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October 28, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CENTERPOINT INDIANA SOUTH") FOR AN ORDER: (1) AUTHORIZING CENTERPOINT INDIANA SOUTH TO ENTER INTO A POWER PURCHASE AGREEMENT ("PPA") TO PURCHASE ENERGY AND CAPACITY FROM A 185 MW SOLAR PROJECT IN VERMILLION COUNTY, INDIANA (THE "VERMILLION COUNTY SOLAR PROJECT"), AND FINDING THE TERMS OF THE PPA REASONABLE AND NECESSARY; (2) AUTHORIZING CENTERPOINT INDIANA SOUTH TO ENTER INTO A PPA TO PURCHASE ENERGY AND CAPACITY FROM A 150 MW SOLAR PROJECT IN KNOX COUNTY, INDIANA (THE "KNOX COUNTY SOLAR PROJECT"), AND FINDING THE TERMS OF THE PPA REASONABLE AND NECESSARY; (3) DETERMINING THE VERMILLION COUNTY SOLAR PROJECT AND KNOX COUNTY SOLAR PROJECT TO BE ELIGIBLE CLEAN ENERGY PROJECTS FOR PURPOSES OF IND. CODE CH. 8-1-8.8; (4) AUTHORIZING THE FULL RECOVERY OF THE POWER PURCHASE COSTS UNDER THE PPAS FROM CUSTOMERS THROUGH FUEL ADJUSTMENT CLAUSE ("FAC") PROCEEDINGS OVER THE ENTIRE TERM OF THE PPAS; (5) APPROVING RATEMAKING TREATMENT TO ACCOUNT FOR INCREASED COST OF DEBT ASSOCIATED WITH THE PPAS AND AUTHORIZING EXPENSES ASSOCIATED WITH ENTERING INTO THE PPAS BE DEFERRED AS REGULATORY ASSETS FOR RECOVERY THROUGH THE FAC; (6) APPROVING CONFIDENTIAL TREATMENT OF THE PPA PRICING AND OTHER NEGOTIATED COMMERCIAL TERMS AND RELATED CONFIDENTIAL INFORMATION.	**)**	**CAUSE NO. 45600**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 1

TESTIMONY OF OUCC WITNESS CALEB R. LOVEMAN

OCTOBER 28, 2021

Respectfully submitted,

T. Jason Haas
Attorney No. 34983-29
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS CALEB R. LOVEMAN
CAUSE NO. 45600
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A CENTERPOINT ENERGY INDIANA SOUTH

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Caleb R. Loveman, and my business address is 115 W. Washington St., Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed as a Utility Analyst in the Indiana Office of Utility Consumer Counselor's ("OUCC") Electric Division. A summary of my educational background and experience is included in Appendix A attached to my testimony.

Q: What is the purpose of your testimony?

A: I provide my analysis and make recommendations on Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South's ("CenterPoint" or "Petitioner") request to enter into a Power Purchase Agreement ("PPA") with Oriden LLC's affiliate, Vermillion Rise Solar LLC, ("Oriden") to purchase energy, capacity, and Renewable Energy Credits ("REC") from a 185 megawatt alternating current ("MWac") solar project in Vermillion County, Indiana ("Vermillion County Solar Project") over a 15-year term, and to enter into a PPA with Origis Energy's affiliate, IN Solar 1 LLC, ("Origis") to purchase energy, capacity, and RECs from a 150 MWac solar project in Knox County, Indiana ("Knox County Solar Project") over a 20-year term. Specifically, I address CenterPoint's proposed: (1) adders to its Vermillion and Knox County Solar Project PPAs and (2) request to create regulatory assets to recover the costs incurred in negotiating the PPAs. I recommend the Indiana Utility Regulatory Commission ("Commission"):

1) Deny Petitioner's request for an adder to its Vermillion and Knox County Solar Project PPAs, as the Commission did in Cause No. 45501;
2) Deny Petitioner's request to create regulatory assets to recover the costs incurred in negotiating the PPAs;
3) Accept Petitioner's proposed Vermillion and Knox County Solar Project PPAs, excluding the requested debt adder and incremental costs I recommend the Commission deny; and
4) Accept Petitioner's request to recover direct costs associated with the Vermillion and Knox County Solar Projects through its Fuel Adjustment Clause ("FAC") tracker, excluding the requested debt adder and incremental costs I recommend the Commission deny.

Q: Please describe the review and analysis you conducted in order to prepare your testimony.

A: I reviewed CenterPoint's petition, testimonies, exhibits, and workpapers. I issued formal data requests ("DR") and reviewed Petitioner's responses. Additionally, I reviewed Cause Nos. 45086, 44909, 43839, and 45501, and their respective Final Orders. Cause No. 45501 included, in part, a similar request to this proceeding by CenterPoint for recovery related to a PPA for the Warrick County Solar Project. I also reviewed relevant portions of the Indiana Code ("Ind. Code").

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with Petitioner's proposal?

A: No. Excluding any specific adjustments, amounts, or requests CenterPoint proposes does not indicate my approval of those adjustments, amounts, or requests. Rather, the scope of my testimony is limited to the specific items addressed herein.

II. VERMILLION AND KNOX COUNTY SOLAR PROJECTS

Q: What relief is Petitioner requesting as it relates to the Vermillion County Solar Project?

A: CenterPoint requests authorization to enter into a 15-year PPA with Oriden to purchase power from the Vermillion County Solar Project and to find the PPA terms reasonable. Additionally, CenterPoint requests full recovery of power purchase costs under the PPA from customers through the FAC tracker over the entire term of the PPA. CenterPoint also requests its proposed ratemaking treatment accounting for increased cost of debt related to the Vermillion County Solar Project PPA be approved, allowing CenterPoint to earn a return on the PPAs. Finally, CenterPoint requests to create a regulatory asset and recover direct incremental costs associated with negotiating the Vermillion County Solar Project PPA via amortizing the costs over the life of the Vermillion County Solar Project PPA and recovery through CenterPoint's FAC tracker. All recovery is done pursuant to Ind. Code §§ 8-1-2-42(a) and 8-1-8.8-11.[1]

Q: What relief is Petitioner requesting as it relates to the Knox County Solar Project?

A: CenterPoint requests authorization to enter into a 20-year PPA with Origis to purchase power from the Knox County Solar Project and to find the PPA terms reasonable. Additionally, CenterPoint requests full recovery of power purchase costs under the

[1] Petition, paragraph 9.

PPA from customers through the FAC tracker over the entire term of the PPA. CenterPoint also requests its proposed ratemaking treatment accounting for increased cost of debt related to the Knox County Solar Project PPA be approved, allowing CenterPoint to earn a return on PPAs. Finally, CenterPoint requests to create a regulatory asset and recover direct incremental costs associated with the Knox County Solar Project PPA via amortizing the costs over the life of the Knox County Solar Project PPA and recover through CenterPoint's FAC tracker. All recovery pursuant to Ind. Code §§ 8-1-2-42(a) and 8-1-8.8-11.[2]

III. VERMILLION AND KNOX COUNTY SOLAR PROJECTS PPA ADDERS

Q: Please describe CenterPoint's requested adder to its Vermillion and Knox County Solar Project PPAs.

A: Pursuant to Ind. Code § 8-1-8.8-11, CenterPoint requests an adder to its Vermillion and Knox County Solar Project PPAs as a solution to potential various credit rating agencies assessing an imputed debt to CenterPoint as a result of its PPA obligation.[3] CenterPoint witness Brett A. Jerasa explains CenterPoint's proposal includes a PPA adjustment and uses the ratio restoration method to restore its credit metrics and provides an explanation regarding how this is calculated. He states, "an alternative would be to assign a fixed rate of $6.10 for the Vermillion County Solar Project and a fixed rate of $8.19 for the Knox County Solar Project based on the total PPA adjustments and a weighted average cost of capital ("WACC") of 7.17%."[4]

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[2] Petition, paragraph 9.
[3] Direct Testimony of Brett A. Jerasa, p.11, lines 8-20; and p. 13, line 14 to p. 14, line 2.
[4] *Id.*, p. 11, line 8 to p. 12, line 20.

Q: What is your understanding of the debt equivalence concern Mr. Jerasa raises?

A: Credit rating agencies, such as Standard's and Poor's ("S&P") and Moody's, may view long-term PPAs as a fixed-debt-like financial obligation.[5]

Q: Please describe the potential ratepayer impacts resulting from credit rating agencies assessing an imputed PPA debt described by CenterPoint.

A: By entering into long-term contracts with a third party for a fixed amount of generation, the utility effectively creates a long-term liability for future payments.[6] These fixed payment obligations can potentially reduce financial flexibility and could lead to an increase in the utility's financial risk profile.[7] This increased financial risk profile potentially weakens a utility's credit metrics and credit profile.[8] This can lead to a credit downgrade if a utility is near its downgrade threshold.[9] Weaker credit ratings could ultimately increase borrowing costs and negatively impact a utility's cost of capital.[10] Mr. Jerasa states deteriorated credit quality results in increased cost of debt, which ultimately is paid for by our customers through higher bills.[11] This would happen only if a credit rating agency assesses an imputed debt on a utility that leads to a credit downgrade.

Q: What methods are you aware of to combat the potential for credit rating agencies assessing debt equivalence?

A: I am aware of three different methods. The California Public Utilities Commission Policy & Planning Division released a document titled, "An Introduction to Debt Equivalency" ("CPUC Debt Equivalency Document"). This document is attached as

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[5] *Id.*, p. 5, line 23 to p. 6, line 2, and p. 6, lines 10-30.
[6] *Id.*, p. 7, lines 8-9.
[7] *Id.*, p. 7, lines 10-11.
[8] *Id.*, p. 7, lines 15-16.
[9] *Id.*, p. 9, lines 22-23.
[10] *Id.*, p. 7 lines 16-17.
[11] Id., p. 10, lines 9-10.

OUCC Attachment CRL-1. The document provides a detailed introduction and explanation to debt equivalency associated with PPAs and provides an explanation of S&P's three different methods to combat debt equivalency.

Method One: Adjust the utility's capital structure (equity ratio) to mitigate PPA impacts. This is completed by issuing more equity to increase the amount of equity in rate base. Issuing equity can be expensive and this cost would be passed on to ratepayers.

Method Two: Increase the utility's return on equity ("ROE") to mitigate the impact of PPAs. Essentially, a utility would need to increase its ROE until the pre-PPA WACC is equal to the post-PPA WACC. This would be accomplished through a general rate case. This method does not fully restore any credit ratios; however, it does compensate shareholders for the increased risk of debt equivalency.

Method Three: Offset the negative effects of imputed debt by collecting a return on the amount of imputed equity as an adder to the PPA bids. Essentially, the utility imputes new equity to offset imputed debt. This is the costliest method of the three.

Q: Which method does Petitioner propose?

A: CenterPoint proposes method three – an adder to the Vermillion and Knox County Solar Project PPAs in the form of imputed equity to offset any potential for imputed debt. According to the CPUC Debt Equivalency Document, the method CenterPoint chose is the most expensive of the three methods, and this method is more appropriate for a utility with a low credit rating. Additionally, Mr. Jerasa's Attachment BAJ-9 reads as follows:

> The second broad approach focuses on (partially) restoring some of the financial ratios to their pre-contract values. Because this approach is, in general, more expensive for rate payers than the first approach, it is only appropriate for a utility that does not have an investment grade credit rating or which is in danger of a downgrade to a non-investment grade rating if the negative effects of signing long-term PPAs are not addressed.[12]

Q: Does Petitioner anticipate these PPAs will cause a credit downgrade through an assessed debt equivalence?

A: CenterPoint does not indicate the Vermillion and Knox County Solar PPAs will cause a credit rating downgrade. Mr. Jerasa's only states "it is possible."[13]

Q: What are Petitioner's current credit ratings and does S&P or Moody's assess a PPA debt equivalence to CenterPoint?

A: S&P assigned CenterPoint an issuer credit rating, currently BBB+ with a stable outlook, and S&P rated CenterPoint's outstanding senior secured first mortgage bonds as A.[14] Moody's assigned CenterPoint a long-term issuer rating of A3 with a stable outlook, and Moody's rated CenterPoint's outstanding senior secured first mortgage bonds as A1.[15] To date, neither S&P nor Moody's included a PPA debt equivalence in their CenterPoint ratings.[16]

Q: What key credit risks and credit strengths does S&P highlight for CenterPoint?

A: As of April 29, 2021, S&P's most recent credit update, it highlighted the following credit risks:

- Environmental, Social, and Governance considerations are material because more than 90% of its generation supply is from coal.
- Negative discretionary cash flow after capital spending.

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[12] *Id.* Attachment BAJ-9, pp. 31-32.
[13] *Id.*, p. 10, lines 12-22.
[14] *Id.*, p. 4, lines 11-13.
[15] *Id.*, lines 30-32.
[16] *Id.*, p. 7, line 29 to p. 8, line 1.

- Relatively smaller customer base heightens business risk.

In this same report, S&P highlighted the following credit strengths:

- Utility operations benefit from generally constructive regulatory framework.
- Strong financial measures provide cushion against unexpected cash outflows.
- Base of mostly residential retail customers provides greater cash flow stability.[17]

Additionally, S&P states the following:

> ***We view Southern Indiana Gas & Electric Co.'s (SIGECO) revised integrated resource plan (IRP) as potentially supportive of its credit quality.*** In the company's revised IRP, it proposes replacing 730 megawatts (MW) of its existing coal-fired generation with significant renewable capacity and dispatchable natural gas combustion turbines. If adopted, these new generation assets could lower SIGECO's exposure to environmental risk factors, including the ongoing cost of operating older coal-fired units and the potential for increasing environmental regulations requiring significant capital investments.
>
> ***SIGECO's regulatory and legislative environment also support its credit quality.*** The company's regulators have authorized various mechanisms for utilities to recover their costs outside a base rate case, including Senate Bill 560, which targets the recovery of costs related to electric and natural gas system reliability and costs to expand natural gas services to rural areas. SIGECO also benefits from fuel cost recovery mechanisms, decoupling and lost margin recovery, all supporting EBITDA growth and providing steady operating cash flow.[18]

Q: Has S&P updated CenterPoint's outlook since CenterPoint filed testimony in Cause No. 45501?

