longer owned by National Grid. Such costs are being recovered from customers as permitted by regulatory agreements with almost all having been received by 31 March 2012.

	2012 £m	2011 £m
Included within operating profit:		
Exceptional items:		
Restructuring costs (1)	**(101)**	(89)
Environmental charges (2)	**(55)**	(128)
Net gain on disposal of businesses (3)	**97**	15
Impairment charges and related costs (4)	**(64)**	(133)
Other (5)	**1**	(15)
	(122)	(350)
Remeasurements – commodity contracts (6)	**(94)**	147
Stranded cost recoveries (7)	**260**	348
	44	145
Included within interest income and similar income:		
Exceptional items:		
Interest credit on tax settlement (8)	**-**	43
Included within finance costs:		
Exceptional items:		
Debt redemption costs (9)	**-**	(73)
Remeasurements:		
Net (losses)/gains on derivative financial instruments (10)	**(70)**	36
	(70)	(37)
Total included within profit before tax	**(26)**	151
Included within taxation:		
Exceptional credits arising on items not included in profit before tax:		
Deferred tax credit arising on the reduction in the UK tax rate (11)	**242**	226
Other (12)	**-**	59
Tax on exceptional items	**54**	79
Tax on remeasurements (6, 10)	**42**	36
Tax on stranded cost recoveries	**(104)**	(139)
	234	261
Total exceptional items, remeasurements and stranded cost recoveries after tax	**208**	412
Analysis of exceptional items, remeasurements and stranded cost recoveries after tax:		
Total exceptional items after tax	**174**	(16)
Total remeasurements after tax	**(122)**	219
Total stranded cost recoveries after tax	**156**	209
Total	**208**	412

3. Exceptional items, remeasurements and stranded cost recoveries continued

1) Restructuring costs for the year include: costs related to the restructuring of our US operations of £58m (2011: £10m) which includes a severance provision and a pension and other post-retirement benefits curtailment loss (2011: gain); transformation related initiatives of £54m (2011: £103m); and a credit of £11m (2011: £39m) for the release of restructuring provisions in the UK recognised in prior years. Restructuring costs in 2011 also included a charge of £15m related to the integration of KeySpan.

2) Environmental charges include £55m (2011: £58m) and £nil (2011: £70m) related to specific exposures in the US and UK respectively. Costs incurred with respect to US environmental provisions are substantially recoverable from customers.

3) During the year we recognised a gain on disposal of £56m for the sale of Seneca-Upshur our oil and gas exploration business in West Virginia and Pennsylvania; a gain of £16m for the sale of OnStream our non-regulated metering business in the UK; and gains of £25m in relation to disposals of businesses in prior years representing the release of various unutilised provisions. During the year ended 31 March 2011, we sold three subsidiaries and an associate resulting in a gain of £15m.

4) The charge for the current year represents an impairment of £64m of intangibles (originally recognised on the acquisition of KeySpan) related to our Long Island Power Authority management services agreement contract, following the announcement on 15 December 2011 that the current contract would not be renewed after 31 December 2013. During the year ended 31 March 2011, impairment charges and related costs included a charge of £49m related to our investment in Blue-NG; an impairment charge of £34m against the goodwill related to our US companies in New Hampshire following our proposed sale of these businesses; and a charge of £50m related to our US generation assets for impairment and associated decommissioning.

5) Other exceptional charges for the year include an amortisation charge of £5m (2011: £7m) in relation to acquisition-related intangibles, offset by a release of £6m of unutilised provisions in our metering business originally recognised during the year ended 31 March 2010. The charge for the prior year included an £8m penalty levied by Ofgem on our UK Gas Distribution business.

6) Remeasurements – commodity contracts represent mark-to-market movements on certain physical and financial commodity contract obligations in the US. These contracts primarily relate to the forward purchase of energy for supply to customers, or to the economic hedging thereof, that are required to be measured at fair value and that do not qualify for hedge accounting. Under the existing rate plans in the US, commodity costs are recoverable from customers although the timing of recovery may differ from the pattern of costs incurred. These movements are comprised of those affecting operating profit which are based on the change in the commodity contract liability and those recorded in finance costs as a result of the time value of money.

7) Stranded cost recoveries include the recovery of some of our historical investments in generating plants that were divested as part of the restructuring and wholesale power deregulation process in New England and New York during the 1990s. The recovery of these stranded costs is now substantially completed and we do not expect to separately report income from stranded cost recoveries from 1 April 2012 onwards. Stranded cost recoveries on a pre-tax basis consist of revenue of £279m (2011: £355m) and operating costs of £19m (2011: £7m).

8) During the year ended 31 March 2011 we reached agreement with the US tax authorities on the settlement of pre-acquisition tax liabilities which resulted in the repayment of tax and interest accruing.

9) Debt redemption costs for the year ended 31 March 2011 represented costs arising from our debt repurchase programme following the rights issue on 14 June 2010.

10) Remeasurements – net gains and losses on derivative financial instruments comprise gains and losses arising on derivative financial instruments reported in the income statement. These exclude gains and losses for which hedge accounting has been effective, which have been recognised directly in other comprehensive income or which are offset by adjustments to the carrying value of debt. The tax credit in the year includes a credit of £1m (2011: £104m) in respect of prior years.

11) The exceptional tax credit arises from a reduction in the UK corporation tax rate from 26% to 24% (2011: from 28% to 26%) included in the Finance Bill 2012 and has statutory effect under the Provisional Collection of Taxes Act 1968 and applicable from 1 April 2012. This results in a reduction in deferred tax liabilities.

12) The exceptional tax credit for the year ended 31 March 2011 primarily arose from a settlement of pre-acquisition tax liabilities with the US tax authorities.

4. Finance income and costs

	2012 £m	2011 £m
Expected return on pension and other post-retirement benefit plan assets	**1,273**	1,256
Interest income on financial instruments	**28**	25
Interest income and similar income before exceptional items	**1,301**	1,281
Exceptional interest credit on tax settlement	**-**	43
Interest income and similar income	**1,301**	1,324
Interest on pension and other post-retirement benefit plan obligations	**(1,203)**	(1,231)
Interest expense on financial instruments	**(1,067)**	(1,185)
Unwinding of discounts on provisions	**(72)**	(128)
Less: interest capitalised	**124**	129
Interest expense and other finance costs before exceptional items and remeasurements	**(2,218)**	(2,415)
Exceptional debt redemption costs	**-**	(73)
Net (losses)/gains on derivative financial instruments included in remeasurements	**(70)**	36
Exceptional items and remeasurements included within interest expense	**(70)**	(37)
Interest expense and other finance costs	**(2,288)**	(2,452)
Net finance costs	**(987)**	(1,128)

5. Taxation

	2012 £m	2011 £m
Tax before exceptional items, remeasurements and stranded cost recoveries	**755**	722
Exceptional tax on items not included in profit before tax (see note 3)	**(242)**	(285)
Tax on other exceptional items, remeasurements and stranded cost recoveries	**8**	24
Tax on total exceptional items, remeasurements and stranded cost recoveries (see note 3)	**(234)**	(261)
Total tax charge	**521**	461

