CME Compendium

Panel 5Ai

OPG 2017-2021 Rates – EB-2016-0152

Board Staff Interrogatory #13

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Ref: Exh C1-1-1 Attachment 1, page 18
OPG is transitioning to an incentive rate plan for hydroelectric generation.

Please provide any analysis performed or relied upon by Concentric in evaluating changes in regulatory risk exposure to OPG's hydroelectric facilities as a result of transitioning to the five-year incentive rate plan. If an analysis was conducted, please include associated workpapers.

Response

The following response was provided by Concentric Energy Advisors:

Concentric conducted a qualitative assessment of the change in risk associated with the transition to a five-year incentive rate plan for OPG's hydroelectric facilities. There are no associated work papers; this assessment, however, considered the following factors:

1. *Identification of the change in risk from the prior regulatory framework adopted by the OEB for OPG's prescribed hydroelectric facilities to that proposed for the 2017-2021 plan period.*

   Under the prior regulatory framework, OPG submitted cost-of-service projections covering a two year test period (e.g., January 1, 2014 through December 31, 2015 in EB-2013-0321). That practice was also followed in OPG's prior two rate applications (EB-2007-0905 and EB-2010-0008). As described by the Board, the ratemaking approach was straightforward:

   At the highest level, OPG's payment amounts result from a simple equation: OPG's reasonably incurred costs divided by the number of megawatt-hours it is expected to produce (i.e. the production forecast).[1]

   Under the proposed rate plan, a key element will be the deliberate decoupling of the payment amounts OPG receives from the costs of its hydroelectric facilities for a five year period. This will be accomplished through a comprehensive I-X price cap (including

[1] EB-2013-0321, at 8.

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of Capital

capital and O&M) for the payment amount. That entails a transfer of risk from customers to OPG for the following reasons:

- Under I-X, the likelihood that actual costs will differ from revenues is increased as compared to a cost of service rate setting framework.
- The rate plan extends to five years from two, increasing the probability that costs and rates will diverge. Even if one considers the historical tendency for OPG to hold rates fixed for a third year following its two-year rate periods, the option to file for the rate increase existed, and it will not in the proposed plan (unless the 300 basis point off-ramp is reached).
- The "going-in" rates are those adopted in EB-2013-0321 (adjusted for tax losses as discussed in Ex. A1-3-2 section 2.3.2), creating in essence an eight year rate plan, with the first two years based on projected cost of service, one fixed, and the remaining five under the I-X price cap.

2. *Credit rating agency assessments of the risks associated with performance based regulatory frameworks.*

Credit rating agencies have identified performance based regulation mechanisms as riskier than cost of service-based rates. As cited in Concentric's evidence (Exhibit C1-1-1 Attachment 1 at 25), DBRS ranks the regulatory risk of cost of service as "Excellent", but ranks incentive regulation programs of 4-5 years as "Satisfactory," two notches lower on its scale. Further, in its April 2016 ratings report on OPG, DBRS stated, "DBRS believes that profitability for OPG could continue to be challenged following a switch to an IR framework, as the introduction of productivity and efficiency targets could further depress earnings."[2]

In its assessment of the U.S. regulatory environment, Standard and Poors adopts a similar view of the impacts of incentive regulation on credit quality:

> *We typically view jurisdictions as credit-supportive if regulators use symmetrical incentive mechanisms sparingly in the rate-setting process. When incentives play a larger role in the rate-setting approach, but are well-designed to evenly allocate risk, we see less support for credit quality. We regard still lower jurisdictions where incentives dominate and are poorly designed. Jurisdictions where incentives significantly degrade risk and are part of a comprehensive incentive regime harbor the most risk for creditors.*[3]

These factors, collectively, led to the assessment of increased risk associated with the change to an incentive rate mechanism for the hydroelectric facilities.

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[2] Ex. A2-3-1, Attachment 1, at 1.
[3] Assessing U.S. Investor-Owned Utility Regulatory Environments, Standard and Poor's, August 10, 2016, at 6.