A: Yes. In Cause No. 45501, Mr. Jerasa's provided CenterPoint's S&P Global Ratings Report, dated April 9, 2020, indicating a negative outlook for CenterPoint.[19] In the

[17] *Id.*, Attachment BAJ-1, p. 2.
[18] *Id.*
[19] Cause No. 45501, Direct Testimony of Brett A. Jerasa, Attachment BAJ-1, p. 4.

current Cause, Mr. Jerasa provides S&P Global's most recent report, dated April 29, 2021, indicating a stable outlook for CenterPoint.[20]

Q: Based on your review of Mr. Jerasa's testimony and attachments, do you support CenterPoint's requested adder?

A: No. CenterPoint has not demonstrated it, nor its customers, will be monetarily harmed via a debt equivalency if assessed by a credit rating agency for the Vermillion and Knox County Solar Project PPAs. CenterPoint has not sufficiently demonstrated S&P or Moody's will assess a debt equivalency for CenterPoint's PPAs. As CenterPoint proposes, and the OUCC does not object to, the Vermillion and Knox County Solar Project PPAs' costs will be recovered through its FAC tracker. As a result, CenterPoint will achieve full PPA cost recovery. Additionally, the method CenterPoint requests is not appropriate for CenterPoint's current position, as CenterPoint has investment grade credit ratings from both S&P and Moody's. Mr. Jerasa's concern about a potential credit downgrade is completely speculative at this point in time.

Q: If S&P assessed a debt equivalency for the Vermillion and Knox County Solar Project PPAs, as described by Mr. Jerasa, will CenterPoint's Funds from Operations ("FFO") to debt be below S&P's expected FFO to debt range for CenterPoint?

A: No. According to Mr. Jerasa, S&P expects CenterPoint's FFO to debt to be in the 19-21% range, and a metric materially below that expectation may contribute to a downgrade.[21] Mr. Jerasa's Table 1 shows the cumulative impact on CenterPoint's FFO to debt for the Vermillion and Knox County Solar Project PPAs, and the Warrick County Solar Project PPA from Cause No. 45501. If S&P assesses a debt equivalence at the risk factor stated by Mr. Jerasa to the two PPAs in this proceeding and the PPA

[20] Jerasa Direct, Attachment BAJ-1, p. 3.
[21] *Id.*, p. 9, lines 25-27.

from Cause No. 45501, the cumulative impact on CenterPoint's Pro-Forma FFO to debt would be -1.84%, 21.5% to 19.7%, as calculated by Mr. Jerasa. Even if S&P were to impute debt, the percentages Mr. Jerasa provided are still within the 19-21% expected range and would not put CenterPoint below S&P's expectation, "materially" or otherwise. CenterPoint would still be within the expected range.

Q: Are you aware of any Indiana utilities that have been assessed a debt equivalency by either S&P or Moody's?

A: No. I am only aware of S&P assessing a debt equivalency to American Electric Power Company, Indiana Michigan Power Company's Parent company. The S&P report is unclear regarding which PPAs were used to calculate this debt equivalency.[22]

Q: In his testimony, Mr. Jerasa indicated the OUCC did not object to the proposed methodology in Cause No. 45501, which is the same methodology proposed in the current Cause. How do you respond?

A: The OUCC did not directly address the specific methodology, as the OUCC objects to the entire idea of a debt adder for CenterPoint's proposed PPAs. It is irrelevant whether the OUCC objects to or does not object to CenterPoint's proposed methodology. The OUCC does not support the proposed idea of a debt adder for the "potential" of an imputed debt that has not been realized by CenterPoint or any other investor-owned utility in the state of Indiana. CenterPoint will achieve full recovery of the PPAs' costs via its FAC proceedings.

[22] *See* OUCC Attachment CRL-2, CenterPoint Response to OUCC DR 1.1, S&P AEP.

Q: Did the Commission address this issue in its Cause No. 45501 Order dated October 27, 2021?

A: Yes. In response to CenterPoint's request for a debt adder for the Warrick County Solar Project PPA, the Commission ordered the following:

> The Commission recognizes the potential risk that rating agencies may assess a debt equivalency on a utility that enters into a PPA; however, CenterPoint acknowledged the Warrick Project PPA will not lead to a downgrade of its credit ratings. Petitioner's Exh. 8 at p. 11; Petitioner's Exh. 8-R at p. 4. In addition, to date, S&P has not included a debt adjustment for CenterPoint's current PPAs. Based on this record, we agree with the OUCC that Petitioner has not proven the need for this adder in this proceeding or demonstrated this adder will be beneficial to its customers. We find it is not prudent to approve an adder when its necessity is in question and the benefits were not demonstrated. We are also reluctant to approve the proposed adder based on speculation upon the impact in the future to Petitioner's credit metrics. Accordingly, while the Commission is authorized and encouraged under Ind. Code § 8-1-8.8-11 to award financial incentives for clean energy projects, consistent with the foregoing, the Commission finds it is not appropriate to approve the proposed adder for debt equivalency at this time.[23]

Q: What does the OUCC recommend regarding CenterPoint's Vermillion and Knox County Solar Project adders?

A: The OUCC recommends the Commission makes the same decision in this proceeding that it made in Cause No. 45501 and deny CenterPoint's proposed debt equivalency adders. Although the OUCC recognizes the potential for a credit rating agency to assess a debt equivalency, the OUCC does not agree CenterPoint's Vermillion and Knox County Solar Project PPAs warrant any modification to the current PPA price to adjust for debt equivalency via a high cost to consumers through a debt adder. The addition of debt equivalency should not be done on an *ad hoc* basis for each project, as CenterPoint is proposing. CenterPoint has been unable to demonstrate benefits to its

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[23] *In re Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South.,* Cause No. 45501, Final Order (Ind. Util. Regul. Comm'n Oct. 27, 2021).

customers via its proposed debt adder at this time. Therefore, the OUCC recommends the Commission deny CenterPoint's request.

IV. INCREMENTAL SOLAR PROJECT PPA COSTS

Q: Please describe CenterPoint's incremental costs recovery request.

A: CenterPoint requests to defer, as a regulatory asset, incremental expenses associated with the Vermillion and Knox County Solar Project PPAs, such as legal, accounting/auditor fees, or other expenses related to the procurement, review, execution, or implementation of each Solar PPA, and recover such expenses through the FAC over the life of each solar project.[24]

Q: Did CenterPoint provide an estimate of the expected incremental costs?

A: Yes. CenterPoint estimates $270,532 in incremental costs. CenterPoint proposes to allocate half of this amount, $135,266, to each of the Vermillion and Knox County Solar Projects.[25] Therefore, CenterPoint proposes to amortize $135,266 over a 15-year life for the Vermillion County Solar Project and to amortize $135,266 over a 20-year life for the Knox County Solar Project.

Q: Did CenterPoint request recovery of similar costs for its Warrick County Solar Project PPA in Cause No. 45501?

A: No. These incremental costs were not requested for recovery nor discussed in Cause No. 45501. It is unclear why CenterPoint is requesting to recover these costs in this proceeding.

[24] Direct Testimony of Kara R. Gostenhofer, p. 9, lines 1-10.
[25] *Id.*, p. 9, line 24 to p. 10, line 5.

Q: Does the OUCC support CenterPoint's request for cost recovery of these incremental costs?

A: No. CenterPoint's request is contrary to traditional ratemaking. The purpose of base rates, as set in a rate case, are to recover costs such as these. When base rates are set in a rate case, it is a snapshot in time, and it is generally understood not all expenses shown in the test year will continue at the exact level as shown in the test year for each continuing year. It is also understood that a utility may incur expenses in the future that are not shown in the test year.

CenterPoint's request to recover these incremental costs is piecemeal ratemaking. The costs CenterPoint requests to recover are part of its normal business operations and should not be granted special ratemaking treatment. Although these amounts would result in a minor impact on a customer's bill, CenterPoint's request should be denied as it is against traditional ratemaking principles. The OUCC recommends the Commission deny CenterPoint's request to recover the expected incremental costs over the life of the Vermillion and Knox County Solar Project PPAs.

V. VERMILLION AND KNOX COUNTY SOLAR PROJECT PPAS

Q: What is the OUCC's position on the proposed Vermillion and Knox County Solar Project PPAs?

A: With the modifications identified above, the OUCC recommends the Commission approve CenterPoint's proposed Vermillion and Knox County Solar Project PPAs.

VI. VERMILLION AND KNOX COUNTY SOLAR PROJECTS COST RECOVERY

Q: How does Petitioner request recovering the Vermillion and Knox County Solar Project PPAs' costs?

A: Pursuant to Ind. Code §§ 8-1-2-42(a) and 8-1-8.8-11, CenterPoint requests full recovery of the costs associated with the PPAs from customers via a rate adjustment mechanism over the entire 15-year and 20-year PPA terms. For administrative efficiency, CenterPoint proposes having the cost recovery administered through the FAC tracker over the entire PPA term.[26]

Q: Do you have any concerns with Petitioner’s cost recovery request, other than CenterPoint’s proposed debt adders and recovery of direct incremental costs?

A: No. If the Commission approves the Vermillion and Knox County Solar Projects, I recommend approving CenterPoint’s proposal to recover costs associated with the PPAs, excluding certain costs I identify above and recommend denial of, through the FAC tracker. This treatment is consistent with the cost recovery approved in Cause Nos. 43259 and 43635 for purchases from the Benton County Wind Farm and Fowler Ridge II.[27]

VII. RECOMMENDATIONS

Q: What do you recommend?

A: Based on my analysis described above, I recommend the Commission:

1) Deny Petitioner’s request for a debt adder to its Vermillion and Knox County Solar Project PPAs;
2) Deny Petitioner’s request to create regulatory assets to recover the direct incremental costs associated with the PPAs;
3) Accept Petitioner’s proposed Vermillion and Knox County Solar Project PPAs, excluding costs identified above; and

[26] Petition paragraph 9.
[27] *In re Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.*, Cause No. 43259, Final Order (Ind. Util. Regul. Comm’n Dec. 05, 2007); and *In re Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.*, Cause No. 43635, Final Order (Ind. Util. Regul. Comm’n Jun. 17, 2009).

4) Accept Petitioner's request to recover costs associated with the Vermillion and Knox County Solar Projects, excluding costs identified above, through its FAC tracker.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A – Qualifications of Caleb R. Loveman

Q: Please describe your background and experience.

A: I graduated from Franklin University in 2015 with a Bachelor of Science in Accounting. From 2016 to 2019, I owned and operated an E-commerce business. During this time, I also worked as a Staff Accountant for Legacy Administration Services, LLC and as a Financial Analyst for Cummins, Inc. to gain additional accounting experience. I began my career with the OUCC in July 2019 as a Utility Analyst in the Electric Division. I review Indiana utilities' requests for regulatory relief filed with the Commission. I also prepare and present testimony based on my analyses and make recommendations to the Commission on behalf of Indiana utility consumers. I attended "The Basics" Practical Regulatory Training for the Electric Industry, sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") and the New Mexico State University Center for Public Utilities, in Albuquerque, New Mexico in 2019. I also attended the Indiana Energy Association ("IEA") 2019 Energy Conference and the Indiana Industrial Energy Consumers, Inc. ("INDIEC") 2019 Indiana Energy Conference. In 2020, I attended the Institute of Public Utilities Accounting and Ratemaking Course at Michigan State University and the INDIEC 2020 Indiana Energy Conference.

Q: Have you previously filed testimony in other Commission proceedings?

A: Yes.

An Introduction to Debt Equivalency

California Public Utilities Commission

Policy & Planning Division

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August 4, 2017

Contents

I. Introduction

With the growth of wholesale markets many utilities rely on long-term purchase power agreement (PPA) to meet the power supply needs of their customers. A PPA represents a long-term financial obligation. Under a long-term PPA the utility is obligated to make fixed payments for available capacity or take-or-pay energy payments over multiple years.

PPAs have both benefits and risks to the utility. Utilities have a choice of either signing PPAs or finance and build their own generation. By entering into a PPA the utility shifts construction and operating risks such as operating cost overruns, performance shortfalls, and technology obsolesce to the suppliers. Another benefit of PPA to the utility is that it allows diversity in procurement.

The principal risk borne by a utility that relies on PPAs is the recovery of financial obligations in rates. The utility that relies on a PPA will have a fixed payment obligation without an associated debt obligation reported on its balance sheet. The fixed payment obligation creates financial risk for purchasing utility. For example, the PPA payment obligation means less cash will be available to make payments to bondholders.

- ***This report explores the issue of Debt Equivalency by explaining why it is important and reviews options for addressing it.***

Under generally accepted accounting principles, utilities do not report PPA obligations in their balance sheets as debt, but credit-rating agencies treat the utility's commitments under PPAs as debt-like financial obligations. "Debt Equivalency" is a term used by credit analysts to describe the debt-like financial obligations resulting from signing long-term contracts. Credit-rating agencies incorporate Debt Equivalency in their credit analysis.

Utilities in California have raised the issue of Debt Equivalency in different proceedings. The Commission's long standing position is that the impact of Debt Equivalency on utilities' financial condition should be addressed in Cost of Capital proceedings. In addition in Long-term Procurement proceedings the Commission has been considering the Debt Equivalency impact of new long-term commitments in the contract selection and approval process in some cases.

The Commission has acknowledged that rating agencies impute debt from long-term PPAs and incorporate that in their credit analysis. But the Commission has not adopted a comprehensive policy on the cost recovery treatment of Debt Equivalency. In Cost of Capital proceedings the Commission has ruled that Debt Equivalency should be assessed on a case-by-case basis along with other financial, regulatory and operational risks in setting a balanced capital structure and fair return on equity (ROE).