Taxation as a percentage of profit before tax	%	%
Before exceptional items, remeasurements and stranded cost recoveries	**29.2**	29.2
After exceptional items, remeasurements and stranded cost recoveries	**20.4**	17.6

The tax charge for the year can be analysed as follows:

	£m	£m
United Kingdom		
Corporation tax at 26% (2011: 28%)	**186**	168
Corporation tax adjustment in respect of prior years	**(5)**	(161)
Deferred tax	**12**	53
Deferred tax adjustment in respect of prior years	**(18)**	(43)
	175	17
Overseas		
Corporate tax	**98**	105
Corporate tax adjustment in respect of prior years	**(144)**	(2)
Deferred tax	**225**	393
Deferred tax adjustment in respect of prior years	**167**	(52)
	346	444
Total tax charge	**521**	461

Adjustments in respect of prior years include £nil for corporation tax (2011: £207m credit) and a £1m deferred tax credit (2011: £44m charge) that relate to exceptional items, remeasurements and stranded cost recoveries.

6. Earnings per share

Adjusted earnings per share, excluding exceptional items, remeasurements and stranded cost recoveries, are provided to reflect the business performance subtotals used by the Company. For further details of exceptional items, remeasurements and stranded cost recoveries, see note 3.

(a) Basic earnings per share

	2012 Earnings £m	**2012 Earnings per share pence**	2011 Earnings £m	2011* Earnings per share pence
Adjusted earnings	**1,828**	**51.3**	1,747	50.9
Exceptional items after tax	**174**	**4.9**	(16)	(0.5)
Remeasurements after tax	**(122)**	**(3.4)**	219	6.4
Stranded cost recoveries after tax	**156**	**4.3**	209	6.1
Earnings	**2,036**	**57.1**	2,159	62.9

	millions	millions
Weighted average number of shares – basic*	**3,565**	3,431

(b) Diluted earnings per share

	2012 Earnings £m	**2012 Earnings per share pence**	2011 Earnings £m	2011* Earnings per share pence
Adjusted diluted earnings	**1,828**	**51.0**	1,747	50.6
Exceptional items after tax	**174**	**4.9**	(16)	(0.5)
Remeasurements after tax	**(122)**	**(3.4)**	219	6.3
Stranded cost recoveries after tax	**156**	**4.3**	209	6.1
Diluted earnings	**2,036**	**56.8**	2,159	62.5

	millions	millions
Weighted average number of shares – diluted*	**3,584**	3,450

* Comparative amounts have been restated to reflect the impact of additional shares issued as scrip dividends

7. Dividends

The following table shows the actual dividends paid to equity shareholders:

	2012 pence per share	**2012 Total £m**	**2012 settled via scrip £m**	2011 pence per share	2011 Total £m	2011 settled via scrip £m
Interim - year ended 2012	**13.93**	**496**	**34**	-	-	-
Final - year ended 2011	**23.47**	**823**	**279**	-	-	-
Interim - year ended 2011	**-**	**-**	**-**	12.90	451	65
Final - year ended 2010	**-**	**-**	**-**	24.84	613	141
	37.40	**1,319**	**313**	37.74	1,064	206

The Directors are proposing a final dividend for 2012 of 25.35p per share that will absorb approximately £905m of shareholders' equity (assuming all amounts are settled in cash). It will be paid on 15 August 2012 to shareholders who are on the register of members at 1 June 2012 and a scrip dividend will be offered as an alternative, subject to shareholders' approval at the Annual General Meeting.

8. Reconciliation of net cash flow to movement in net debt

	2012 £m	2011 £m
Decrease in cash and cash equivalents	**(43)**	(346)
(Decrease)/increase in financial investments	**(553)**	1,577
Decrease in borrowings and related derivatives	**154**	1,763
Net interest paid on the components of net debt	**721**	1,011
Change in net debt resulting from cash flows	**279**	4,005
Changes in fair value of financial assets and liabilities and exchange movements	**(87)**	690
Net interest charge on the components of net debt	**(1,042)**	(1,228)
Reclassified as held for sale	**(2)**	9
Other non-cash movements	**(14)**	(68)
Movement in net debt (net of related derivative financial instruments) in the year	**(866)**	3,408
Net debt (net of related derivative financial instruments) at start of year	**(18,731)**	(22,139)
Net debt (net of related derivative financial instruments) at end of year	**(19,597)**	(18,731)

9. Net debt

	2012 £m	2011 £m
Cash and cash equivalents	**332**	384
Bank overdrafts	**(33)**	(42)
Net cash and cash equivalents	**299**	342
Financial investments	**2,391**	2,939
Borrowings (excluding bank overdrafts)	**(22,992)**	(23,156)
	(20,302)	(19,875)
Net debt related derivative financial assets	**2,136**	1,738
Net debt related derivative financial liabilities	**(1,431)**	(594)
Net debt (net of related derivative financial instruments)	**(19,597)**	(18,731)

10. Commitments and contingencies

	2012 £m	2011 £m
Future capital expenditure contracted for but not provided	**2,728**	1,614
Operating lease commitments	**706**	795
Energy purchase commitments (i)	**4,174**	3,543
Guarantees and letters of credit (a)	**1,344**	762

(i) Commodity contracts that do not meet the normal purchase, sale or usage criteria and hence are accounted for as derivative contracts are recorded at fair value and incorporated in other non-current assets, trade and other receivables, trade and other payables and other non-current liabilities. At 31 March 2012 these amounted to net liabilities of £189m (2011: £109m).

(a) Guarantees and letters of credit

	2012 £m	2011 £m
Guarantee of sublease for US property (expires 2040)	**304**	328
Letter of credit and guarantee of certain obligations of BritNed Interconnector (expired 2011)	**-**	36
Guarantees of certain obligations of Grain LNG Import Terminal (expire up to 2028)	**161**	139
Guarantee of certain obligations for construction of HVDC West Coast Link (expected expiry 2016)	**691**	-
Other guarantees and letters of credit (various expiry dates)	**188**	259
	1,344	762

(b) Litigation and claims

KeySpan class actions

As reported in our 2010/11 Annual Report and Accounts, two putative class actions were commenced in 2009 against KeySpan and Morgan Stanley, one in the federal court and one in a New York state court. The claims were based on allegations that the financial swap transaction between KeySpan and Morgan Stanley dated 18 January 2006 caused customers of Consolidated Edison, Inc. to overpay for electricity between May 2006 and February 2008. Both claims were dismissed – the first on 22 March 2011 and the second on appeal on 10 April 2012. On 6 January 2012, a third putative class action was commenced in the federal court on behalf of Niagara Mohawk Power Corporation customers on similar grounds and in respect of the same financial swap transaction which we also believe is without merit.