Board Staff Interrogatory #17

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Ref: Exh C1-1-1/Attachment 1, page 25 of 73
In its evidence, Concentric makes reference in footnote 46 to a methodology paper by Dominion Bond Rating Service (DBRS) as the source for its summary in Table 3.

a) Please file the DBRS study entitled: "Methodology: Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry," October 19, 2015.

b) Are there any other studies or reports conducted or commissioned by credit rating agencies regarding the criteria on the form of economic regulation that credit rating agencies use for assessing the credit rating of regulated firms that Concentric is aware of and used in its report? If so, please provide copies of all such reports.

c) If such reports in b) were used, please indicate how and where they were used by Concentric in its analysis. If they were not used, please indicate why not.

Response

The following response was provided by Concentric Energy Advisors:

a) Please see Attachment 1.

b) In its April 2016 ratings report on OPG, DBRS stated, "DBRS believes that profitability for OPG could continue to be challenged following a switch to an IR framework, as the introduction of productivity and efficiency targets could further depress earnings."[1] Please see Attachment 2.

At the time Concentric filed its report, Concentric was not aware of any other reports from credit rating agencies regarding how the form of economic regulation (*i.e.*, cost of service vs. incentive regulation) affects credit risk. In August 2016, however, S&P published a report expanding on the factors that it considers in assessing the regulatory environments of U.S. investor-owned utilities (please see Attachment 3). In that report, S&P provides its views regarding how incentive regulation affects credit quality. The S&P report is generally consistent with the DBRS report, and provides additional evidence that rating

[1] DBRS Rating Report, "Ontario Power Generation Inc.," April 25, 2016, at 1.

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of Capital

agencies tend to view incentive regulation as potentially negative for credit quality, depending on how the incentive regulation regime is designed and the duration of the IR plan.

> *If a jurisdiction uses incentives as the primary ratemaking tool and institutes a comprehensive incentive program that allows revenues and costs to diverge, we evaluate the incentive mechanisms' effect on a utility's earnings capability and stability. A common approach features an extended period between rate case reviews, during which rates change according to a formula based on inflation, a predetermined productivity factor, and capital spending. An incentive-based program can be close to credit neutral compared with systems that permit more frequent and dynamic rate changes if the risk is symmetrical (i.e., an equal opportunity to earn over of under the authorized return and equivalent reward or penalty for doing so) and limited (a maximum or minimum earnings band). The effect on regulatory risk depends on whether we believe the efficiency targets are realistic and achievable, the regulator's treatment of disparities in actual versus authorized spending, and the framework's flexibility to adjust returns for capital market conditions. If there are operating standards, we determine whether they fairly reward or punish utilities if performance deviates from expectations.*
>
> *There is a muted effect on regulatory risk in jurisdictions where incentives are not central, but are instead used only to augment cost-of-service regulation. A moderate amount of incentives that carry symmetrical risks can even modestly support better credit quality. For example, a fuel adjustment and purchased-power clause with a sharing mechanism that affects less than 10% of the total fuel costs and cuts both ways when commodity markets change can modestly reduce risk by offering the utility a mild incentive for effective procurement and efficient operations, without unduly exposing it to commodity price risk.*[2]

S&P concludes:

> *We typically view jurisdictions as credit supportive if regulators use symmetrical incentive mechanisms sparingly in the rate-setting process. When incentives play a larger role in the rate-setting approach, but are well-designed to evenly allocate risk, we see less support for credit quality. We regard still lower jurisdictions where incentives dominate and are poorly designed. Jurisdictions where incentives significantly degrade risk and are part of a comprehensive incentive regime harbor the most risk for creditors.*[3]

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2 S&P Global Ratings, Assessing U.S. Investor-Owned Utility Regulatory Environments, August 10, 2016, at 5.