The Commission has applied the strategy of setting a balanced capital structure and fair ROE on case-by-case basis differently over the years. In 2006 and 2008 Cost of capital decision (D.05-12-043 and D.12-12-034) the strategy resulted in increasing the ROE range by a Debt Equivalency premium to compensate utilities for the risk of PPAs. In addition the Commission approved an ROE toward the upper end of the parties' proposed ROE range.

In contrast in the 2013 Cost of capital decision, the approach resulted in choosing an authorized ROE at the top of the ROE range with no additional increases in the ROE range. The Commission did not grant a Debt Equivalency premium for test year 2013 even though in the 2013 Cost of Capital Decision, D. 12-12-034, the Commission acknowledged that there had been an increase in the number of procurement transactions the utilities were entering into.[1]

The Debt Equivalency premiums that the Commission granted for test year 2006 and 2008 can explain a large part of what has become known as California Premium. The major utilities in California have been earning a return on equity (ROE) higher than the national average. The Debt Equivalency premiums granted for test year 2006 and 2008 together covered a 7 year period from 2006 through 2012.

The remainder of this report is divided into seven parts. Section II discusses why Debt Equivalency is important. Section III discusses how Debt Equivalency is addressed by credit rating agencies. Section IV describes S&P methodology for incorporating Debt Equivalency into credit ratings analysis. Section V describes S&P methodology for mitigating the impact of Debt Equivalency. Section VI describes how the issue of Debt Equivalency has been addressed by the Commission. Finally section VII summarizes the findings.

II. Why is it important?

Debt equivalency is a term used by credit analysts to describe the financial risk inherent in the fixed financial obligation resulting from signing long-term contracts, such as PPA or operating leases. Although such contractual commitments are not reported on the balance sheet as debt, credit rating agencies view them as having risk characteristics similar to debt. Credit-rating agencies therefore treat the utility's commitments under PPAs as a substitute for debt-financed capital investments in generation capacity in assessing credit risk.

Overall Credit rating agencies agree that PPAs expose the buyer to the financial risk not reflected on the balance sheet as debt (i.e. uncertainty surrounding cost recovery of a long-term commitment). On the positive side, credit rating agencies view PPAs as part of a balanced power supply portfolio approach that allows diversity to procurement, and limits operational risks associated with generation capacity ownership. Understanding Debt Equivalency is therefore important because of its implications for accurately assessing credit risks and related costs associated with long-term contractual commitments such as PPAs.

To achieve comparability between utilities that finance and build generation capacity and those that purchase contractual rights to capacity to satisfy new load, credit rating agencies adjust financial

[1] D. 12-12-034, page 33.

measures to incorporate PPA fixed obligation even though these obligations are not shown as liabilities on the balance sheet. More specifically credit rating agencies have developed procedures for calculating Debt Equivalency and imputing its impact on financial ratios used to measure a utility's creditworthiness.

The financial risk resulting from a large portfolio of PPAs could lead to a credit rating downgrade. The weakened credit ratings, in turn, affect utilities' cost of debt and equity assessed by financial markets. Therefore PPAs or other types of debt equivalent obligations might affect a utility's overall cost of capital.

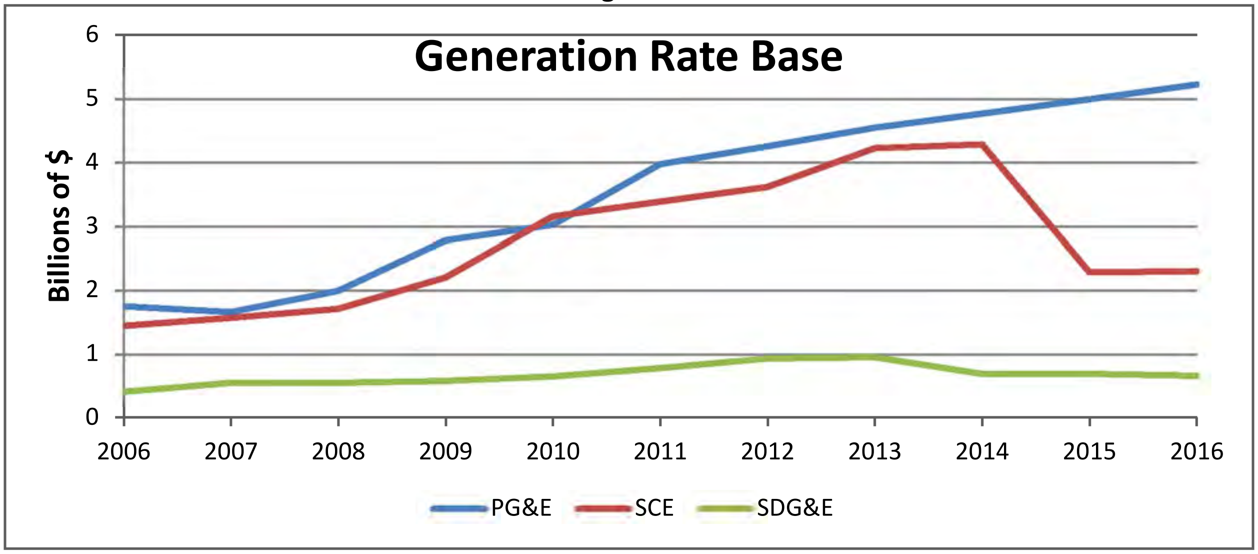
In addition to impacting utilities cost of capital, from investors' perspective, PPAs may limit a utility's ability to grow earnings. The traditional rate-base/rate of return regulatory model provides powerful incentives for utilities to build generation. In rate of return regulatory model utilities earn a return on rate base, which primarily consist of plant in service less accumulated depreciation. Cost of service regulation allows utilities the opportunity to earn a return on utility own generation (UOG) but does not allow utilities to earn a return on PPA. Therefore, from an investors' perspective by limiting a utility's ability to grow rate base, PPAs limit a utility's ability to grow earnings.

In other words, PPAs by replacing UOG restrict the total amount of allowable profits, which in turn might impact how investors view the utility's stock price. Regulators can consider addressing utilities bias to own generation rather than purchase power by developing a performance based mechanism to offset this bias.

Utilities in California have transitioned from owning and operating most of their electric generation needs to purchasing generation from other parties under PPAs. The substantial increase in the number of procurement transactions has dampened utilities investment in generation. The question is whether that has also limited their abilities to grow earnings.

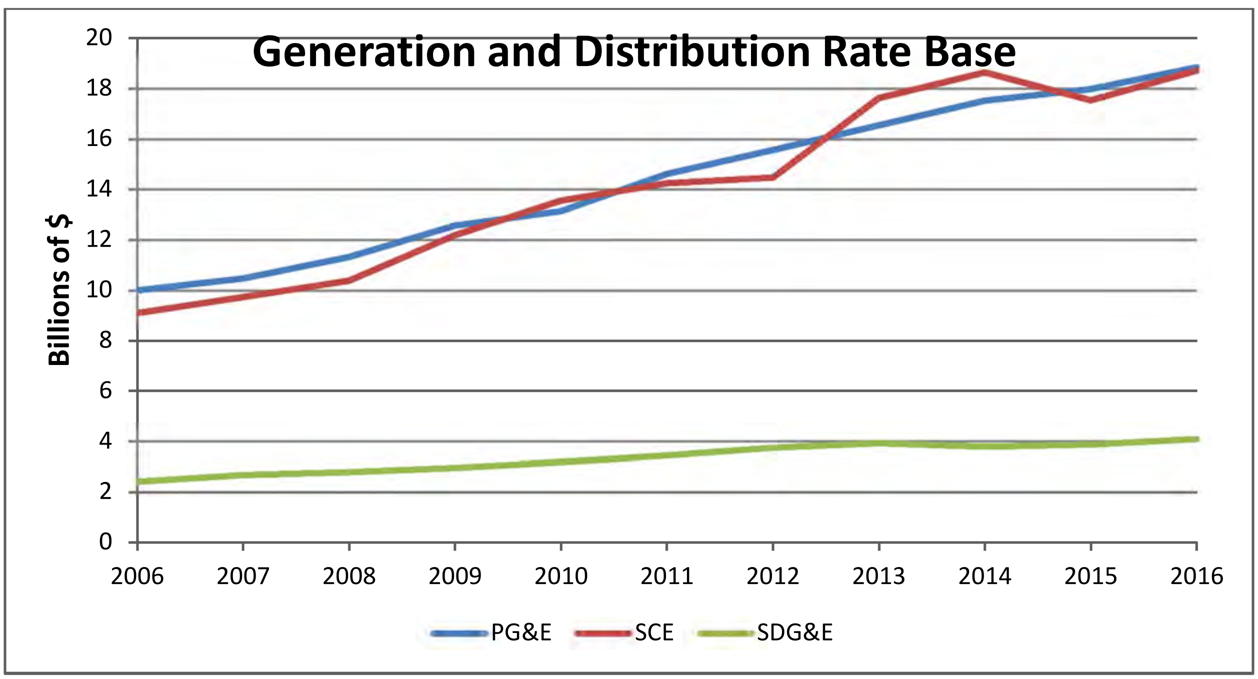
Figure 1 shows PG&E, SCE and SDG&E's generation rate base overtime. As the Figure illustrate for PG&E generation rate base has been increasing overtime. But for SCE and SDG&E generation rate base has declined overtime. The decline for SCE is especially significant. However the decline in the generation rate base for SCE and SDG&E has been more than offset by the growth in distribution rate base. As Figure 2 illustrates when electric distribution rate base is added to generation rate base the trend is upward sloping for all three major IOUs in California. In Figure 3 the total electric rate base, which includes transmission rate base, has a steeper upward slope for all the major IOUs in California.

Figure 1



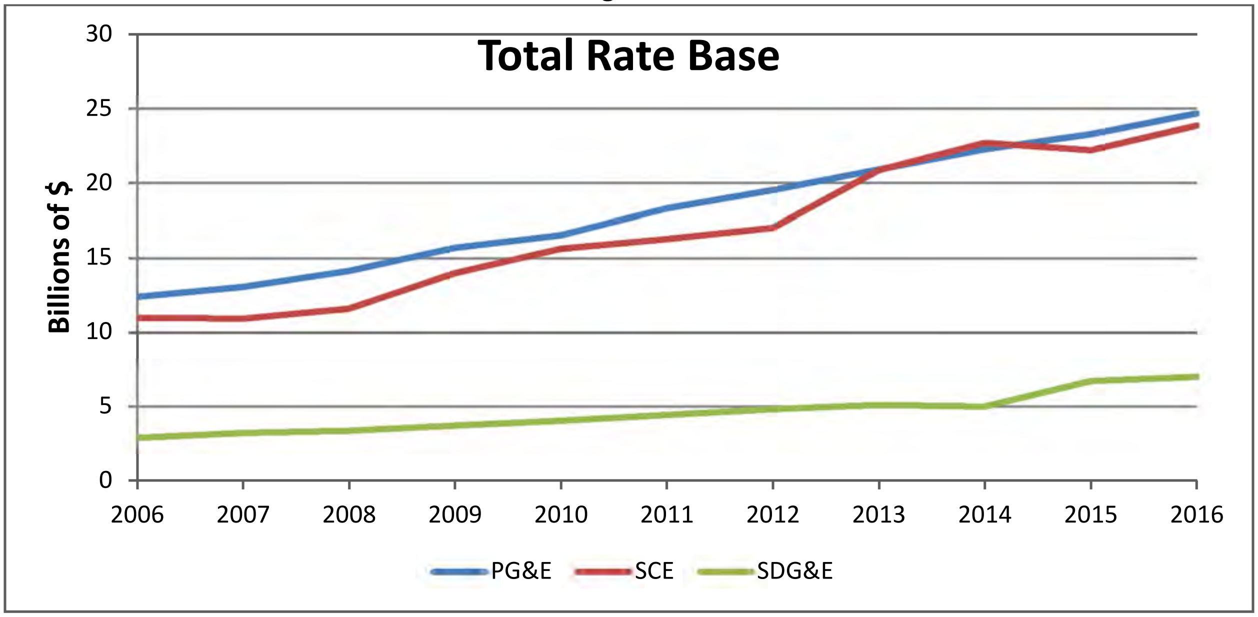
Based on data collected by the Energy Division

Figure 2



Based on data collected by the Energy Division

Figure 3



Based on data collected by the Energy Division

The following sections will present credit rating agencies' view on Debt Equivalency. More specifically the following sections will present credit rating agencies' view on the following threshold issues:

- How to measure Debt Equivalency,
- How to calculate Debt Equivalency impact,
- What types of adjustment are needed to mitigate the impact of PPAs.

III. How Debt Equivalence is measured?

All three credit rating agencies, S&P, Moody's, and Fitch Ratings (Fitch), assign Debt Equivalency to capacity payments. All three also agree that PPA exposes buyer to the uncertainty surrounding cost recovery of long-term financial commitments not reflected as debt on the balance sheet. Among the three, S&P places the greatest emphasis on Debt Equivalency and has published detailed methodology.

The Debt Equivalency value is calculated as the present value of the capacity payment, discounted at the utility's average cost of debt, and multiplied by a risk factor. The risk factor is intended to reflect the probability that PPA costs will be fully recovered in rates and varies depending on state-specific regulatory or legislative cost-recovery mechanisms. The present value of the capacity payment may also be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio. Where those mitigating factors are present, the risk factor can reduce the imputed debt equivalence amount.

Credit rating agencies have different methodologies for calculating a risk factor. Next credit rating agencies' methodology for estimating a risk factor will be explained.

1. Risk Factor

Credit rating agencies apply different methodology for estimating a risk factor. Risk factors can range between 0% and 100%. A 100% risk factor would signify that substantially all risk related to cost recovery of contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity.

For utilities S&P typically assigns risk factors between 0% and 50% based on different factors including; (1) regulatory environment that can range from favorable to unfavorable, (2) mechanisms to recover costs such as automatic recovery (can vary depending on whether recovery takes place in a timely manner, with more certainty and is complete) or legislative mandate, (3) counterparty risk based on performance history and credit quality.