11. Businesses held for sale

During the year ended 31 March 2011, our EnergyNorth gas business and Granite State electricity business in New Hampshire were reclassified as businesses held for sale in the expectation that they would be disposed of during the year ended 31 March 2012. We are continuing to work with the New Hampshire Public Utility Commission to obtain regulatory approval to complete the disposals. We expect to receive these approvals and to be able to complete the disposals. We therefore continue to report the businesses as held for sale.

The results of these businesses have not been separately disclosed from those of continuing operations as they do not constitute a separate major line of business or geographical area of National Grid's operations.

12. Exchange rates

The consolidated results are affected by the exchange rates used to translate the results of our US operations and US dollar transactions. The US dollar to pound sterling exchange rates used were:

	2012	2011
Closing rate applied at year end	**1.60**	1.61
Average rate applied for the year	**1.60**	1.57

13. Related party transactions

The following significant transactions with related parties were in the normal course of business; amounts receivable from and payable to related parties are due on normal commercial terms:

	2012 £m	2011 £m
Sales: Services and goods supplied to a pension plan and joint ventures	**10**	11
Purchases: Services and goods received from joint ventures (i)	**95**	84
Interest income: Interest receivable on loans with joint ventures	**-**	2
Receivable from a pension plan and joint ventures	**2**	2
Payable to joint ventures	**6**	8
Dividends received from joint ventures (ii)	**26**	9

(i) During the year the Company received services and goods from a number of joint ventures, including Iroquois Gas Transmission System, L.P. of £39m (2011: £40m) and Millennium Pipeline Company, LLC of £32m (2011: £28m) for the transportation of gas in the US.

(ii) Dividends were received from Iroquois Gas Transmission System, L.P. of £17m (2011: £9m); and Millennium Pipeline Company, LLC of £9m (2011: £nil).

For the year ended 31 March 2011, following a decision in August 2010 to cease investing in Blue-NG (a joint venture), an impairment charge was recorded against the carrying value of the investment, together with provision against recovery of loans from National Grid to Blue-NG of £30m and associated interest receivable.

Selection of Proxy Group Utilities

Line No	Company name	Ticker	VL Report Date	Pays Constant or Increasing Dividend?	S&P Corporate Credit rating	2011 Revenues > $1 billion	Credit Rating Within 1 Notch of NiMo?	Total 2011 revenues (millions)	Merger/Spin-off Activity?	Include in Comparables Group?
1	**Allete**	ALE	6/22/2012	YES	BBB+		**YES**	**$928**		
2	**Alliant Energy**	LNT	6/22/2012	YES	BBB+	**YES**	**YES**	**$3,665**		**YES**
3	**Amer.Elec. Power**	AEP	6/22/2012	YES	BBB	**YES**		**$15,116**		
4	**Ameren Corp.**	AEE	6/22/2012	YES	BBB-	**YES**		**$7,531**		
5	**Avista Corp.**	AVA	8/3/2012	YES	BBB	**YES**		**$1,620**		
6	**Black Hills**	BKH	8/3/2012	YES	BBB-	**YES**		**$1,272**		
7	**CenterPoint Energy**	CNP	6/22/2012	YES	BBB+	**YES**	**YES**	**$8,450**		**YES**
8	**CH Energy Group**	CHG	5/25/2012	YES	A		**YES**	**$985**	**YES**	
9	**Cleco Corp.**	CNL	6/22/2012	YES	BBB	**YES**		**$1,117**		
10	**CMS Energy Corp.**	CMS	6/22/2012	YES	BBB-	**YES**		**$6,503**		
11	**Consol. Edison**	ED	5/25/2012	YES	A-	**YES**	**YES**	**$12,938**		**YES**
12	**Dominion Resources**	D	5/25/2012	YES	A-	**YES**	**YES**	**$14,379**		**YES**
13	**DTE Energy**	DTE	6/22/2012	YES	BBB+	**YES**	**YES**	**$8,897**		**YES**
14	**Duke Energy**	DUK	5/25/2012	YES	A-	**YES**	**YES**	**$14,529**	**YES**	
15	**Edison International/SCE**	EIX	8/3/2012	YES	BBB-	**YES**		**$12,760**		
16	**El Paso Electric**	EE	8/3/2012	NO	BBB			**$918**		
17	**Empire Dist. Elec.**	EDE	6/22/2012	NO	BBB-			**$577**		
18	**Entergy Corp**	ETR	6/22/2012	YES	BBB	**YES**		**$11,229**	**YES**	
19	**Exelon Corp.**	EXC	5/25/2012	YES	BBB	**YES**		**$18,924**	**YES**	
20	**FirstEnergy Corp.**	FE	5/25/2012	YES	BBB-	**YES**		**$16,258**		
21	**Great Plains Energy**	GXP	6/22/2012	YES	BBB	**YES**		**$2,318**		
22	**Hawaiian Elec.**	HE	8/3/2012	YES	BBB-	**YES**		**$3,242**		
23	**IDACORP, Inc.**	IDA	8/3/2012	YES	BBB	**YES**		**$1,027**		
24	**Integrys Energy**	TEG	6/22/2012	YES	A-	**YES**	**YES**	**$4,709**		**YES**
25	**ITC Holdings**	ITC	6/22/2012	YES	BBB+		**YES**	**$757**	**YES**	
26	**MGE Energy**	MGEE	6/22/2012	YES	AA-			**$546**		
27	**NextEra**	NEE	5/25/2012	YES	A-	**YES**	**YES**	**$15,341**		**YES**
28	**Northeast Utilities**	NU	5/25/2012	YES	A-	**YES**	**YES**	**$4,466**	**YES**	
29	**Northwestern Corp.**	NEW	8/3/2012	YES	BBB	**YES**		**$1,117**		
30	**NV Energy**	NVE	8/3/2012	YES	BB+	**YES**		**$2,943**		
31	**OGE Energy**	OGE	6/22/2012	YES	BBB+	**YES**	**YES**	**$3,916**		**YES**
32	**Otter Tail Corp.**	OTTR	6/22/2012	YES	BBB-	**YES**		**$1,078**		
33	**Pepco Holdings**	POM	5/25/2012	YES	BBB+	**YES**	**YES**	**$5,920**		**YES**
34	**PG&E Corp.**	PCG	8/3/2012	YES	BBB	**YES**		**$14,956**		