3 Ibid, at 6.

c) The April 2016 DBRS report discussed in part (b) was reviewed as part of Concentric's analysis and considered in terms of how the ratings agencies view OPG from a business and financial risk perspective. The report was specifically cited in Exhibit C1-1-1 Attachment 1, page 17.

As discussed in the response to part (b), the S&P report was unavailable at the time Concentric filed its report. The S&P report was published in August, 2016 and provides additional insight into how credit rating agencies view the effect of incentive regulation on credit risk. The S&P report is generally consistent with the DBRS report, and provides additional evidence that rating agencies tend to view incentive regulation as potentially negative for credit quality, depending on how the incentive regulation regime is designed and the duration of the IR plan.

S&P Global
Ratings

Research

Assessing U.S. Investor-Owned Utility Regulatory Environments

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Table Of Contents

Assessing U.S. Investor-Owned Utility Regulatory Environments

Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile. One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions where a utility operates. A utility management team's skill in dealing with regulatory risk can sometimes overcome a difficult regulatory environment. Conversely, companies' regulatory risk can increase even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. We modify our assessment of regulatory advantage to account for this dynamic in our ratings methodology (for the criteria we use to rate utilities, see "Corporate Methodology," and "Key Credit Factors For The Regulated Utilities Industry," published Nov. 19, 2013, on RatingsDirect.)

There are specific factors we use in the U.S. to assess the credit implications of the numerous regulatory jurisdictions here that help us determine the "preliminary regulatory advantage" in our credit analysis of each investor-owned regulated utility. We organize the subfactors of regulatory advantage into four categories:

- Regulatory stability,
- Tariff-setting procedures and design,
- Financial stability, and
- Regulatory independence and insulation.

Regulatory Stability

The foundation of our opinion of a jurisdiction is the stability of its approach to regulating utilities, encompassing transparency, predictability, and consistency. Given the maturity of the U.S. investor-owned utility industry, the long history of utility regulation (going back to the early 20th century) and the well-established constitutional protections accorded to utility investments, we emphasize the principle of consistency when weighing regulatory stability. We also incorporate the degree to which the regulatory framework either explicitly or implicitly considers credit quality in its design.

7

Regulatory Change Can Bring Stability, Or Take It Away

While stability is one of the four pillars of our approach to evaluating regulatory risk, experience shows us that it's not an absolute positive or negative for creditors. Change can boost or lessen risk, and any improvement in a regulatory regime will overcome any negative connotations of instability. A good example is Michigan, which in about 2008 revamped its whole approach to utility regulation. As implemented in subsequent years by the Michigan Public Service Commission, the reforms have almost completely transformed the regulatory environment in that state.

However, during any period of change, we see the uncertainties surrounding the process and the outcome as possible major causes of risk. A more recent and still ongoing example is New York, where the Public Service Commission's (NYPSC) Reforming the Energy Vision (REV) proceeding is possibly revving up risk for utilities. While the NYPSC seemed at first to be focusing more on high-minded policy questions than on making a lot of changes to day-to-day operations, the current phase could eventually disrupt the way utilities make money and affect their ability to earn the authorized return. If the end result is greater operating risk with no opportunity to earn greater returns, our assessment of the regulatory environment could change.

Durability of regulatory system

An established, dependable approach to regulating utilities is a hallmark of a credit-supportive jurisdiction. Creditors lend capital to utilities over long periods to fund the development of long-lived assets. A firm understanding of the basic "rules" that will govern how the utility will recover its costs, including servicing its debt and the return on its capital over an extended period, is essential to accurately assess credit risk. Major or frequent changes to the regulatory model invariably raise risk due to the possibility of future changes. Steady application of transparent, comprehensible policies and practices lowers risk.