Recovery mechanism policies which provide assurances of cost recovery mitigate the credit risk impact of debt equivalency for S&P. In rate cases, risk factor assigned by S&P can have a value around 50%. With the increased likelihood of recovery under power purchase adjustment mechanism for all prudent PPA costs, a risk factor of 25% is employed. And in case of legislative mandate risk factor can have a value between 0% and 15%.[2] For utilities in California where cost recovery is under power purchase adjustment mechanisms for all prudent PPA costs, S&P uses a risk factor equal to 25%.

Moody's does not apply a formula. Instead Moody's conducts qualitative assessment of inherent risk to determine the degree to which company's financial flexibility is affected by PPAs. Therefore, Moody's approach is more subjective. "In certain cases, Moody's would not impute any debt and in other cases consider PPAs as a positive risk mitigation factor. Moody's recognizes that PPAs have been used by utilities as a risk management tool. Thus, it will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Moody's looks at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations."[3] Regulatory assurances for Moody's can result in risk factor equal to 0%. For California, Moody's does not always assign debt equivalency due to high probability of cost recovery.

Fitch assigns risk factor, which can range between 0 and 100%, based on (1) PPA cost relative to market (market to market value is calculated based on forecast), (2) likelihood of cost recovery taking into account lags in regulatory recovery and probability of disallowances, (3) counterparty credit quality i.e. risk of seller's default. Fitch focuses on out-of- money positions with low cost recovery prospects. For California, Fitch does not always assign debt equivalency due to high probability of cost recovery.

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[2] Key Credit Factors for the Regulated Utilities Industry, Standard & Poor's, November 19, 2013.
[3] D12-12-034

In the next section S&P methodology for estimating the impact of Debt Equivalency on credit ratings will be explained.

IV. S&P Methodology for estimating the impact of Debt Equivalence

To discuss the process of assigning Debt Equivalence to capacity payments, in this section, S&P methodology is explained. S&P places the greatest emphasis on Debt Equivalence of all the rating agencies and has published a detailed methodology.

The first step involves an estimation of the annual capacity payments that have to be made under the contract. S&P does not capitalize the energy component of the contract because of the need to equate the comparison between utilities that buy vs. build, i.e. S&P does not capitalize utility fuel contracts. In contracts where the capacity and energy components is not broken out separately, S&P's old methodology for estimating capacity payment was based on 50% of total payment. S&P's new methodology is based on implied capacity payment. Implied capacity payment is estimated by identifying an implied capacity price within an all-in energy price. The implied capacity payment, which is expressed in dollars per kilowatt-year, is found by multiplying implied price by the number of kilowatts under contract.[4]

Second, S&P re-characterizes a PPA obligation as the creation of an asset financed with debt. The implied creation of the asset represents the ownership-like attributes of the contracted PPA. S&P then estimates imputed debt, imputed interest and imputed depreciation associated with the implied creation of the asset.

Imputed debt increases the debt reported on the balance sheet by the present value of the stream of capacity payments multiplied by the risk factor. Equity is not adjusted because the implied creation of the asset is financed with debt. Total assets, as reported for financial accounting purposes, are increased for the implied creation of the asset by the amount of implied debt. S&P estimates an imputed interest associated with the imputed debt. Imputed interest expense increases income statement interest expense by the amount of imputed debt multiplied by the average cost of debt.

Furthermore S&P estimates an imputed depreciation associated with the implied creation of the asset that tempers the impact of PPAs on cash flow measures. The imputed depreciation is estimated as risk factor multiplied by capacity payment minus imputed interest expense. The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).

[4] Standard and Poor's Methodology for Imputing Debt for U.S. Utilities Power Purchase Agreements, Standard & Poor's, May 7, 2007.

Third, the imputed debt, Interest and depreciation are used to adjust on a pro forma basis the respective amounts reported for accounting purposes on the balance sheet and income statement. S&P uses the information from the pro forma financial statements to estimate financial ratios that are employed as part of the analysis to assign credit ratings. More specifically to evaluate default risk, S&P uses adjusted financial statements to calculate the following financial ratios:

1) Debt as a percentage of Total Capital,
2) Funds from Operations (FFO) to Debt,
3) FFO Interest Coverage = (FFO+ Interest Expense)/Interest Expense.

FFO is defined as net Income plus depreciation plus other net cash from operations plus imputed depreciation expense.

The adjusted financial ratios impact default risk or creditworthiness of the utility. Table 1 shows financial ratio guidelines that S&P uses for A, A- and BBB- rated utilities. A credit rating below BBB- is considered not investment grade. For S&P the link between Debt Equivalency and credit worthiness is direct since S&P relies primarily on quantitative factors.

Table 1: S&P Utility Group Financial Targets

Indicative Ratings	(FFO/Debt) %	(FFO/Interest)	(Total Debt/Capital) %
A	40-60	4.0-6.0	25-40
A-	25-45	3.0-4.5	35-50
BBB-	10-30	2.0-3.5	45-60

However, given the range of financial guidelines in Table 1, even for S&P the link depends on where the utility is positioned in its' ranking bracket. In other words, debt equivalence is more likely to have a direct impact in S&P approach when the financial ratios are closer to the minimum of the range. For example, if a utility has a BBB- financial risk indicator based upon its financial ratios, a change from a 58 percent debt-to-capital to one with 62 percent places the utility in the "Highly Leveraged" financial risk indicator category for that ratio and will likely results in a credit downgrade.

It should be pointed out that the link between Debt Equivalency and credit ratings for Moody's is indirect. Moody's resolves the rating implications on the case by case basis with reference to both qualitative and quantitative factors.

V. S&P Mitigation Methodology

S&P has developed three approaches for addressing mitigation of debt equivalency:

1) Adjusting utility's capital structure (equity ratio) to mitigate the impact of PPAs,
2) Adjusting utility's cost of equity (ROE) to mitigate the impact of PPAs,
3) Adjusting the PPA offers from third parties to reflect the impact PPAs. More specifically, to offset the negative effects of imputed debt, collect a return on amount of imputed equity as an adder to the PPA bids.

S&P has published its detailed methodology on Debt Equivalence mitigation. In what follows, the three mitigating methods developed by S&P are explained by way of an example of a company ABC. Assume ABC enters into a 30-year PPA for 1.5 million MWh at annual capacity payments of $50 million. Also assume ABC's risk factor is 25%.

Table 2 show capital structure and cost of capital (weighted average cost or WACC) of the company prior to entering the PPA contract. Total asset or rate base, $1000 million, consists of 50% debt and 50% equity. ABC's cost of debt is 5% and its' cost equity is 10%.

Table 2: Regulated Capital Structure and Cost of Capital Prior to PPA

	Amount ($)	%	Cost	WACC
Debt	$500	50%	5%	2.5%
Equity	$500	50%	10%	5.0%
Total	$1000	100%		7.5%

To incorporate the impact of Debt Equivalency, S&P imputes debt, interest and depreciation in the following manner:

Present Value of capacity payment is equal to $768.6 million ($\sum_{t=1}^{30} \$50/(1+5\%)^t$),
Imputed debt is equal to $192.2 m ($768.6 x 25%),
Imputed interest is equal to $9.6 m ($192.2 x 5%),
Imputed depreciation is equal to $2.9 million ($50 x 25% - $9.6)

Table 3 shows the capital structure post-PPA contract including the impact of Debt Equivalency.

Table 3: Adjusted Capital Structure Including Imputed Debt Post PPA

	Amount ($)	%
Debt	$692	58%
Equity	$500	42%
Total	$1192	100%

Comparison of Table 3 with Table 2 shows that inclusion of Debt Equivalency increases the percentage of debt in the capital structure by 8 percent.

1. Mitigation Method One: Increase the amount of equity in the rate base.

To restore the original capital structure, ABC issues new equity in the amount of $96 million and recalls debt in the amount of $96 million. Table 4 shows the capital structure after the mitigation with the imputed debt. As Table 5 shows this method of mitigation restores the original capital structure ratios (50% debt, 50% equity ratio) post-PPA contract.

Table 4: Capital Structure after Mitigation Including DE

	Amount ($)	%
Debt	596	50%
Equity	596	50%
Total	1192	100%

Table 6 shows company ABC actual capital structure and cost of capital post-PPA contract excluding the imputed debt. As Table 5 shows this method by increasing the percentage of more expensive type of capital, common stocks, and reducing the percentage of less expensive type of capital, debt, increases cost of capital.

Table 5: Capital structure and WACC post-PPA contract excluding DE

	$	%	Cost	WACC
Debt	404	40.40	5%	2.02%
Equity	596	59.60	10%	5.96%
Total	1000	100%		7.975%

Comparison of Table 5 with Table 2 demonstrates the impact of this particular mitigation effort on cost of capital. Cost of capital increases by $4.75 million, which is the difference between the pre-PPA and post-PPA WACC times total asset or rate base, $1000, ((7.975%-7.5%)*1000 = $4.75).

Table 6 shows the impact of the mitigation effort on financial ratios S&P employs to assign credit ratings. The mitigation effort fully restores debt ratio and EBIT Interest coverage ratio and partly restores FFO/Interest, and FFO/Debt ratios. EBIT Interest coverage, which reflects how well interest charges are covered by operating income, is another important financial ratio. However the restoration is accomplished at a cost, since it is expensive to issue equity.

Table 6: Ratios Before and After PPA

	Before PPA	With PPA No Mitigation	With PPA & Mitigation
Debt/Capital	50%	58%	50%
FFO/Total Debt	0.25	0.18	0.22
FFO/Interest	6.00	4.70	5.45
EBIT/ Interest	3.20	2.67	3.10

2. Mitigation Method Two: Increase the allowed ROE such that pre-PPA WACC is equal to post-PPA WACC

In Table 2 the pre-PPA contract cost of capital (WACC) is 7.5%. To restore cost of capital (WACC) with imputed debt included in capital structure, as Table 7 demonstrates, the allowed return on equity has to increase to 10.95%.

Table 7
Adjusted Capital Structure Reflecting Imputed Debt and Constant WACC

	$	%	Cost	WACC
Debt	692	58	5%	2.9%
Equity	500	42	10.95%	4.6%
Total	1192	100		7.5%

Table 8 shows company ABC actual capital structure and cost of capital after the increase in return on equity without the imputed debt. As Table 8 shows, this method of mitigation increases cost of capital (from 7.5% to 7.975%) post-PPA contract.

Table 8: Capital Structure without Imputed Debt at Higher ROE

	$	%	Cost	WACC
Debt	500	50	5%	2.5%
Equity	500	50	10.95%	5.475%
Total	1000	100		7.975%

Comparison of Table 8 with Table 2 demonstrates the impact of this particular mitigation effort on cost of capital. Cost of capital increases by $4.75 million, which is the difference between the pre-PPA and post-PPA return on equity times the amount of equity in the rate base, $500, ((10.95%-10%)*500 = $4.75).

Table 9 shows the impact of the mitigation effort on financial ratios S&P employs to assign credit ratings. The mitigation effort does not fully restore any ratios. Therefore this method of mitigation is not sufficient for utilities with low credit ratings. However, this mitigation method, by increasing the return on equity, does compensate shareholders for the increased risk of Debt Equivalency.

Table 9: Financial Ratios Before and After PPA

	Before PPA	With PPA No Mitigation	With PPA & Mitigation
Debt/Capital	50%	58%	58%
FFO/Total Debt	0.25	0.18	0.18
FFO/Interest	6.00	4.70	4.70
EBIT/Interest	3.20	2.67	2.67

Table 10 contrasts the first two mitigation methods. Although both methods result in equal amount of increase in revenue requirement, the first method is more expensive since it also involves transaction or floatation cost for issuing common stocks. Floatation cost is what investment banks charge to underwrite securities. Floatation cost mainly depends on the firm's risk and the particular type of capital being issued. Floatation cost is highest for common stocks.

Table 10: Method One vs. Method Two

	Method 1 Adjust ROE	Method 2 Adjust Equity Ratio
WACC	**7.98%**	**7.98%**
ROE	**10%**	**10.95%**
Revenue Requirement	**$4.75 m**	**$4.75 m**
Transaction Costs	**Present**	**Avoided**
Debt/Capital	**Restored**	**Not Restored**
FFO/Debt	**Partially Restored**	**Not Restored**
FFO/Interest	**Partially Restored**	**Not Restored**

3. **Mitigation Method Three**: Impute new equity to offset imputed debt, collect this via an adder to the PPA bid.

In this mitigation method the utility collects an additional return on equity through an adder to the PPA bid. The additional return is based on the imputed equity required to offset imputed debt. Imputed equity, equity return, and contract adder are calculated as:

Imputed Equity = Imputed Debt (Equity/Debt),*
*Equity Return = Imputed Equity*ROE,*
Contract adder = Equity Return/MWh per year

Table 11 shows the compensating equity, compensating ROE, and contract adder over the life of the contract using the PPA in our example. As Table 11 reflect the contract adder declines, as present value of capacity payment and imputed debt decline overtime. In the first year of the contract the present value of capacity payment is $768.6, imputed debt and compensating equity are both $192.16 (debt to equity ratio is one), compensating ROE is $19.22 ($192.16*10%), and contract adder is $12.81 per MWh ($19.22/1.5 MWh).

The amount of compensating equity and return, in this method of mitigation, depends on the choice of ratio to restore. In other words, the company will have to issue more or less equity depending on which ratio is targeted. However, using this mitigation method, the debt ratio (debt/total capital) cannot be restored since equity is not actually issued.

The direct impact of this mitigation method is to compensate shareholders for the increased risk of Debt Equivalency. However this method is more expensive than the other two methods. The present value of contract adder over the life of the contract is $153.33 (using cost of debt as the discount rate). In contrast the present value of the total cost for the other two methods is $76.67.Therefore this method is more appropriate for a utility with low credit rating.