Selection of Proxy Group Utilities

Line No	Company name	Ticker	VL Report Date	Pays Constant or Increasing Dividend?	S&P Corporate Credit rating	2011 Revenues > $1 billion	Credit Rating Within 1 Notch of NiMo?	Total 2011 revenues (millions)	Merger/Spin-off Activity?	Include in Comparables Group?
35	**Pinnacle West Capital**	PNW	8/3/2012	YES	BBB	**YES**		**$3,241**		
36	**PNM Resources**	PNM	8/3/2012	YES	BBB-	**YES**		**$1,701**		
37	**Portland General**	POR	8/3/2012	YES	BBB	**YES**		**$1,813**		
38	**PPL Corp.**	PPL	5/25/2012	YES	BBB	**YES**		**$12,737**		
39	**Public Serv. Enterprise**	PEG	5/25/2012	YES	BBB	**YES**		**$11,343**		
40	**SCANA Corp**	SCG	5/25/2012	YES	BBB+	**YES**	**YES**	**$4,409**		**YES**
41	**Sempra Energy**	SRE	8/3/2012	YES	BBB+	**YES**	**YES**	**$10,036**		**YES**
42	**Southern Co.**	SO	5/25/2012	YES	A	**YES**	**YES**	**$17,657**		**YES**
43	**TECO Energy**	TE	5/25/2012	YES	BBB+	**YES**	**YES**	**$3,343**		**YES**
44	**UIL Holdings**	UIL	5/25/2012	YES	BBB	**YES**		**$1,570**		
45	**UNS Energy**	UNS	8/3/2012	YES	BB+	**YES**		**$1,510**		
46	**Vectren Corp.**	VVC	6/22/2012	YES	A-	**YES**	**YES**	**$2,325**		**YES**
47	**Westar Energy**	WR	6/22/2012	YES	BBB	**YES**		**$2,171**		
48	**Wisconsin Energy**	WEC	6/22/2012	YES	A-	**YES**	**YES**	**$4,486**		**YES**
49	**Xcel Energy**	XEL	8/3/2012	YES	A-	**YES**	**YES**	**$10,655**		**YES**

Number of Firms **16**

"Sustainable" or "br+sv" Growth Rate Calculation

Line No.	Company	Symbol	Earnings Per Share (EPS)	Dividend Per Share (DPS)	Book Value Per Share (BV)	Internal Growth (br)	Average Market Price Per Share (MV)	MV/BV	2011 Common Shares Outstanding	2015-17 Common Shares Outstanding	AARG 2011-2015/17	External Growth (sv)	br+sv
				[1]		[2]	[3]	[4]	[5]		[6]	[7]	[8]
1	**Alliant Energy**	**LNT**	$ 3.02	$ 1.90	$ 29.65	3.84%	$ 43.62	1.47	111.02	116.00	0.88%	0.42%	**4.26%**
2	**CenterPoint Energy**	**CNP**	$ 1.27	$ 0.83	$ 10.74	4.17%	$ 19.71	1.84	426.00	431.00	0.23%	0.20%	**4.37%**
3	**Consol. Edison**	**ED**	$ 3.84	$ 2.44	$ 42.13	3.36%	$ 59.65	1.42	292.90	293.00	0.01%	0.00%	**3.36%**
4	**Dominion Resources**	**D**	$ 3.30	$ 2.23	$ 22.93	4.79%	$ 51.52	2.25	570.00	595.00	0.86%	1.08%	**5.87%**
5	**DTE Energy**	**DTE**	$ 3.94	$ 2.49	$ 44.55	3.31%	$ 55.87	1.25	169.25	181.00	1.35%	0.34%	**3.66%**
6	**Integrys Energy**	**TEG**	$ 3.39	$ 2.75	$ 40.07	1.43%	$ 54.16	1.35	77.91	77.90	0.00%	0.00%	**1.43%**
7	**NextEra**	**NEE**	$ 5.16	$ 2.60	$ 41.22	6.47%	$ 63.68	1.54	416.00	430.00	0.66%	0.36%	**6.83%**
8	**OGE Energy**	**OGE**	$ 3.77	$ 1.67	$ 30.39	7.23%	$ 52.29	1.72	98.10	101.00	0.58%	0.42%	**7.65%**
9	**Pepco Holdings**	**POM**	$ 1.36	$ 1.11	$ 19.98	1.17%	$ 19.02	0.95	227.50	255.00	2.31%	-0.11%	**1.06%**
10	**SCANA Corp**	**SCG**	$ 3.27	$ 2.02	$ 33.71	3.86%	$ 45.80	1.36	130.00	160.00	4.24%	1.52%	**5.38%**
11	**Sempra Energy**	**SRE**	$ 4.79	$ 2.37	$ 45.05	5.45%	$ 62.87	1.40	239.93	246.00	0.50%	0.20%	**5.65%**
12	**Southern Co.**	**SO**	$ 2.78	$ 2.02	$ 22.57	3.46%	$ 45.04	2.00	865.10	940.00	1.67%	1.67%	**5.12%**
13	**TECO Energy**	**TE**	$ 1.44	$ 0.94	$ 11.55	4.35%	$ 17.41	1.51	215.80	221.00	0.48%	0.24%	**4.59%**
14	**Vectren Corp.**	**VVC**	$ 2.03	$ 1.47	$ 19.18	2.84%	$ 29.05	1.51	81.90	88.00	1.45%	0.74%	**3.59%**
15	**Wisconsin Energy**	**WEC**	$ 2.39	$ 1.35	$ 18.47	5.83%	$ 36.38	1.97	230.50	223.00	-0.66%	-0.64%	**5.19%**
16	**Xcel Energy**	**XEL**	$ 1.91	$ 1.15	$ 19.11	4.06%	$ 27.15	1.42	486.49	515.00	1.15%	0.48%	**4.54%**

Notes:

[1] Source: Value Line Investment Survey (Arithmetic Average of 2011, 2012, and 2015/17 Forecast Values)
[2] Equals (EPS-DPS)/BV
[3] Equals arithmetic average of 6-month monthly high and low stock prices ending July 31, 2012
[4] Equals MV/BV
[5] Source: Value Line Investment Survey (Common Shares Outstanding in Millions Adjusted for Split)
[6] Equals annual growth of common shares outstanding in [5]
[7] Equals ([4]-1)*[6]
[8] Equals [2]+[7]

I/B/E/S Earnings Growth Forecasts
July 31, 2012

Line No.	Company Name	Ticker	I/B/E/S Consensus long-term earnings forecast, as of July 31, 2012
1	**Alliant Energy**	**LNT**	6.30%
2	**CenterPoint Energy**	**CNP**	4.90%
3	**Consol. Edison**	**ED**	3.02%
4	**Dominion Resources**	**D**	5.00%
5	**DTE Energy**	**DTE**	4.59%
6	**Integrys Energy**	**TEG**	5.00%
7	**NextEra**	**NEE**	5.23%
8	**OGE Energy**	**OGE**	5.00%
9	**Pepco Holdings**	**POM**	4.75%
10	**SCANA Corp**	**SCG**	6.13%
11	**Sempra Energy**	**SRE**	7.00%
12	**Southern Co.**	**SO**	5.38%
13	**TECO Energy**	**TE**	2.66%
14	**Vectren Corp.**	**VVC**	5.00%
15	**Wisconsin Energy**	**WEC**	6.05%
16	**Xcel Energy**	**XEL**	5.08%

Source: Yahoo! Finance, Accessed 08/13/2012.