How long a regulatory framework has been in place is the most important factor in this area. We view jurisdictions as most supportive when there have been no major changes or where the approach has been consistent for a long time and is not prone to further changes. Jurisdictions that have undergone a major, fundamental change in the regulatory paradigm that seems to be working well are a little less supportive, and less so a jurisdiction that is transitioning to a new regulatory approach. Credit risk rises if the transition attracts political attention. The less-supportive jurisdictions are those that frequently alter the basic regulatory approach. We also view the framework's development less favorably if policy disputes or legal actions cause contention, indicating that the political consensus regarding utility regulation is fragile.

Some jurisdictions permit competitive markets to prevail for some important functions of the delivery of utility services, notably wholesale markets for electricity and retail markets for electric or gas service. In others, vertical integration is the norm. A jurisdiction's credit-supportiveness is more prone to suffer if market forces directly influence major cost items that utilities could otherwise control through cost-based regulation because of the potential volatility it creates. The risk inherent in a market-based model is straightforward: utility rates are more volatile when markets influence them rather than fully embedded costs, and regulators are apt to resist full and timely recovery when market price changes are abrupt and substantial (and perhaps misunderstood). We observe less support for credit quality in jurisdictions that are in the midst of deregulating important parts of the utility framework. The uncertainty of the timing

8

of reaching the outcome--and what the result will be--is a negative factor from a credit perspective. Utilities are also prone to financial stress when the transition to competition causes potential "rate shock" for customers that regulators could resist.

Transparency of regulatory framework and attitude toward credit quality

We believe regulation works best when it is rule-based. Creditor interests are better protected by the presence of and adherence to a pre-set code of rules and procedures that we can look to when assessing risk. Risk is lower when the rules are more transparent and when they take into account a utility's financial integrity. We regard jurisdictions that require regulators to protect utilities' financial soundness and have transparent policies and procedures as the most credit-supportive. We ascribe higher risk in jurisdictions where policies and procedures support financial integrity, but where inconsistency can selectively arise. We believe a jurisdiction provides even less support when transparency merely exists. We see less support when any of these credit factors are absent, or if the regulator's record on following precedent is poor.

Tariff-Setting Procedures

We review rate decisions as part of our surveillance on each U.S. utility. We focus on the jurisdiction's overall approach to setting rates and the process it uses to establish base rates (practices pertaining to separate tariff provisions for large expenses are in the "Financial Stability" part of our analysis). We focus on whether base rates, over time, fairly reflect a utility's cost structure and allow a fair opportunity to earn a compensatory return that provides creditors with a financial cushion that supports credit quality. If the process is geared toward an incentive-based system, our analysis centers on the risks related to the incentive mechanisms. If the jurisdiction has vertically integrated utilities, we review the resource procurement process and assess how it affects regulatory risk.

Rate Cases Can Affect Creditworthiness

Although not common, rate case outcomes can sometimes lead directly to a change in our opinion of creditworthiness. Often it's a case that takes on greater importance because of the issues being litigated. For example, in 2010, we downgraded Florida Power & Light and its affiliates following a Florida Public Service Commission rate ruling that attracted attention due to drastic changes to settled practices on rate case particulars like depreciation rates. More recently, in June 2016, we downgraded Central Hudson Electric & Gas due to our revised opinion of regulatory risk. While that reflected the company's own management of regulatory risk, it was prompted in part by other rate case decisions in New York that highlighted the overall risk in the state.

Sometimes change comes from outside the usual rate case process. The aforementioned improvement in Michigan (see the previous sidebar) came from legislative changes that reformed rate case procedures such as interim rate increases and time limits on rate decisions. In March 2016, we affirmed our ratings on Entergy Corp. and kept the outlook positive based on the prospect of lower regulatory risk as the company pursues strategic changes in its various jurisdictions. For instance, legislation in Arkansas allowing for formula rates could better enable Entergy to manage regulatory lag and earn its authorized return.