Table11: Method Three

Year	PV of Capacity Payment ($)	Imputed Debt $	Compensating Equity $	Compensating ROE $	Contract Adder ($/MWh)
1	768.6	192.16	192.16	19.22	12.81
2	757.1	189.26	189.26	18.93	12.62
3	744.9	186.23	186.23	18.62	12.42
4	732.2	183.04	183.04	18.30	12.20
5	718.8	179.69	179.69	17.97	11.98
6	704.7	176.17	176.17	17.62	11.74
7	689.9	172.48	172.48	17.25	11.50
8	674.4	168.61	168.61	16.86	11.24
9	658.2	164.54	164.54	16.45	10.97
10	641.1	160.26	160.26	16.03	10.68
11	623.1	155.78	155.78	15.58	10.39
12	604.3	151.07	151.07	15.11	10.07
13	584.5	146.12	146.12	14.61	9.74
14	563.7	140.93	140.93	14.09	9.4
15	541.9	135.47	135.47	13.55	9.03
16	519	129.75	129.75	12.97	8.65
17	494.9	123.73	123.73	12.37	8.25
18	469.7	117.42	117.42	11.74	7.83
19	443.2	110.79	110.79	11.08	7.39
20	415.3	103.83	103.83	10.38	6.92
21	386.1	96.52	96.52	9.65	6.43
22	355.4	88.85	88.85	8.88	5.92

23	323.2	80.79	80.79	8.08	5.39
24	289.3	72.33	72.33	7.23	4.82
25	253.8	63.45	63.45	6.34	4.23
26	216.5	54.12	54.12	5.41	3.61
27	177.3	44.32	44.32	4.43	2.95
28	136.2	34.04	34.04	3.4	2.27
29	93	23.24	23.24	2.32	1.55
30	47.6	11.9	11.9	1.19	0.79
Total					243.79

Furthermore for PPA contracts that pricing is stated as a single, all-in energy price, S&P has developed a separate methodology. For contracts with all-in energy prices S&P first calculates an implied capacity price that is supposed to fund the recovery of the supplier's capital investment. S&P uses the implied capacity price, stated as $/kW, to calculate the implied capacity payment associated with the PPA. The implied capacity payment is found by multiplying the capacity charge, $/kW, by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, S&P adjust the kilowatts under contract to reflect the anticipated capacity that the resource is expected to achieve.

Based on the discussion in this section it can be concluded that no perfect quantitative solution to the problem of PPA-related risk transfer and imputed debt exist. The next section will examine how the issue of Debt Equivalency has been addressed by the Commission.

VI. How Debt Equivalence has been addressed by the Commission?

Utilities have raised the issue of Debt Equivalency in both Cost of Capital and Long-term Procurement proceedings. The Commission long standing position is that cost recovery treatment of Debt Equivalency should be addressed in Cost of Capital proceeding. The Commission has also been considering the issue of Debt Equivalency among other factors in the selection of new supply in Long-term Procurement proceeding. In what follows Commission approach to Debt Equivalency in Long-term Procurement and Cost of Capital proceedings is discussed in more detail.

1. Long-term Procurement Proceeding

Debt Equivalence became an issue in the 2001 long-term procurement proceeding (i.e., a rulemaking proceeding (R.01-10-024) on establishing policies and cost recovery mechanisms for generation procurement and renewable resource development). In that proceeding, SCE requested that the Commission should increase its equity ratio to counter the rating decline that it was expecting to result as it takes on additional power contracts and long term commitments. Although debt equivalence was addressed in the discussion portion of an interim decision, D.04-01-050, that issue was deferred to the cost of capital proceeding where the energy utilities were expected to present detailed evidence about the treatment of debt equivalence by the rating agencies.

The issue of Debt Equivalency was litigated in the 2004 Long-term Procurement Proceeding (LTPP), R.04-04-003. In that proceeding SDG&E, SCE, and PG&E recommended that Debt Equivalence be adopted in procurement to ensure the resource acquisition process going forward takes into account the impact of Debt Equivalence. PG&E, in particular, had proposed that the impact of Debt Equivalence on the utilities' financial condition should be addressed in the cost of capital proceeding, but that in R.04-04-003 the Commission should establish that the Debt Equivalence impacts of new long-term commitments may be considered in the contract selection and approval process.

In 2004 LTPP decision, D.04-12-048, the Commission recognized that Debt Equivalence is a real economic cost borne by an IOU when it enters into a PPA, and can have an impact on a utility's credit rating. In D.04-12-048 the Commission ruled that Debt Equivalence has to be considered by IOUs and/or independent evaluator in the contract selection and approval process. D.04-12-048 based the methodology for evaluating individual PPAs bids on S&P methodology. However the Commission found the 30% S&P risk factor too high to be reasonable and fair to all PPAs. Therefore the Commission required the utilities to employ a modified S&P methodology of 20% risk factor for all PPA bids.

D.04-12-048 also found that "DE was a subjective factor based on the credit rating agencies' perceived risk associated with PPAs, that the credit agencies ' views are not static and can change with respect to particular PPA during the term of the PPA and that the imputed costs for existing PPA will be reduced as the regulatory climate in California improves."

In 2006 LTPP the Commission eliminated the bid adder for PPAs and the 2006 LTPP decision, D.07-12-052, instructed the utilities to raise the Debt Equivalence issue in Cost of Capital proceedings. More specifically, D.07-12-052 found that the Commission's approach to Debt Equivalence goes against the Commission's stated goal of promoting head-to head competition between PPAs and UOG by creating a disparity between the treatment of PPAs and utility-owned projects in the procurement process.

In response to D.07-12-052, the major utilities filed Petition for Modification (PFM) asking the Commission to revisit its' findings. After deliberation of the competing positions, the Commission ruled it is appropriate in some cases for the IOUs to recognize the effects of Debt Equivalence in their bid evaluation processes. More specifically, it allowed the use of 20% debt equivalence debt equivalence adder in head-to-head competition between PPAs but because of the complexity of the risk-related pros and cons associated with PPA versus UOG ownership it continued to prohibit the use of the debt equivalence adder in solicitations that include both PPA and UOG.

The Commission approach to debt equivalency in LTPP can have significant impact on competitive bids. The Commission has been cognizant of the fact that the inclusion of a debt equivalency adder to competitive bids can preclude new PPAs, despite their desirable consumer benefits such as economic efficiency, improved reliability, and environmental performance. For example an issue that came up in 2006 LTPP concerns the Renewable Portfolio Standard requirements and the impact of Debt Equivalence on renewables costs. In response, the Commission ruled that it is important to ensure that in head-to-head competition, the use of the Debt Equivalence adder does not disadvantage bids for renewable and innovative low-carbon resources that may have higher capital costs than traditional gas-fired generators.

The Commission approach to Debt Equivalence in Long-term Procurement Proceeding has not changed since D.07-12-052. IOUs are still allowed to use Debt Equivalency adders when evaluating PPA vs. PPA but are instructed not to use Debt Equivalence adders when evaluating PPA vs. UOG.

2. Cost of Capital Proceedings

IOUs raised the issue of Debt Equivalence for the first time in a Cost of Capital proceeding in 1993 (D.92-11-047). In that proceeding, to deal with the impact of Debt Equivalency, utilities requested an adjustment in capital structure by shifting from debt to equity. The Commission rejected utilities request but set a standard for addressing the issue of Debt Equivalency. The Commission recognized that Debt Equivalency may impact utilities' credit rating and cost of borrowing. The Commission stated that the impact of Debt Equivalency should be considered in authorizing capital structure and ROE.

More recently, in compliance with resource procurement decision D.04-01-050 discussed above, IOUs raised the issue of Debt Equivalence in the 2005 Cost of Capital proceeding. In that proceeding SCE, PG&E, and SDG&E recommended that the Commission establish a Debt Equivalence policy to alleviate their concern that Debt Equivalence is an added cost that needs to be considered both in determining an appropriate capital structure and in making resource procurement decisions. Policy recommendations proposed by the utilities included recognition that the Debt Equivalence adversely impacts credit ratings; use of annual ROE proceedings to update and mitigate Debt Equivalence impacts on credit ratings; adoption of S&P's quantitative debt equivalence formula for use in assessing Debt Equivalence costs in power procurement decision-making proceedings.

In addition in the 2005 Cost of Capital proceeding, to mitigate the effects of debt equivalence, SCE proposed to increase its preferred stock ratio and correspondingly reduce its long-term debt ratio by 4 percent. And SDG&E requested to increase its equity with a simultaneous reduction of debt equal to 65% of the debt equivalence for each individual PPA contract approval by the Commission with the cost associated with the capital structure adjustment rolled into the costs of each PPA.

In 2005 Cost of Capital decision, D.04-12-047, the Commission recognized that Debt Equivalency has been reflected in the utilities' credit ratings since at least 1990 and that debt equivalence associated with PPAs can affect utility financial ratios, credit ratings and capital structure. But the Commission declined to adopt a formal debt equivalence policy based on the opinion that the evidence presented in the proceeding did not substantiate a need to consider the Debt Equivalence issue outside of the traditional ROE assessment of risks. The Commission ruled that as part of their annual ROE applications utilities should include testimony on credit rating and capital structure impacts, including mitigation recommendations of debt equivalence on their PPAs.

Furthermore in D.04-12-047, after assessing the impact of Debt Equivalency on financial ratios that S&P uses to assign credit ratings, the Commission found inclusion of PPA had not adversely impacted utilities' credit ratios or borrowing costs. Nonetheless, the decision approved for SCE a shift from debt to preferred stock arguing that the shift of debt to preferred stock would improve financial metrics, encourage the rating agencies to upgrade SCE's credit status and lower overall long-term costs. But the Commission declined to adopt SDG&E's proposal on the ground that SDG&E had not provided information on the impact of Debt Equivalency on its credit ratings.

Broadly speaking the Commission approach to Debt Equivalency has remained the same as in D.04-12-047. The Commission continues to believe that Debt Equivalence can impact IOUs' credit ratings. In Cost of Capital proceedings the Commission continues to rule that Debt Equivalence should be assessed on a case-by-case basis along with other financial, regulatory and operational risks in setting a balanced capital structure and fair ROE. And in Cost of Capital proceedings the Commission continues to assess the impact of Debt Equivalency on financial ratios that credit rating agencies use to assign credit ratings such as Debt to Total Capital, Funds from Operations to Debt, and Funds from Operations Interest Coverage.

However the strategy of setting a balanced capital structure and fair ROE on case-by-case basis to compensate utilities for the risk of PPAs has been applied differently since 2005 Cost of Capital decision. In what follows, the Commission approach in setting a fair ROE and balanced capital structure in 2006, 2008 and 2012 Cost of Capital decision is first examined. Subsequently the impact of the application of S&P's mitigation methodology on SDG&E's cost of capital and revenue requirement is assessed.

a) Setting a fair ROE in the presence of PPAs

To set an authorized ROE in Cost of Capital proceedings the Commission after considering parties' financial model results, the evidence on market conditions, trends, creditworthiness, interest rate forecasts, additional risk factors, and interest coverage presented by parties, arrives at a base ROE range. Subsequently from the base ROE range found to be just and reasonable, the Commission adopts an authorized ROE. In Cost of Capital proceedings to support major IOUs in California to achieve or maintain investment grade credit ratings, the Commission has been approving an ROE toward the upper end of the ROE range.

In 2006 and 2008 Cost of capital decision the strategy of setting a balanced capital structure and fair ROE on case-by-case basis resulted in increasing the base range of ROE to compensate utilities for the risk of PPAs, in addition to approving an ROE toward the upper end of the ROE range. In contrast in 2012 Cost of capital decision, the approach resulted in choosing an authorized ROE at the top of the ROE range with no additional increases in the base range of ROE.

More specifically in the 2006 Cost of Capital decision, D.05-12-043, , the Commission increased the base range of ROE for SCE, SDG&E, and PG&E by 70 , 50, and 70 basis points, respectively to account for debt equivalence and electric procurement risks. Included in those increased basis points was a premium for perceived regulatory risk in California. In addition for each utility the Commission approved an ROE toward the upper end of the ROE range that was found fair and reasonable.

For example, for PG&E the Commission arrived at a base ROE range of 9.91% to 10.93%. To that range it applied a 70 basis point upward adjustment for electric procurement and regulatory risks resulting in an ROE range of 10.61% to 11.63%. It then adopted a ROE of 11.35% from the upper end of ROE range for test year 2006. Similarly for SCE the Commission arrived at a base ROE range of 9.88% to 10.84%. To that range it applied a 70 basis point upward adjustment for electric procurement and regulatory risks and 28 basis points for inferior credit ratios resulting in an ROE range of 10.86% to 11.82%. It then adopted a ROE of 11.60% from the upper end of ROE range for test year 2006.

Similarly in 2008 Cost of Capital decision, D.07-12-049, to account for debt equivalence and electric procurement risks, the Commission increased the base range of ROE for SCE, SDG&E, and PG&E by 50, 40, and 50 basis points, respectively. The Commission then added 10 basis points premiums to utilities' ROE for regulatory risk as regulatory risk was broken out from Debt Equivalency premium in 2008. In addition for each utility the Commission approved an ROE toward the upper end of the ROE range that was found fair and reasonable.

In contrast in 2013 Cost of Capital Decision, D. 12-12-034, the Commission stated that procurement risk is reflected in the parties' financial modeling results. Therefore the Commission did not increase the base range of ROE to compensate utilities for Debt Equivalency. The Commission considered the utilities credit ratios and how debt equivalency impacts those credit ratios as was done in previous decisions. The Commission also considered cost recovery mechanisms present in California that reduce cost recovery risk such as power procurement commitments, balancing and memorandum accounts and revenue decoupling. To compensate utilities for financial, business, and regulatory risk the Commission authorized an ROE toward the upper end of the ROE range that was found to be fair and reasonable.

The Commission did not grant Debt Equivalency premiums for test year 2013 even though in 2013 Cost of Capital Decision, D. 12-12-034, the Commission acknowledged that there had been an increase in the number of procurement transactions the utilities were entering into.[5] The capital structure and ROE authorized in 2013 decision are effective today. Utilities requested and were granted extensions in 2015, and 2016. Currently utilities have a pending application (A.12-04-015) which if approved will postpone filing of cost of capital applications until 2019.