FERC Monthly Average Stock Prices, Low, High Dividend Yields

Company	Stock Price	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Avg.
Alliant Energy	High	$42.58	$42.83	$44.81	$44.90	$45.37	$47.25	
	Low	$41.81	$41.47	$41.49	$43.02	$42.99	$44.97	
	(High+Low)/2	$42.20	$42.15	$43.15	$43.96	$44.18	$46.11	**$43.62**
	Annual Dividend	$1.7000	$1.7250	$1.7250	$1.7250	$1.7500	$1.7500	
	Dividend Yield (Low)	3.99%	4.03%	3.85%	3.84%	3.86%	3.70%	**3.88%**
	Dividend Yield (High)	4.07%	4.16%	4.16%	4.01%	4.07%	3.89%	**4.06%**
	Dividend Yield (Average)	4.03%	4.09%	4.00%	3.92%	3.96%	3.80%	**3.97%**
CenterPoint Energy	High	$19.29	$19.52	$20.01	$20.24	$20.71	$21.19	
	Low	$18.20	$18.75	$18.87	$19.52	$19.78	$20.46	
	(High+Low)/2	$18.75	$19.14	$19.44	$19.88	$20.25	$20.83	**$19.71**
	Annual Dividend	$0.7900	$0.7900	$0.7950	$0.7950	$0.8000	$0.8000	
	Dividend Yield (Low)	4.10%	4.05%	3.97%	3.93%	3.86%	3.78%	**3.95%**
	Dividend Yield (High)	4.34%	4.21%	4.21%	4.07%	4.04%	3.91%	**4.13%**
	Dividend Yield (Average)	4.21%	4.13%	4.09%	4.00%	3.95%	3.84%	**4.04%**
Consol. Edison	High	$58.27	$58.80	$58.85	$60.36	$63.48	$64.94	
	Low	$57.07	$56.55	$56.56	$58.54	$60.29	$62.09	
	(High+Low)/2	$57.67	$57.68	$57.71	$59.45	$61.89	$63.52	**$59.65**
	Annual Dividend	$2.4000	$2.4050	$2.4050	$2.4050	$2.4100	$2.4100	
	Dividend Yield (Low)	4.12%	4.09%	4.09%	3.98%	3.80%	3.71%	**3.96%**
	Dividend Yield (High)	4.21%	4.25%	4.25%	4.11%	4.00%	3.88%	**4.12%**
	Dividend Yield (Average)	4.16%	4.17%	4.17%	4.05%	3.89%	3.79%	**4.04%**
Dominion Resources	High	$50.37	$50.84	$51.67	$52.06	$54.38	$54.97	
	Low	$48.85	$49.75	$49.67	$51.15	$51.47	$53.01	
	(High+Low)/2	$49.61	$50.30	$50.67	$51.61	$52.93	$53.99	**$51.52**
	Annual Dividend	$1.9700	$2.0050	$2.0050	$2.0050	$2.0300	$2.0300	
	Dividend Yield (Low)	3.91%	3.94%	3.88%	3.85%	3.73%	3.69%	**3.84%**
	Dividend Yield (High)	4.03%	4.03%	4.04%	3.92%	3.94%	3.83%	**3.97%**
	Dividend Yield (Average)	3.97%	3.99%	3.96%	3.89%	3.84%	3.76%	**3.90%**

Average Monthly Closing Stock Prices and Dividend Yields: Proxy Companies

FERC Monthly Average Stock Prices, Low, High Dividend Yields

Company	Stock Price	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Avg.
DTE Energy	High	$53.74	$55.31	$55.98	$56.28	$59.94	$61.66	
	Low	$52.09	$52.78	$53.30	$54.52	$55.81	$58.97	
	(High+Low)/2	$52.92	$54.05	$54.64	$55.40	$57.88	$60.32	**$55.87**
	Annual Dividend	$2.3000	$2.3275	$2.3275	$2.3275	$2.3550	$2.3550	
	Dividend Yield (Low)	4.28%	4.21%	4.16%	4.14%	3.93%	3.82%	**4.09%**
	Dividend Yield (High)	4.42%	4.41%	4.37%	4.27%	4.22%	3.99%	**4.28%**
	Dividend Yield (Average)	4.35%	4.31%	4.26%	4.20%	4.07%	3.90%	**4.18%**
Integrys Energy	High	$53.23	$53.46	$53.96	$54.27	$57.31	$61.11	
	Low	$51.16	$51.42	$50.58	$52.55	$53.65	$57.23	
	(High+Low)/2	$52.20	$52.44	$52.27	$53.41	$55.48	$59.17	**$54.16**
	Annual Dividend	$2.7200	$2.7200	$2.7200	$2.7200	$2.7200	$2.7200	
	Dividend Yield (Low)	5.11%	5.09%	5.04%	5.01%	4.75%	4.45%	**4.91%**
	Dividend Yield (High)	5.32%	5.29%	5.38%	5.18%	5.07%	4.75%	**5.16%**
	Dividend Yield (Average)	5.21%	5.19%	5.20%	5.09%	4.90%	4.60%	**5.03%**
NextEra	High	$59.66	$60.52	$63.95	$65.34	$68.81	$71.42	
	Low	$58.81	$58.98	$61.26	$62.98	$64.59	$67.86	
	(High+Low)/2	$59.24	$59.75	$62.61	$64.16	$66.70	$69.64	**$63.68**
	Annual Dividend	$2.2000	$2.2500	$2.2500	$2.2500	$2.3000	$2.3000	
	Dividend Yield (Low)	3.69%	3.72%	3.52%	3.44%	3.34%	3.22%	**3.49%**
	Dividend Yield (High)	3.74%	3.81%	3.67%	3.57%	3.56%	3.39%	**3.63%**
	Dividend Yield (Average)	3.71%	3.77%	3.59%	3.51%	3.45%	3.30%	**3.56%**