9

Ability to timely recover costs

We review authorized returns and capital structures in our analysis, but we focus mainly on actual earned returns. Examples abound of utilities with healthy authorized returns that have no meaningful expectation of earning those returns due to, for example, rate case lag (i.e., the relationship between approved rates and the age of the costs used to set those rates) or expense disallowances. Also, the stability of the returns is as important as the absolute level of financial returns, and we note the equity component in the capital structure used to generate the revenue requirement in rate proceedings. Higher authorized and earned returns and thicker equity ratios translate into better credit measures and a more comfortable equity cushion for creditors. We consider a regulatory approach that allows utilities the opportunity to consistently earn a reasonable return as a positive credit factor.

A very credit-supportive jurisdiction is one in which all of the utilities it regulates consistently earn above-average returns. We assess jurisdictions lower if only some of them do, and lower still if the earnings records are below average or highly variable from year to year. We deem jurisdictions as weaker when all utilities earn well-below-average returns, and we consider jurisdictions where all utilities consistently earn exceedingly poor returns, including years with negative returns, as weakest.

We consider "regulatory lag" along with the record of earned returns to assess timeliness. Credit-supportive jurisdiction typically have a track record of little regulatory lag, indicating that responsibility for a poor or uneven earnings history lies more with management than its regulators. In addition to the regulator's efficiency in completing rate cases, we consider the obsolescence of the costs on which the rates are based, the timing of interim rates, and other practices (such as allowing rates to automatically change in a future period based on inflation) that affect a utility's ability to earn its authorized return.

If a jurisdiction uses incentives as the primary ratemaking tool and institutes a comprehensive incentive program that allows revenues and costs to diverge, we evaluate the incentive mechanisms' effect on a utility's earnings capability and stability. A common approach features an extended period between base rate reviews, during which rates change according to a formula based on inflation, a predetermined productivity factor, and capital spending. An incentive-based program can be close to credit-neutral compared with systems that permit more frequent and dynamic rate changes if the risk is symmetrical (i.e., an equal opportunity to earn over or under the authorized return and equivalent reward or penalty for doing so) and limited (a maximum or minimum earnings band). The effect on regulatory risk depends on whether we believe the efficiency targets are realistic and achievable, the regulator's treatment of disparities in actual versus authorized spending, and the framework's flexibility to adjust returns for capital market conditions. If there are operating standards, we determine whether they fairly reward or punish utilities if performance deviates from expectations.

There is a muted effect on regulatory risk in jurisdictions where incentives are not central, but are instead used only to augment cost-of-service regulation. A moderate amount of incentives that carry symmetrical risks can even modestly support better credit quality. For example, a fuel-adjustment and purchased-power clause with a sharing mechanism that affects less than 10% of the total fuel costs and cuts both ways when commodity markets change can modestly reduce risk by offering the utility a mild incentive for effective procurement and efficient operations, without unduly exposing it to commodity price risk.

10

We typically view jurisdictions as credit-supportive if regulators use symmetrical incentive mechanisms sparingly in the rate-setting process. When incentives play a larger role in the rate-setting approach, but are well-designed to evenly allocate risk, we see less support for credit quality. We regard still lower jurisdictions where incentives dominate and are poorly designed. Jurisdictions where incentives significantly degrade risk and are part of a comprehensive incentive regime harbor the most risk for creditors.

Financial Stability

When we evaluate U.S utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to creditors.

Creative Ratemaking Can Help...If Used Correctly

The ability of financial stability factors to help a utility maintain and smooth its cash flow gives prominence to this area of our analysis. In addition to the near-ubiquitous fuel clauses, we see utilities give more attention to obtaining so-called "disc" mechanisms (DSIC, for distribution system investment charge, is a common acronym for this kind of rate adjustment) that accelerate and stabilize cash flow realization when a utility pursues a strategy of boosting rate base to fuel earnings growth.

For instance, Duquesne Light recently filed for a DSIC mechanism in Pennsylvania in conjunction with a long-term plan to improve its distribution system. Approval, requested for October, would enhance our view of Duquesne's ability to manage regulatory risk, because it would consequently be joining the other Pennsylvania utilities that already benefit from this mechanism. On the other end of the spectrum, Mississippi Power's ongoing travails in obtaining rate relief for its Kemper coal-fired plant, which has experienced significant cost and schedule problems, points to how regulatory risk can deteriorate under stress when well-established procedures for handling large and risky capital projects are absent or not followed.