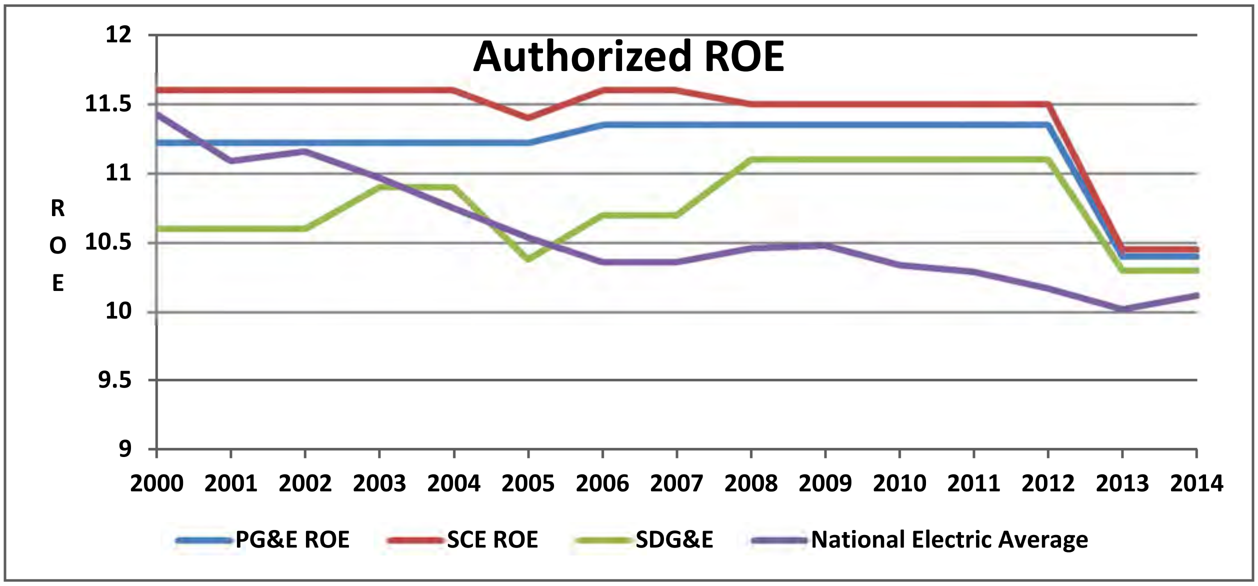
The Debt Equivalency premium that the Commission granted for test year 2006 and 2008 can explain a large part of what has become known as the California Premium. The California premium refers to the

[5] D. 12-12-034, page 33.

finding that the major utilities in California have been earning a return on equity (ROE) higher than the national average. As Figure 4 shows California premium has been more relevant to PG&E and SCE.

An important factor that sets SDG&E apart from the other major utilities in California is the fact that SDG&E has had strong investment grade credit ratings. PG&E and SCE's credit ratings have improved since energy crisis but their credit ratings are still below SDG&E. Therefore SDG&E's authorized ROE quite appropriately has been lower than PG&E and SCE's authorized ROE.

Figure 4



The Debt Equivalency premium granted for test year 2006 and 2008 together covered a 7 year period from 2006 through 2012. Major IOUs in California filed Cost of Capital applications in 2005, 2007 and again in 2012.The Debt Equivalency premium granted for 2006 last through 2007 and the Debt Equivalency premium granted for 2008 lasted through 2012.

Figure 5 contrasts the California premium to the Debt Equivalency premium that the Commission granted for PG&E and SCE. Figure 6 reflects the same contrast for SDG&E. SDG&E's Debt Equivalency premium as Figure 6 shows was lower than SCE and PG&E's Debt Equivalency premium.

As Figure 5 shows for PG&E and SCE the Debt Equivalency premium accounts for close to one-half of their respective California premium. As Figure 6 shows for SDG&E there was no California premium before 2006 and hardly any after 2012. For SDG&E the California premium has been almost entirely due to the Debt Equivalency premium the Commission granted for test year 2006 and 2008.

Figure 5

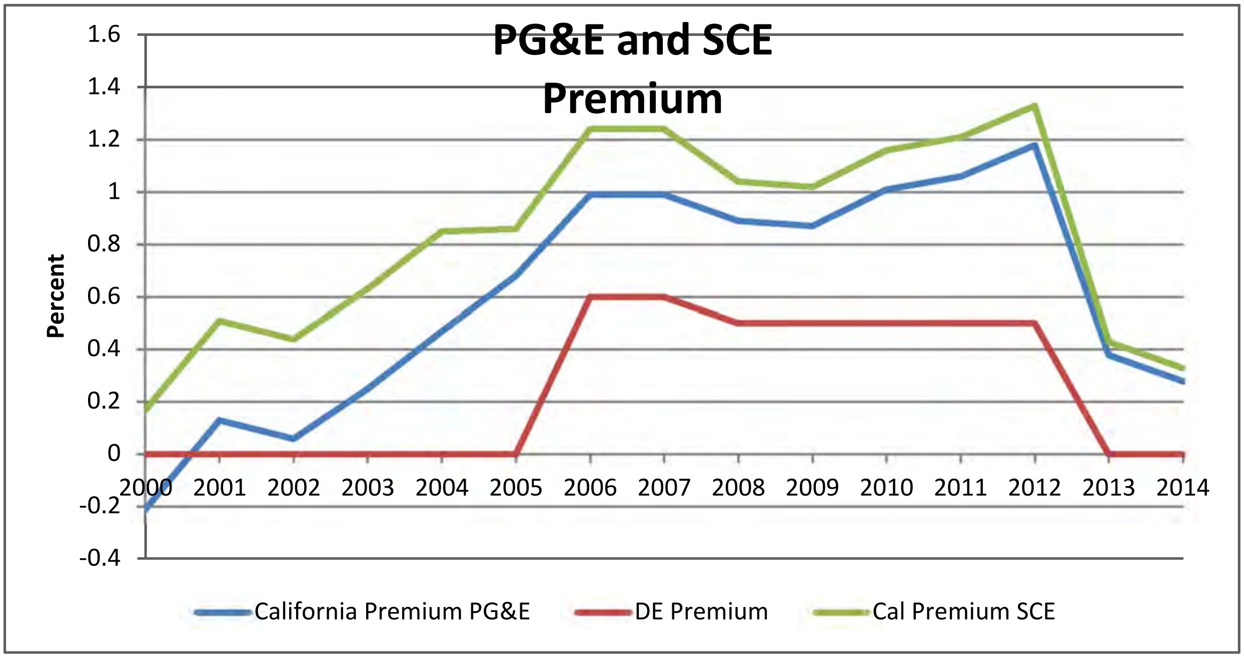
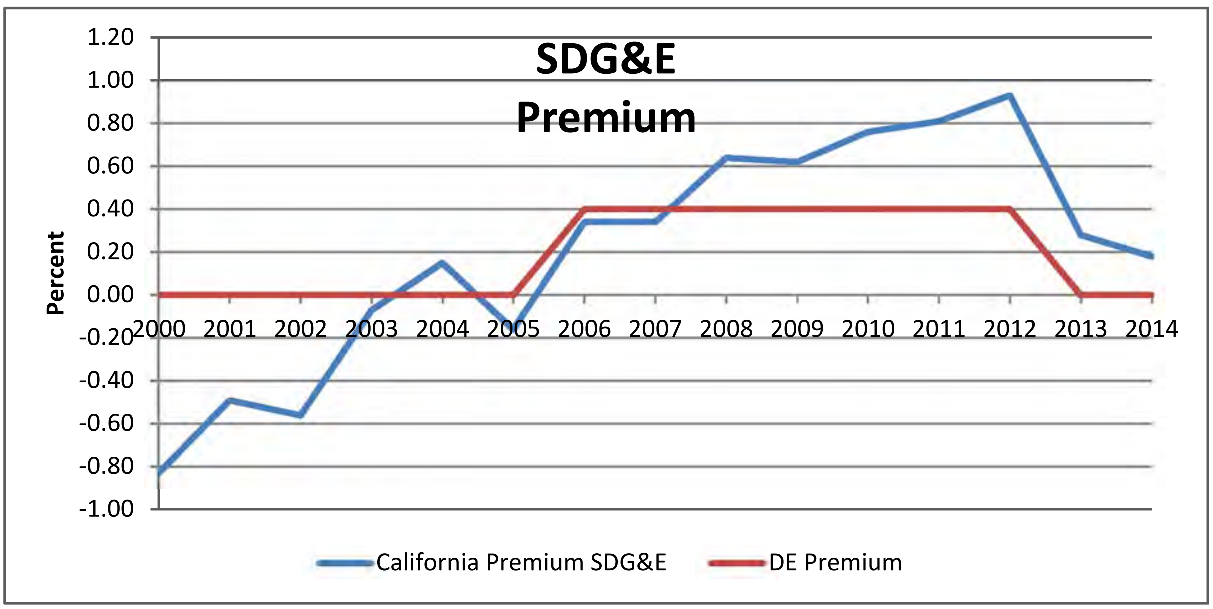


Figure 6



b) Setting a balanced Capital Structure in the presence of PPAs

In addition to proposing adjustments in ROE, SDG&E in 2006 and 2013 Cost of Capital proceeding requested adjustments in capital structure to mitigate the impact of Debt Equivalence. In 2006 Cost of Capital proceeding SDG&E requested a 200 basis points increase in equity ratio with a correspondingly decrease in debt ratio to mitigate the negative effects of debt equivalence. And in 2013 Cost of Capital proceeding SDG&E requested a 300 basis points increase in common equity ratio and a corresponding decrease in preferred stock ratio to mitigate the impact of its' existing, and pending PPAs.[6]

In 2006 Cost of Capital decision, D.05-12-043, the Commission found that SDG&E's credit status and credit ratings do not substantiate a need to mitigate debt equivalence through a change in its authorized capital structure. In contrast in 2012 Cost of Capital decision, D. 12-12-034, the Commission granted SDG&E's request to adjust its' capital structure. However, in granting SDG&E's request the Commission reaffirmed its long standing position of not adopting S&E methodology by restating the disagreement among credit rating agencies in regard to PPAs but stated that the common equity ratio SDG&E is seeking is reasonable because it is similar to SDG&E's ratemaking common equity ratio.[7] In fact in D. 12-12-034 the Commission also granted SoCalGas' request to increase its common equity ratio by 400 basis points based on a similar reasoning.

The Commission by increasing SDG&E and SoCalGas' equity ratio to 52 percent brought their equity ratios more in line with the average equity ratio of utilities nationwide. According to the Regulatory Research Associates, the average equity ratio of utilities in the nation has been on an upward trajectory, increasing from slightly higher than 40 percent for electric utilities and 35 percent for gas utilities in 1980 to slightly over 50 percent in 2014.[8] The increase in the average equity ratio explains why despite a sharp decline in return on equity (ROE) nationwide during the same period (from around 14 percent in 1980 or 16 percent in 1982 to around 8 percent in 2014 for electric utilities), the decline in rate of return (ROR) has been more modest (from around 10 percent in 1980 or 12 percent in 1982 to around 8 percent in 2014 for electric utilities).[9]

Table 12 shows SDG&E's 2013 authorized capital structure, and authorized rate of return (ROR). In Table 12 authorized rate of return is 7.79%.

Table 12

	Ratio	Cost	WACC
Debt	45.25	5.00	2.26
Preferred Stock	2.75	6.22	0.17
Common Equity	52.00	10.30	5.36
Totals	100		7.79

[6] SDG&E's hearing exhibit demonstrated that Standard & Poor's (S&P) had imputed debt equivalence into SDG&E's long-term debt. SDG&E was expecting S&P to increase imputed debt equivalence into its long-term debt partly due to SDG&E's pending purchase power tolling agreements.
[7] The ratemaking capital structure is different from recorded capital structure in that it includes the impact of ratemaking adjustments.
[8] "Regulatory Issues Overview RRA Presentation to NARUC's Gas Committee," SNL Energy, July 13, 2015.
[9] Ibid.

To find the impact of the adjustment in capital structure granted in D. 12-12-034, in Table 13, rate of return is calculated using SDG&E's 2012 authorized capital structure and 2013 adopted cost of debt, preferred and common stock. In Table 13 rate of return WACC is 7.67%.

Table 13

	Ratio	Cost	WACC
Debt	45.25	5.00	2.26
Preferred Stock	5.75	6.22	0.36
Common Equity	49.00	10.30	5.05
Totals	100		7.67

Comparison of Table 12 to Table 13 shows that the adjustment in the authorized capital structure increased SDG&E's rate of return (ROR) by 12 basis points (7.79%-7.67%). Using SDG&E's rate base in 2013, $4137 million,[10] the adjustment in the authorized capital structure resulted in an increase in revenue requirement of around $4.96 million, ((7.79%-7.67%)*4137 = $4.96).[11] The change in authorized capital structure was approximately equivalent to 25 basis points increase in ROE.

Next S&P's mitigation methodology, discussed in earlier sections, will be applied to find the impact of the application of S&P's mitigation method on SDG&E's cost of capital (rate of return) and revenue requirement.

c) Application of S&P's Mitigation Methodology

To investigate the impact of the application of S&P methodology on SDG&E's cost of capital and revenue requirement in what follows S&P's Mitigation Method 1 which calls for increasing the amount of equity in the rate base will be applied first. Subsequently S&P's Mitigation Method 2 which calls for increasing ROE is applied.

The impact of S&P's mitigation methods on cost of capital and revenue requirement can be contrasted to the impact of the adjustments the Commission approved for SDG&E that were discussed in the previous sections.

d) Adjustment to authorized capital structure

Table 14 shows the impact of Debt Equivalency that S&P had imputed and was expected to impute due to SDG&E's pending purchasing power tolling agreements on capital structure. In Table 14, SDG&E's total capital, $8471,[12] and authorized capital ratios in 2012 are used to estimate 2012 capital structure. SDG&E's authorized capital structure in 2012 had more preferred stocks and less debt than SDG&E's

[10] SDG&E's witness, Jesse S. Aragon, testimony in SDG&E's 2016 GRC, page 5.
[11] The figure does not include the required increase in taxes.
[12] SDG&E's witness, Sandra K. Hrna, testimony in 2013 Cost of Capital proceeding, page 6.

recorded capital structure.[13] The impact of Debt Equivalency of the existing and pending PPAs, as Table 14 shows, was to increase the level of debt from approximately 45 to 55 percent.