Average Monthly Closing Stock Prices and Dividend Yields: Proxy Companies

FERC Monthly Average Stock Prices, Low, High Dividend Yields

Company	Stock Price	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Avg.
OGE Energy	High	$52.95	$52.70	$53.55	$54.51	$53.90	$53.98	
	Low	$51.27	$50.89	$50.54	$52.33	$50.02	$50.88	
	(High+Low)/2	$52.11	$51.80	$52.05	$53.42	$51.96	$52.43	**$52.29**
	Annual Dividend	$1.5000	$1.5175	$1.5175	$1.5175	$1.5350	$1.5350	
	Dividend Yield (Low)	2.83%	2.88%	2.83%	2.78%	2.85%	2.84%	**2.84%**
	Dividend Yield (High)	2.93%	2.98%	3.00%	2.90%	3.07%	3.02%	**2.98%**
	Dividend Yield (Average)	2.88%	2.93%	2.92%	2.84%	2.95%	2.93%	**2.91%**
Pepco Holdings	High	$19.59	$19.39	$18.66	$18.82	$19.57	$20.16	
	Low	$18.91	$18.59	$18.06	$18.29	$18.96	$19.29	
	(High+Low)/2	$19.25	$18.99	$18.36	$18.56	$19.27	$19.73	**$19.02**
	Annual Dividend	$1.0800	$1.0800	$1.0800	$1.0800	$1.0800	$1.0800	
	Dividend Yield (Low)	5.51%	5.57%	5.79%	5.74%	5.52%	5.36%	**5.58%**
	Dividend Yield (High)	5.71%	5.81%	5.98%	5.90%	5.70%	5.60%	**5.78%**
	Dividend Yield (Average)	5.61%	5.69%	5.88%	5.82%	5.61%	5.48%	**5.68%**
SCANA Corp	High	$44.75	$45.17	$45.64	$46.46	$48.04	$49.65	
	Low	$43.65	$43.63	$43.54	$45.11	$46.21	$47.73	
	(High+Low)/2	$44.20	$44.40	$44.59	$45.79	$47.13	$48.69	**$45.80**
	Annual Dividend	$1.9300	$1.9400	$1.9400	$1.9400	$1.9500	$1.9500	
	Dividend Yield (Low)	4.31%	4.29%	4.25%	4.18%	4.06%	3.93%	**4.17%**
	Dividend Yield (High)	4.42%	4.45%	4.46%	4.30%	4.22%	4.09%	**4.32%**
	Dividend Yield (Average)	4.37%	4.37%	4.35%	4.24%	4.14%	4.00%	**4.24%**

Average Monthly Closing Stock Prices and Dividend Yields: Proxy Companies

FERC Monthly Average Stock Prices, Low, High Dividend Yields

Company	Stock Price	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Avg.
Sempra Energy	High	$58.11	$59.42	$64.22	$64.48	$68.88	$70.86	
	Low	$56.36	$57.08	$60.59	$62.85	$63.50	$68.07	
	(High+Low)/2	$57.24	$58.25	$62.41	$63.67	$66.19	$69.47	**$62.87**
	Annual Dividend	$1.8300	$1.9100	$1.9100	$1.9100	$2.0400	$2.0400	
	Dividend Yield (Low)	3.15%	3.21%	2.97%	2.96%	2.96%	2.88%	**3.02%**
	Dividend Yield (High)	3.25%	3.35%	3.15%	3.04%	3.21%	3.00%	**3.17%**
	Dividend Yield (Average)	3.20%	3.28%	3.06%	3.00%	3.08%	2.94%	**3.09%**
Southern Co.	High	$43.97	$44.47	$45.03	$45.44	$47.80	$47.92	
	Low	$43.14	$43.05	$43.44	$44.73	$45.48	$45.97	
	(High+Low)/2	$43.56	$43.76	$44.24	$45.09	$46.64	$46.95	**$45.04**
	Annual Dividend	$1.8700	$1.8875	$1.8875	$1.8875	$1.9050	$1.9050	
	Dividend Yield (Low)	4.25%	4.24%	4.19%	4.15%	3.99%	3.98%	**4.13%**
	Dividend Yield (High)	4.33%	4.38%	4.35%	4.22%	4.19%	4.14%	**4.27%**
	Dividend Yield (Average)	4.29%	4.31%	4.27%	4.19%	4.08%	4.06%	**4.20%**
TECO Energy	High	$17.67	$17.56	$17.58	$17.59	$18.07	$18.23	
	Low	$17.20	$17.06	$16.52	$17.02	$16.99	$17.45	
	(High+Low)/2	$17.44	$17.31	$17.05	$17.31	$17.53	$17.84	**$17.41**
	Annual Dividend	$0.8500	$0.8650	$0.8650	$0.8650	$0.8700	$0.8700	
	Dividend Yield (Low)	4.81%	4.93%	4.92%	4.92%	4.81%	4.77%	**4.86%**
	Dividend Yield (High)	4.94%	5.07%	5.24%	5.08%	5.12%	4.99%	**5.07%**
	Dividend Yield (Average)	4.88%	5.00%	5.07%	5.00%	4.96%	4.88%	**4.96%**

Average Monthly Closing Stock Prices and Dividend Yields: Proxy Companies

FERC Monthly Average Stock Prices, Low, High Dividend Yields

Company	Stock Price	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Avg.
Vectren Corp.	High	$29.36	$29.36	$29.10	$29.32	$29.93	$30.27	
	Low	$28.12	$28.38	$27.72	$28.61	$29.06	$29.41	
	(High+Low)/2	$28.74	$28.87	$28.41	$28.97	$29.50	$29.84	**$29.05**
	Annual Dividend	$1.3900	$1.3950	$1.3950	$1.3950	$1.4000	$1.4000	
	Dividend Yield (Low)	4.73%	4.75%	4.79%	4.76%	4.68%	4.63%	**4.72%**
	Dividend Yield (High)	4.94%	4.92%	5.03%	4.88%	4.82%	4.76%	**4.89%**
	Dividend Yield (Average)	4.84%	4.83%	4.91%	4.82%	4.75%	4.69%	**4.81%**
Wisconsin Energy	High	$34.08	$34.72	$36.26	$37.55	$39.28	$40.97	
	Low	$33.37	$33.56	$34.05	$35.68	$37.50	$39.58	
	(High+Low)/2	$33.73	$34.14	$35.16	$36.62	$38.39	$40.28	**$36.38**
	Annual Dividend	$1.0400	$1.0800	$1.0800	$1.0800	$1.1200	$1.1200	
	Dividend Yield (Low)	3.05%	3.11%	2.98%	2.88%	2.85%	2.73%	**2.93%**
	Dividend Yield (High)	3.12%	3.22%	3.17%	3.03%	2.99%	2.83%	**3.06%**
	Dividend Yield (Average)	3.08%	3.16%	3.07%	2.95%	2.92%	2.78%	**2.99%**
Xcel Energy	High	$26.09	$26.61	$26.82	$27.76	$28.75	$29.58	
	Low	$25.72	$25.73	$25.76	$26.66	$27.70	$28.59	
	(High+Low)/2	$25.91	$26.17	$26.29	$27.21	$28.23	$29.09	**$27.15**
	Annual Dividend	$1.0250	$1.0325	$1.0325	$1.0325	$1.0400	$1.0400	
	Dividend Yield (Low)	3.93%	3.88%	3.85%	3.72%	3.62%	3.52%	**3.75%**
	Dividend Yield (High)	3.99%	4.01%	4.01%	3.87%	3.75%	3.64%	**3.88%**
	Dividend Yield (Average)	3.96%	3.95%	3.93%	3.79%	3.68%	3.58%	**3.81%**

PRINCIPLES OF UTILITY CORPORATE FINANCE

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Are any Investments Truly Risk-free?

In setting regulated rates of return for utilities, some regulators will rely on models that estimate risk premiums above the return on so-called "risk-free" assets like U.S. Treasury Bills or Bonds, using models such as the Capital Asset Pricing Model, which we introduce in the next chapter. But are there any assets that really are risk-free?