Treatment of significant expenses

When utilities have major expenses such as fuel and purchased power/gas/water, the presence of separate tariff provisions to facilitate full and contemporaneous recovery is the most prominent factor in this part of our analysis. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of management's control is a key feature of a credit-supportive regulatory jurisdiction. The analysis centers on the special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect our analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part when we assess regulatory advantage.

We consider jurisdictions to be very credit-supportive if utilities can recover all high-expense items through an automatic tariff clause that is based on projected costs, adjusts frequently, and has no record of any significant disallowances. We see more risk if separate mechanisms exist, but lack some of the above features. We view jurisdictions that lack independent rate mechanisms for large expenses and have a record of significant disallowances

as weakest.

Treatment of capital spending

When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.

Very supportive jurisdictions offer a separate recovery mechanism for all capital spending, a mandated current cash return during construction, and a bonus return for some or all capital projects. We deem a jurisdiction weaker if there is a separate mechanism for only certain kinds of spending and the cash return and higher return are subject to the regulator's discretion. We view jurisdictions that don't allow separate recovery or a current return as being lower on the scale. We assess a jurisdiction as weaker still when it doesn't have independent rate mechanisms for capital projects, and we view it as most risky when full recovery occurs only after a utility's assets become operational.

Cash-smoothing mechanisms

We have a more positive view of jurisdictions that use innovative regulatory provisions that help to smooth cash flow from period to period. For a jurisdiction that focuses on incentives in its basic approach to ratemaking, through multiyear rate plans or a formula rate plan, we view the availability of "reopeners" (to adjust rates for unexpected events out of the utility's control) as key to this part of our analysis. The utility's ability to petition for a rate increase when unexpected or uncontrollable costs arise in the midst of a long-term rate plan is a critical risk mitigant.

Other examples of risk-dampening regulatory policies include hedging program approvals, and decoupling (the separation of a utility's profits from sales) or weather-related mechanisms. If a utility seeks approval of a hedging program to manage exposure to commodity prices, it can reduce risk if there's a clearly stated hedging policy that its regulator has endorsed, and a track record of activity that conforms to the policy that has not been subject to regulatory second-guessing. A well-designed decoupling or weather-normalization mechanism that efficiently adjusts rates to offset the sales effect of economic conditions, customer usage trends, or weather will soften earnings and cash flow volatility to the benefit of creditors. If applicable, we view a record of regulatory responsiveness to extreme events for utilities that are prone to violent or disruptive weather (like hurricanes) as favorable for credit quality.

A jurisdiction is more credit-supportive if it makes extensive use of extraordinary and credit-supportive rate mechanisms. Also favorable are jurisdictions that use innovative mechanisms selectively, or have regulators that are receptive to reopeners where incentives are the main ratemaking method.

12

Regulatory Independence And Insulation

The role of politics in U.S. utility regulation is often misunderstood. In most jurisdictions, the regulator's function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service, but for other constituents as well. Creditors should recognize that utility regulation harbors political as well as economic risks. Therefore, how politics could influence regulation helps us evaluate a regulatory environment.

Political Influence On Utility Regulation Can Yield Unexpected Results

This is often the most variable area of our analysis and the most difficult to assess. The most dramatic, fairly recent reminder of how political forces can influence regulatory risk was last year's unexpected reversal by the popularly elected Mississippi Supreme Court of a significant rate increase granted for Mississippi Power to help pay for a major power plant under construction. Regulators, who were ordered to roll back rates and issue refunds, struggled to make decisions amid the strained political atmosphere and extra scrutiny that the Court's action had created. The episode also highlighted the greater regulatory risk that attends jurisdictions that expose regulators (and in this case the appellate court) to direct political accountability.