Table 14

	2012 Authorized Capital Structure %	Estimated 2012 Capital Structure ($)	S&P Imputed	Expected Debt Equivalence	Imputed Capital $	Adjusted Capital %	Change In Capital %
Debt	45.25	3833.13	182	1578	5593.13	54.67	9.42
Preferred Stock	5.75	487.08			487.08	4.76	-0.99
Common Equity	49.00	4150.79			4150.79	40.57	-8.43
Totals	100	8471	182	1578	10231	100	

Source: SDG&E's 2013 Cost of Capital testimony.

To restore the original capital structure, SDG&E had to issue new common stocks and recall outstanding debt. Table 15 shows the capital structure after the mitigation effort with the imputed debt.

Table 15

	Amount ($)	%
Debt	4629.53	45.25
Preferred Stock	588.28	5.75
Common Equity	5013.19	49.00
Totals	10231.00	100

Table 16 shows SDG&E's capital structure and cost of capital post-PPA contract excluding the imputed debt. As Table 16 shows the mitigation effort increases the percentage of more expensive types of capital, common stocks, and reduces the percentage of less expensive type of capital, debt. Common equity increases from 49 percent to 59 percent. Debt decreases from 45 percent to 35 percent.

Table 16

	Amount ($)	%	Cost	WACC
Debt	2970.73	35.07	5.00	1.75
Preferred Stock	487.08	5.75	6.22	0.36
Common Equity	5013.19	59.18	10.30	6.10
Totals	8471.00	100		8.21

[13] The recorded capital structure is different from ratemaking capital structure in that it does not include the impact of ratemaking adjustments.

Comparison of Table 16 to Table 13 demonstrates that the mitigation effort increases revenue requirement by $22.34 million,[14] which is the difference between the pre-PPA and post-PPA cost of capital times rate base, $4137, ((8.21%-7.67%)*4137 = $22.34 million).

e) Adjustments to ROE

In Table 3 the pre-PPA contract cost of capital (WACC) is 7.67%. To restore the weighted average cost of capital (WACC) with imputed debt included in capital structure, as Table 17 demonstrates, the allowed return on equity has to increase from 10.30 percent to 11.44 percent.

Table 17
Adjusted Capital Structure Reflecting Imputed Debt and Constant WACC

	Amount ($)	%	Cost	WACC
Debt	5593.13	54.67	5.00	2.73
Preferred Stock	487.08	4.76	6.22	0.30
Common Equity	4150.79	40.57	11.44	4.64
Totals	10231			7.67

Table 18 shows SDG&E's cost of capital after the increase in return on equity without the imputed debt. As Table 18 shows, this method of mitigation increases cost of capital (from 7.67% to 8.22%) post-PPA contract.

Table 18
Capital Structure without Imputed Debt at Higher ROE

	%	Cost	WACC
Debt	45.25	5.00	2.26
Preferred Stock	5.75	6.22	0.36
Common Equity	49.00	11.44	5.60
Totals	100		8.22

The impact on cost of capital and revenue requirement is similar to the adjustment in capital structure. The increase in revenue requirement is approximately $22.75 million, excluding the required increase in taxes.

The two mitigation methods result in much higher increases in revenue requirement than what the Commission approved. The increase in equity ratio from the application of Method One is 10 percent (from 49% to 59%) and the increase in return on equity from the application of Method Two is 1.14%

[14] The figure does not include the required increase in taxes.

(from 10.30% to 11.44%). The increase in revenue requirement from the application of either method is approximately $22.5 million.

As was discussed before in 2012, the Commission approved a 3 percent increase in equity ratio for SDG&E, which was equivalent to 25 basis increase in return on equity. In addition to compensate utilities for financial, business, and regulatory risk the Commission authorized an ROE toward the upper end of the ROE range that was found to be fair and reasonable. For SDG&E, the Commission arrived at a base ROE range of 9.60% to 10.40%. The Commission then set the test year 2013 ROE at 10.30%, which is 30 basis points higher than the midpoint of the range. Therefore, the two adjustments were equivalent to an increase in return on equity of about 55 basis points. The increase in revenue requirement resulting from the two adjustments was approximately $11 million, excluding the required increase in taxes.

VII. Conclusion

The Commission's long standing position is that the impact of Debt Equivalency on utilities' financial condition should be addressed in Cost of Capital proceeding. In addition in Long-term Procurement proceedings the Commission has been considering the Debt Equivalency impact of new long-term commitments in the contract selection and approval process in some cases.

The Commission preference to address Debt Equivalence in Cost of Capital proceeding appears to be cost effective. Obviously mitigation cost, first and for most, depends on the extent of mitigation. When S&P's mitigation methodology is applied, as was shown in the example above, the mitigation cost is the highest when it is addressed in Long-term Procurement proceeding.

In Cost of Capital proceedings the Commission has acknowledge that rating agencies impute debt from long-term PPAs and incorporate that in their credit analysis. But the Commission has not adopted a comprehensive policy on the cost recovery treatment of Debt Equivalency.

The Commission's approach in Cost of Capital proceedings is partly based on the understanding that S&P always imputes debt but Fitch and Moody's sometimes do not and that S&P methodology should not be over-weighted versus Moody's and Fitch approach. Moody's, in particular, conducts qualitative assessment of PPA risk. Moody's determine the degree to which PPA effect a company's financial flexibility by a qualitative assessment of the inherent risk. Similarly Fitch does not always assign Debt Equivalency to PPA. More specifically Fitch does not assign Debt Equivalency when there is a high probability of cost recovery.

In Cost of Capital proceedings, the Commission has ruled that Debt Equivalence should be assessed on a case-by-case basis along with other financial, business and regulatory risks in setting a balanced capital structure and fair ROE. In addition in Cost of Capital proceedings the Commission continues to assess the impact of Debt Equivalency on financial ratios that rating agencies use to assign credit ratings.

The Commission has applied the strategy of setting a balanced capital structure and fair ROE on case-by-case basis differently over the years. In 2006 and 2008 Cost of capital decision to compensate utilities for the risk of PPAs the Commission granted Debt Equivalency premiums to utilities. The Debt Equivalency premiums that the Commission granted for test year 2006 and 2008 explains a large part of what has become known as California premium.

In 2013 Cost of Capital decision the Commission did not grant Debt Equivalency premiums to utilities. Utilities have not filed Cost of Capital applications since 2012. California premium was contracted in 2013 and has remained low.

Q1.1: Please refer to Brett A. Jerasa's Attachment BAJ-8 (Public). Please provide the S&P and/or Moody's credit ratings reports for each company listed.

Response:

Please see the following documents:

- 45600_OUCC DR01.1_S&P AEP
- 45600_OUCC DR01.1_S&P ALLETE
- 45600_OUCC DR01.1_S&P CMS
- 45600_OUCC DR01.1_S&P DTE
- 45600_OUCC DR01.1_S&P Entergy
- 45600_OUCC DR01.1_S&P Evergy
- 45600_OUCC DR01.1_S&P WEC
- 45600_OUCC DR01.1_S&P Xcel

S&P Global
Ratings

Research

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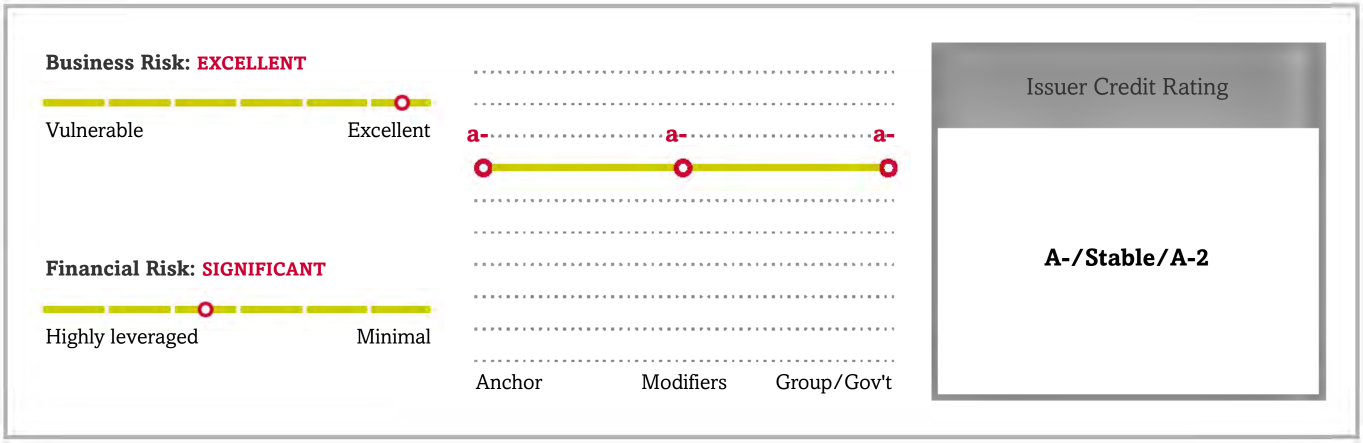
American Electric Power Co. Inc.



Credit Highlights

Overview

Key strengths	Key risks
Mostly lower-risk electric utility holding company.	Elevated capital spending program requires ongoing balanced funding and timely cost recovery.
Large scale of operations with a customer base of about 5.4 million combined with solid geographic diversity with operations in 11 U.S. states.	Significant coal-fired generation remains.
Generally credit-supportive and constructive regulatory frameworks.	Higher operational risk arising from the ownership of the Cook nuclear plant.
Reducing coal-fired generation through retirements and expanding transmission assets.	Financial measures at the lower end of the benchmark range for the financial risk profile, resulting in limited cushion.

Approved North Central Wind rate-based generation investment in Oklahoma is a scalable strategy. American Electric Power Co. Inc.'s (AEP's) investment is credit supportive in that regulators can approve the construction of individual wind farms without authorizing the entire plan. The company achieved regulatory approvals in Oklahoma, Louisiana, Arkansas, and at the Federal Energy Regulatory Commission (FERC). S&P Global Ratings expects AEP to fund these investments in a credit-supportive manner. In addition, these wind farms will help AEP lower its overall carbon dioxide emissions and the proportion of coal-based generation.

The reduction in coal-fired generation aligns with the advancement toward a clean energy future. AEP has a goal of reducing its coal capacity to 24% of its total generation fleet by 2030. The company intends to retire 5,600 MW of coal generation within the next nine years, including the expiration of the lease on Rockport 2. With the rapid retirement of coal plants, AEP plans to replace with wind, solar, and natural gas generation.

Large multistate operations that have constructive regulatory frameworks bolster overall credit quality. AEP is one of the largest electric utilities in the U.S., delivering electricity to about 5.4 million customers across 11 states. The diversity helps mitigate the impact of adverse regulatory decisions or regional economic challenges. The jurisdictions generally have constructive regulatory frameworks that provide for the timely recovery of approved capital expenditures, as well as pass-through fuel cost mechanisms and recovery of various operating expenses.

FERC-regulated transmission investments are credit-enhancing. AEP's most recent capital spending plan calls for higher spending on transmission infrastructure and projects. This should further increase its transmission rate base, providing stable and predictable cash flows through formula-based rates.

Outlook: Stable

The stable outlook on AEP and its subsidiaries reflects the company's improving business risk profile consisting almost entirely of solid regulated utility operations. We expect AEP to generate funds from operations (FFO) to debt 15%-16% through 2021 in our base case scenario.

Downside scenario

We could lower the ratings on AEP and its subsidiaries if the company's financial performance weakens such that FFO to debt is consistently below 14%, or if its business risk increases as a result of ineffective management of regulatory risk or the pursuit of risky nonregulated investments.

Upside scenario

While not likely, we could raise the ratings on AEP and its subsidiaries if the company's financial performance improves, with FFO to debt consistently above 20% while business risk is unchanged.

Our Base-Case Scenario

Assumptions

- Economic conditions in the company's service territories continue to improve modestly, supporting a gradual increase in load growth.
- Operating cash flows strengthen from rate recovery of additional capital and operating costs.
- Capital spending is elevated at $6.1 billion to $7.7 billion per year.
- Common stock dividends average about $1.6 billion annually.
- Negative discretionary cash flow indicates external funding needs.
- Company refinances all debt maturities.

Key Metrics

American Electric Power Co. Inc.--Key Metrics

	2020e	2021f	2022f	2023f
Adjusted FFO to debt (%)	15-16	15-16	15-16	15-16
Adjusted debt to EBITDA (x)	5-5.5	5-5.5	5-5.5	5-5.5
Adjusted FFO cash interest coverage (x)	4.5-5	4.5-5	4.5-5	4.5-5

e--expected. f--forecasted. FFO--Funds from operations.

Base-case projections

- Gross margin benefits from rate recovery mechanisms and transmission formula rates.
- Annual debt to EBITDA averaging about 5x.
- Company uses debt to partly fund negative discretionary cash flow.
- Adjusted FFO to debt in the 15%-16% range, with the outer years strengthening following incremental recovery of costs through rates.

Company Description

Columbus, Ohio-based AEP is a holding company of electric utilities that serve about 5.4 million customers in 11 states.

Peer Comparison

We consider AEP similar to peers Berkshire Hathaway Energy Co., Duke Energy Corp., WEC Energy Group Inc. (WEC), and Xcel Energy Inc. They operate across multiple states, have many customers, and own electric generation, including coal-fired plants. Like AEP, all peers except WEC own nuclear generation. Regulated electric transmission play a part in each company's strategy

AEP's financial measures has resulted in the company being in the middle of its peers. These companies' utilities all operate generally supportive regulatory environments with various rate mechanisms for cost recovery.