In one sense, of course there are. If you buy a 20-year U.S. Treasury Bond and hold it until its maturity date, you are guaranteed to receive the face value of the bond, unless the U.S. Government disappears during the interim. In this sense U.S. Treasury Bonds are safe because they have no *default risk.* Similarly, you can buy a 3-month U.S. Treasury Bill and avoid any default risk. Or you can deposit money in your bank account and, assuming your deposit is fully insured, such as the U.S. Federal Deposit Insurance Corporation (FDIC) insures all deposits less than $250,000, then your money will also be completely safe.

But *safe* is not the same as *risk-free.* Both short-term and long-term assets, even if they are perfectly safe, can fluctuate in value. For example, if you purchase a 20-year Treasury Bond with a coupon rate of 5%, but then interest rates increase, the market value of that bond will decrease. This is called *price risk.* Similarly, if you buy a 3-month Treasury Bill with a coupon rate of 4%, the U.S. Federal Reserve could increase or decrease interest rates, which would cause the value of your T-bill to decrease or increase. Thus, even a completely safe asset can be risky.

Risk or Uncertainty

Most people use the terms "risk" and "uncertainty" interchangeably. Technically, however, they are not the same thing. *Risk* deals with known probabilities, such as flipping a fair coin. *Uncertainty* refers to events whose probabilities are not yet known. For a more detailed discussion, the classic reference is F. Knight, *Risk, Uncertainty, and Profit* (Boston: Houghton-Mifflin, 1933).

Does the distinction matter? In many financial applications, probably not. However, when we start addressing non-market issues, such as *regulatory uncertainty,* then the difference can be important. Specifically, when addressing capital budgeting issues, we will often need to address issues for which developing probabilities is difficult. For example, what is the probability that environmental regulators will introduce new pollution control regulations 10 years from now? Who knows? Not only is the nature of the regulation not even known, but attempting to estimate a probability based on (say) past events is dubious. That does not mean we cannot assign a probability, but in doing so we have to convert the uncertainty into a risk.

10.4 The Types of Risks Regulated Firms Face

Regulated firms face three types of risks: *business risk, financial risk,* and *regulatory risk.* Although all three are important, in this chapter and, indeed, for the remainder of the book, we will focus on measuring and addressing business and financial risk.

Financial Risk

A firm's financial risk stems from its financial structure. As we discussed in Chapter 3, the more a firm relies on debt financing, the greater its leverage, and the greater the risk it will not be able to service that debt. Greater leverage, therefore, increases the risks to equity investors, who have a lower claim on a firm's assets than do debtholders. As a result, equity investors require higher expected returns to compensate them for the additional financial risk they bear.

Similarly, equity investors themselves can face different levels of financial risk, depending on the nature of their investments. The investor that puts all of his money into a large corporation's stock faces a different level of financial risk than does an investor who puts all of his money in the penny stock of a start-up company. Moreover, while we often focus on the financial risk of a given stock or bond, for investors the key is the overall financial risk of the portfolio of assets they hold, as we discuss later in the chapter.

Business Risk

In Chapter 6, we introduced one measure of *business risk:* the standard deviation of a firm's net income relative to its average net income over a certain time period. That measure is appropriate because business risk is defined as the risk that a business will experience a period of poor earnings and, as a consequence, be unable to meet its financial obligations, such as the interest payments on its outstanding debt. A business that is at risk of not meeting its obligations on a going forward basis clearly imposes *financial risk* on its investors who, as a result of events affecting their investments in a firm, may not realize the return they had expected initially. Therein lies the difference between business and financial risk.

Regulated utilities face unique business risks for the simple reason that they are regulated. Firms that operate in competitive markets can respond to changing market conditions by adjusting their prices, shutting down factories, exiting an industry or entering a new one. But regulated utilities cannot do any of these without regulatory approval. As we discussed in Chapter 2, under cost of service regulation, a utility's anticipated cost to provide service is estimated. That estimate is based on a number of cost factors, such as labor costs, the cost for new capital investment, the cost of fuel, and so forth. The estimate is also based on forecast customer demand. With their estimates of costs and sales, regulators set rates and tariffs that, in theory, will exactly compensate the utility if those forecasts are accurate.

Of course such forecasts are never accurate, since forecasts can never capture every possible factor affecting costs and demand. Thus, if oil prices shoot up next year because OPEC decides to rein in output, a utility may find itself with higher costs and fewer purchases by its customers. As a result, the utility may not recover all of the costs to serve those customers and have no easy recourse, such as passing along higher prices, to recover those additional costs in a timely manner. Instead, the utility will have to file another rate case and hope to recover the additional costs in the future.

Similarly, for utilities that operate under incentive regulation, such as a price cap regime, the parameters may be set so that the utility cannot recover its costs. For example, regulators may require the utility to improve its productivity by several percent each year, even if the utility cannot achieve those improvements.

Regulatory Risk

Regulatory risk is another risk factor facing regulated firms that can increase both business and financial risk. Regulatory risk can encompass failing to adhere to *Good Regulatory Practice* that we defined in Chapter 2, for example by implementing *ex*-post changes in regulations. But it can also encompass *ex*-ante changes in how firms are regulated on a going-forward basis.[2] For regulated firms that must make significant capital investments in long-lived assets to meet their obligation to serve, frequent changes in how those firms are regulated leads to greater uncertainty and greater risk. Regulated firms rely on consistency from regulators and assurance that existing regulations will be applied in a fair and reasonable way. Regulatory risk occurs whenever changes in existing regulations or applications of those regulations are perceived by investors to be arbitrary and capricious and, as a consequence, viewed as jeopardizing the opportunity to earn risk-compensatory returns on their investments.[3]

10.5 Measuring Financial Risk

We previously defined financial risk as referring to a firm's capital structure, i.e., the relative amounts of the firm's outstanding debt and equity. That financial structure contributes to the variability associated with potential changes in the future value of the firm. The same holds true for a *portfolio* of financial instruments. As we will discuss later in the chapter, measuring portfolio risk depends on the financial risk of individual securities, as well as the ways the values of those securities may interact. However, rather than immediately leap into a discussion of portfolio risk, we begin by discussing how to measure the risk of individual assets.

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2 One might be tempted to argue that a firm's inability to meet the productivity factor improvement we discussed above is a form of regulatory risk. It is not, unless the regulator, having observed the firm meeting the productivity factor improvement, suddenly changes the required factor after-the-fact.