Table 1

American Electric Power Co. Inc.--Peer Comparison

Industry Sector: Electric	**American Electric Power Co. Inc.**	**Berkshire Hathaway Energy Co.**	**Duke Energy Corp.**	**WEC Energy Group Inc.**	**Xcel Energy Inc.**
Ratings as of Jan. 11, 2021	A-/Stable/A-2	A/Stable/A-1	A-/Negative/A-2	A-/Stable/A-2	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2019--				
(Mil. $)					
Revenue	15,440.0	19,844.0	24,982.4	7,523.1	11,529.0
EBITDA	5,712.4	7,503.3	11,668.4	2,727.6	4,268.3
Funds from operations (FFO)	4,601.9	6,466.9	9,957.8	2,250.1	3,544.6
Interest expense	1,292.9	2,046.4	2,906.4	541.3	842.7
Cash interest paid	1,104.4	1,886.4	2,361.6	502.4	776.7
Cash flow from operations	4,387.9	6,287.9	8,237.8	2,401.9	3,318.6
Capital expenditure	6,078.0	7,305.9	10,963.0	2,302.9	4,259.5
Free operating cash flow (FOCF)	(1,690.1)	(1,018.0)	(2,725.2)	99.0	(940.9)
Discretionary cash flow (DCF)	(3,060.6)	(1,311.0)	(5,420.1)	(796.2)	(1,731.9)

Table 1

American Electric Power Co. Inc.--Peer Comparison (cont.)

Industry Sector: Electric	American Electric Power Co. Inc.	Berkshire Hathaway Energy Co.	Duke Energy Corp.	WEC Energy Group Inc.	Xcel Energy Inc.
Cash and short-term investments	449.5	1,068.0	311.0	37.5	248.0
Debt	29,754.0	44,684.5	63,188.3	13,145.8	20,457.2
Equity	20,783.9	32,578.0	47,470.0	10,489.4	13,239.0
Adjusted ratios					
EBITDA margin (%)	37.0	37.8	46.7	36.3	37.0
Return on capital (%)	6.5	6.4	6.3	7.6	7.2
EBITDA interest coverage (x)	4.4	3.7	4.0	5.0	5.1
FFO cash interest coverage (x)	5.2	4.4	5.2	5.5	5.6
Debt/EBITDA (x)	5.2	6.0	5.4	4.8	4.8
FFO/debt (%)	15.5	14.5	15.8	17.1	17.3
Cash flow from operations/debt (%)	14.7	14.1	13.0	18.3	16.2
FOCF/debt (%)	(5.7)	(2.3)	(4.3)	0.8	(4.6)
DCF/debt (%)	(10.3)	(2.9)	(8.6)	(6.1)	(8.5)

Source: S&P Global Ratings.

Business Risk: Excellent

We base our assessment of AEP's business risk profile on the very low risk of the regulated utility industry and the company's mostly lower-risk, rate-regulated operations that provide electricity, an essential service. Although in 11 states, the company's operations in Ohio, Texas, Virginia, and West Virginia represent the majority of consolidated revenues. AEP has reached largely constructive regulatory outcomes in the jurisdictions where it operates, ensuring some cash flow stability over the next few years. AEP is investing in transmission projects, a trend that is likely to continue, providing support to credit quality through cash flow diversity and further regulatory diversification.

Quality of service territories varies, but many are in stable and diverse economies. They collectively benefit from broad diversity that mitigates the effect of severe weather and local economic conditions. AEP also benefits from a diverse set of customers, which provides stability against lower usage by any particular class, generating the bulk of revenues from residential, commercial, and wholesale customers with a lower contribution from more volatile industrial customers.

AEP's generation fleet benefits from low-cost and efficient operations leading to competitive customer rates. Also, AEP has been lowering its historically high reliance on coal-fired generation through plant retirements and sales, bringing the company's coal-fired capacity at year-end 2020 down to an expected 12,100 megawatts (MW), over 50% lower than in 2010. In addition to reducing air emissions from generation assets, retiring coal capacity results in the company avoiding large spending to comply with air emissions rules. Increasing investments in transmission assets helps diversify the regulated rate base and potentially facilitates compliance with evolving environmental standards by bringing in power from other regions. AEP does own and operate the 2,200 MW Cook nuclear plant in Michigan, that overall, increased the company's operational risk.

Financial Risk: Significant

Under our base-case scenario, we anticipate AEP's adjusted FFO to debt will be in the 15%-16% range over the next few years as the company benefits from recovery mechanisms like the investment cost rider, formulaic transmission rates, and forward test years for rate cases. Various rate mechanisms allow for timely recovery of costs and support more stable operating cash flow. We expect the company will continue to fund its investments in a manner that preserves credit quality.

Over the next several years, AEP will have elevated capital spending that will average about $7 billion per year. About 15% will be allocated to renewables generation, and about 70% will focus on wires-based operations. These benefit from a constructive regulatory framework that provides for timely investment recovery. This aggressive capital spending along with robust dividends results in discretionary cash flow that is highly negative, indicating external funding needs that we expect will include debt issuances. We expect adjusted debt to EBITDA to average 5.0x through 2021. We assess AEP's financial risk profile using our medial volatility financial benchmarks that reflect lower-risk regulated utility operations and effective management of regulatory risk. These benchmarks are more relaxed than those used for a typical corporate issuer.

Financial summary

Table 2

American Electric Power Co. Inc.--Financial Summary

Industry Sector: Electric					
	--Fiscal year ended Dec. 31--				
	2019	2018	2017	2016	2015
(Mil. $)					
Revenue	15,440.0	15,848.0	15,080.3	15,988.9	16,033.4
EBITDA	5,712.4	5,252.2	5,538.7	5,493.8	5,420.2
Funds from operations (FFO)	4,601.9	4,210.1	4,612.1	4,555.6	4,367.2
Interest expense	1,292.9	1,241.6	1,088.0	1,060.7	1,082.7
Cash interest paid	1,104.4	1,066.8	927.8	908.8	932.8
Cash flow from operations	4,387.9	5,047.3	4,098.4	4,309.0	4,519.4
Capital expenditure	6,078.0	6,321.0	5,750.7	4,857.9	4,538.7
Free operating cash flow (FOCF)	(1,690.1)	(1,273.7)	(1,652.3)	(548.9)	(19.3)
Discretionary cash flow (DCF)	(3,060.6)	(2,529.2)	(2,844.2)	(1,669.9)	(1,078.3)
Cash and short-term investments	449.5	393.2	376.3	330.5	292.2
Gross available cash	449.5	393.2	376.3	542.2	563.2
Debt	29,754.0	26,216.3	23,278.4	22,002.8	20,314.8
Equity	20,783.9	19,128.8	18,313.6	17,420.1	17,904.9

Table 2

American Electric Power Co. Inc.--Financial Summary (cont.)

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2019	**2018**	**2017**	**2016**	**2015**
Adjusted ratios					
EBITDA margin (%)	37.0	33.1	36.7	34.4	33.8
Return on capital (%)	6.5	7.2	9.1	9.6	9.5
EBITDA interest coverage (x)	4.4	4.2	5.1	5.2	5.0
FFO cash interest coverage (x)	5.2	4.9	6.0	6.0	5.7
Debt/EBITDA (x)	5.2	5.0	4.2	4.0	3.7
FFO/debt (%)	15.5	16.1	19.8	20.7	21.5
Cash flow from operations/debt (%)	14.7	19.3	17.6	19.6	22.2
FOCF/debt (%)	(5.7)	(4.9)	(7.1)	(2.5)	(0.1)
DCF/debt (%)	(10.3)	(9.6)	(12.2)	(7.6)	(5.3)

Source: S&P Global Ratings.

Reconciliation

Table 3

American Electric Power Co. Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--Rolling 12 months ended Sept. 30, 2020--									
American Electric Power Co. Inc. reported amounts (mil. $)										
	Debt	**Shareholders' equity**	**Revenue**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Dividends**	**Capital expenditure**
	32,464.1	20,365.9	14,923.9	5,505.8	2,712.2	1,168.3	6,123.7	3,842.4	1,408.1	6,474.6
S&P Global Ratings' adjustments										
Cash taxes paid	--	--	--	--	--	--	40.6	--	--	--
Cash interest paid	--	--	--	--	--	--	(1,023.3)	--	--	--
Reported lease liabilities	1,233.8	--	--	--	--	--	--	--	--	--
Operating leases	--	--	--	286.0	34.6	34.6	(34.6)	251.4	--	--
Equity-like hybrids	(1,655.0)	1,655.0	--	--	--	(28.8)	28.8	28.8	28.8	--
Accessible cash and liquid investments	(618.7)	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	100.0	(100.0)	(100.0)	--	(100.0)
Share-based compensation expense	--	--	--	61.4	--	--	--	--	--	--
Securitized stranded costs	(1,028.8)	--	48.1	48.1	(27.5)	(27.5)	27.5	75.7	--	--
Power purchase agreements	336.0	--	--	35.1	12.1	12.1	(12.1)	23.0	--	23.0

Table 3

American Electric Power Co. Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts (cont.)

Asset-retirement obligations	544.2	--	--	102.5	102.5	102.5	--	--	--	--
Nonoperating income (expense)	--	--	--	--	265.9	--	--	--	--	--
Noncontrolling interest/minority interest	--	268.7	--	--	--	--	--	--	--	--
Debt: Other	536.5	--	--	--	--	--	--	--	--	--
EBITDA: Other income/(expense)	--	--	--	84.7	84.7	--	--	--	--	--
Depreciation and amortization: Impairment charges/(reversals)	--	--	--	--	156.4	--	--	--	--	--
Depreciation and amortization: Other	--	--	--	--	(84.7)	--	--	--	--	--
Interest expense: Other	--	--	--	--	--	33.1	--	--	--	--
Total adjustments	(652.1)	1,923.7	48.1	617.9	544.0	226.0	(1,073.1)	278.8	28.8	(77.0)

S&P Global Ratings' adjusted amounts

	Debt	Equity	Revenue	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Dividends	Capital expenditure
	31,812.0	22,289.6	14,972.0	6,123.7	3,256.2	1,394.3	5,050.5	4,121.2	1,436.9	6,397.6

Source: S&P Global Ratings.

Liquidity: Adequate

We assess AEP's liquidity as adequate because we believe its sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. The assessment also reflects the company's general prudent risk management, sound relationships with banks, and a generally satisfactory standing in credit markets.

Principal liquidity sources

- Cash and liquid investments of about $350 million;
- Estimated cash FFO of about $5 billion; and
- Credit facility availability of about $4 billion.

Principal liquidity uses

- Capital spending of $2.5 billion;
- Debt maturities, including outstanding commercial paper, of about $2.1 billion; and
- Dividends of about $1.4 billion.

Debt maturities

- 2021: $2 billion
- 2022: $3 billion
- 2023: $740 million
- 2024: $706 million
- Thereafter: $18.9 billion

Covenant Analysis

As of June 30, 2020, AEP had adequate cushion as per the financial covenant of consolidated total debt to total capital of no more than 67.5%.

Compliance expectations

- The company was in compliance as of June 30, 2020.
- Single-digit-percentage EBITDA growth and elevated capital spending should still permit a cushion.
- Although we believe the company will remain in compliance, covenant headroom could decrease without adequate cost recovery of capital investments or if, while making these investments, debt rises rapidly without adequate growth in equity.

Requirements

- Current: no more than 67.5%
- As of year-end 2021: 67.5%
- As of year-end 2022: 67.5%

Environmental, Social, And Governance

We consider environmental factors in our rating analysis. AEP's social and governance factors are generally comparable with those of its peers. AEP through vertically integrated electric utilities and non-utility generation, owns generation capacity of about 24,000 MW, of which 72% is based on fossil fuels (about 43% coal; 29% natural gas). Because of the sizable generation capacity and exposure to fossil fuels, AEP's environmental risks are greater than those of some vertically integrated peers. The company's reliance on coal-fired generation exposes it to heightened risks, including the ongoing cost of operating older units in the face of disruptive technology advances and the potential for increasing environmental regulations that require significant capital investments. AEP began reducing its reliance on coal through plant retirements and investments in wind and solar generation, and batteries. Exposure to nuclear generation (8% of the generation fleet) introduces higher operational risks and plant retirement responsibilities. AEP's management is taking active steps to reduce its fleet's environmental footprint, committing to an 80% reduction of carbon dioxide emissions by 2050 from 2000 levels.

From a social perspective, AEP's internal safety and health management systems processes enable it to effectively serve one of the largest service territory footprints in North America. AEP's cost-reduction efforts enabled the company to stabilize operations and maintenance costs in an inflationary economic environment, facilitating competitive customer rates. This is important because all distribution and transmission companies are moving proactively to deploy capital to upgrade, modernize, and harden assets in the wake of recent weather events and for technological reasons. AEP's governance practices are consistent with other publicly traded utilities.

Group Influence

Under the group rating methodology, we assess AEP as the parent of the group that includes all the operating subsidiaries. AEP's group credit profile is 'a-', leading to an issuer credit rating of 'A-'.

Issue Ratings - Subordination Risk Analysis

- The short-term rating is 'A-2', based on our issuer credit rating.
- We rate AEP's mandatory convertible equity units two notches below the issuer credit rating. This reflects that the units consist of a remarketable junior subordinate note and a purchase contract that obligates the owners of the units to purchase AEP's common stock in three years.

Capital structure

AEP's capital structure consists of about $28 billion of debt, of which $22 billion is priority debt.

Analytical conclusions

We rate AEP's unsecured debt one notch below the issuer credit rating because priority debt exceeds 50% of the company's consolidated debt, after which point AEP's debt is considered structurally subordinated.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013

- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of January 13, 2021)*

American Electric Power Co. Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB
Senior Unsecured	BBB+
Issuer Credit Ratings History	
02-Feb-2017	A-/Stable/A-2
16-Sep-2016	BBB+/Watch Pos/A-2
29-Sep-2014	BBB/Positive/A-2

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Caleb R. Loveman

Caleb R. Loveman
Utility Analyst
Indiana Office of Utility Consumer Counsel
Cause No. 45600 CenterPoint

October 28, 2021

CERTIFICATE OF SERVICE

This is to certify that a copy of the ***OUCC's Testimony of Caleb R. Loveman*** has been served upon the following parties of record in the captioned proceeding by electronic service on October 28, 2021.

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