3 In the U.S., regulatory risk was first recognized as a distinct form of risk in a 1989 case before the U.S. Supreme Court: *Duquesne v. Barasch* 488 U.S. 299 (1989). The origin of the case dates to 1967, when Duquesne joined with other electric utilities in Pennsylvania in a plan to build seven nuclear generating plants. But in 1980, because of intervening events, including the first Arab oil embargo in 1973 and the 1977 accident at the Three Mile Island nuclear plant (located near Harrisburg, Pennsylvania), four of the plants were cancelled. Duquesne then applied to the Pennsylvania Public Utility Commission (PUC) for a rate increase and to amortize its expenditures on the canceled plants over 10 years. The PUC granted a rate increase that included an amount representing the first payment of the 10-year amortized recovery of Duquesne's costs in the aborted plants. But, shortly before the close of the rate proceeding, a new state law (Act 336) was enacted that forbid inclusion of CWIP (Construction Work in Progress) or AFUDC (Allowance for Funds Used During Construction) costs until the plant was actually generating electricity. Although the PUC still approved Duquesne's construction costs, the state's Consumer Advocate appealed the PUC decision. Ultimately, the Pennsylvania Supreme Court upheld the Consumer Advocate's appeal, holding that Act 336 prohibited recovery of the costs in question, whether as CWIP or AFUDC. The case was appealed to the U.S. Supreme Court, which affirmed the Pennsylvania Supreme Court's ruling.

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Cost of Capital Rate

Shading denotes an input | **2011**

Line No

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**
2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC's actual capital structure and will equal the sum of (i), (ii), and (iii) below:
3
4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-en
5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year end exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end
6 of the year balances of the following: long term debt less the unamortized Discounts on Long-Term Debt less the unamortized
7 Loss on Reacquired Debt plus Unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and any loss or gain on reacquired debt.
8
9 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;
10
11 (iii) the return on equity component shall be the product of the allowed return on equity o f 11.5% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratio
12 shall not exceed fifty percent (50%).

Line			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL		WEIGHTED COST OF CAPITAL	EQUITY PORTION
13–16									
17	(i)	LONG-TERM DEBT	$2,375,583,081	Workpaper 6, Line 16b	49.53%	3.96%	Workpaper 6, Line 17c	1.96%	
18	(ii)	PREFERRED STOCK	$28,984,701	FF1 112.3c	0.47%	3.66%	Workpaper 6, Line 24d	0.02%	0.02%
19	(iii)	COMMON EQUITY	$3,813,721,822	112.16c - FF1 112.3,12,15c	50.00%	11.50%	Per Tariff	5.75%	5.75%
20									
21		TOTAL INVESTMENT RETURN	$6,218,289,604		100.00%			7.73%	5.77%

22
23
24
25
26 9.2.2.(b) Federal Income Tax shall e = (A. + [B / C] X Federal Income Tax Rate)
27 (1 - Federal Income Tax Rate)
28
29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for
30 Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
31
32 = (0.0577 +($6,061,115) / $1,152,171,571 X 35%)
33 (1 - 0.35)
34
35 = 0.0339019
36
37
38 9.2.2.(c) State Income Tax shall equ = (A. + [B / C] + Federal Income Tax) X State Income Tax Rate
39 (1 - State Income Tax Rate)
40
41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in
42 Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
43
44
45
46 = (0.0577 +($6,061,115) / $1,152,171,571 + 0.0339019) X 7.10%
47 (1 - 7.10%)
48
49 = 0.0074028
50
51
52
53 (a)+(b)+(c) Cost of Capital Rate = 11.86%
54
55
56 **9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate**
57
58
59
60 Transmission Investment Base $1,152,171,571 Schedule 6, page 1 of 2, Line 28
61
62 Cost of Capital Rate 0.1186047 Line 53
63
64 = Investment Return and Income Taxes $136,652,963 Line 60 * Line 62

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Cost of Capital Rate

Shading denotes an input | **2011**

Line No

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**
2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC's actual capital structure and will equal the sum of (i), (ii), and (iii) below:
3
4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; anc
5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year end exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end
6 of the year balances of the following: long term debt less the unamortized Discounts on Long-Term Debt less the unamortized
7 Loss on Reacquired Debt plus Unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and any loss or gain on reacquired debt.
8
9 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;
10
11 (iii) the return on equity component shall be the product of the allowed return on equity o f 11.5% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratio
12 shall not exceed fifty percent (50%).

Line No			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL		WEIGHTED COST OF CAPITAL	EQUITY PORTION
13									
14									
15									
16									
17	(i)	LONG-TERM DEBT	$2,375,583,081	Workpaper 6, Line 16b	49.53%	3.96%	Workpaper 6, Line 17c	1.96%	
18	(ii)	PREFERRED STOCK	$28,984,701	FF1 112.3c	0.47%	3.66%	Workpaper 6, Line 24d	0.02%	0.02%
19	(iii)	COMMON EQUITY	$3,813,721,822	112.16c - FF1 112.3,12,15c	50.00%	**9.49%**	Per Tariff	4.75%	4.75%
20									
21		TOTAL INVESTMENT RETURN	$6,218,289,604		100.00%			**6.730%**	4.77%

22
23
24
25
26 9.2.2.(b) Federal Income Tax shall e = (A. + [B / C] X Federal Income Tax Rate)
27 (1 - Federal Income Tax Rate)
28
29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for
30 Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
31
32 = (0.0477 +($6,061,115) / $1,152,171,571 X 35%)
33 (1 - 0.35)
34
35 = 0.0285172
36
37
38 9.2.2.(c) State Income Tax shall equ = (A. + [B / C] + Federal Income Tax) X State Income Tax Rate
39 (1 - State Income Tax Rate)
40
41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in
42 Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
43
44
45
46 = (0.0477 +($6,061,115) / $1,152,171,571 + 0.0285172) X 7.10%
47 (1 - 7.10%)
48
49 = 0.0062270
50
51
52
53 (a)+(b)+(c) Cost of Capital Rate = 10.20%
54
55
56 **9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate**
57
58
59
60 Transmission Investment Base $1,152,171,571 Schedule 6, page 1 of 2, Line 28
61
62 Cost of Capital Rate 0.1020442 Line 53
63
64 = Investment Return and Income Taxes **$117,572,426** Line 60 * Line 62

Service List For NYAPP Complaint

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Exhibit No. NYP-10

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New York Association of Public Power Complainant, v. Niagara Mohawk Power Corporation d/b/a National Grid, Respondent.	)))))))))	Docket No. EL12-___-000

NOTICE OF COMPLAINT

(March 6, 2009)

Take notice that on September 11, 2012, the New York Association of Public Power (Complainant) filed a complaint against Niagara Mohawk Power Corporation d/b/a National Grid (Respondent) pursuant to Section 206 of the Federal Power Act, seeking an order to reduce the 11.5 percent return on equity ("ROE") used in calculating rates for transmission service under the New York Independent System Operator, Inc.'s ("NYISO") Open Access Transmission Tariff ("OATT") to a just and reasonable level at 9.49 percent, inclusive of a 50 basis point adder for participation in the NYISO, with a corresponding overall weighted cost of capital of 6.73 percent.

Complainants certify that copies of the complaint were served on the contacts for Niagara Mohawk Power Corporation as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose,
Secretary

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