Another more recent example of political influence on regulation underscores the complexity of this area of analysis, because it featured many participants at both the federal and state level. Electric utilities in Ohio had a credible strategy for dealing with rising competitive risks in their merchant generation portfolios by offering the output to retail customers at pre-set prices on a long-term basis, which the state regulator approved. The federal regulator (Federal Energy Regulatory Commission, or FERC), responding to complaints by other generators that the plan would inhibit the operation of the competitive electricity market, essentially overruled the Ohio regulators and blocked the utilities from pursing the strategy that would have reduced its risk profile. It essentially decided that its political interest in and ideological commitment to efficient electricity markets overrode the state's political interest in stable electric rates. The saga is still continuing with attempts to bypass the FERC's ruling through other means, but no matter what the ultimate result, we see how political considerations can increase risk.

Political independence of regulator

The primary factor in this part of our analysis is the regulators' (and, when relevant, the judicial body that reviews the regulators' decisions) political independence. We think it's more credit-supportive when the regulator is substantially independent of the political process. Jurisdictions are somewhat less favorable when insulation is strong, such as when the executive branch of government appoints regulators subject to legislative approval. We consider jurisdictions to be further down the scale when the same voters who pay utility bills directly elect the regulators, but institutional efforts have been made to erect some shield for regulators from transient political concerns. We view jurisdictions that arrange for direct political accountability of regulators that persistently influences regulatory decisions as less supportive.

Record of direct political intervention

The overall atmosphere that a regulator operates in can affect its ability to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utilities in managing business and financial risk. In this part of our

13

evaluation, we may consider the tone that politicians set, the history of political insulation given to the regulatory body and the courts that review its actions, and the behavior of important constituencies that intervene in utility proceedings. We also track the public visibility of utility issues, because we believe that the likelihood of constructive regulatory behavior increases with the comparative obscurity of utility issues.

We view a jurisdiction as having a lower risk if the regulatory environment is marked by cooperative attitudes and constructive interventions in important matters before the regulator. We assess a jurisdiction lower when the atmosphere is more combative and restricts the regulator's ability to act in the long-term best interests of all parties. We consider jurisdictions as weaker if the regulatory environment is so infused with short-term political influence over regulatory decisions that the regulator can't effectively consider investor interests in its decisions.

Related Criteria And Research

Related Criteria

- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

Only a rating committee may determine a rating action and this report does not constitute a rating action.

14

Board Staff Interrogatory #21

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Ref: Exh C1-1-1 Attachment 1, pages 18-26

Pages 18-23 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments in which it concludes that OPG's operational, regulatory and political risk with respect to the nuclear generation assets increases, while acknowledging that there are some mitigating factors with respect to OPG's approach to project planning and management of the DRP and the provisions of O.Reg. 53/05 effective January 1, 2016.

Pages 24-26 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments of OPG's rate proposals. In particular, on the middle of page 26, Concentric describes the nuclear rate smoothing proposal and how the variance between revenues and revenue requirement will be tracked in the rate smoothing deferral account per O.Reg. 53/05.

Nonetheless, Concentric concludes on page 26:

> Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

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[2]Further, for hydroelectric, any difference in the revenue requirement between the current 45% equity thickness and that determined by the OEB in its decision to this application, and which OPG has proposed to be 49%, would be tracked for later disposition.
[3] Currently *Report of the Board on the Cost of Capital for Ontario's Rate-regulated Utilities, (EB-2009-0084)*, December 11, 2009.

The discussions on pages 18-23 and on page 26 are fully qualitative in nature. With respect to the nuclear rate setting proposal, please indicate how Concentric has translated the qualitative points on these pages to conclude that, as a result, OPG is exposed to "material incremental risk" over the 2017-2021 plan period.

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of Capital

Response

The following response has been prepared by Concentric Energy Advisors:

In regard to the pages of Concentric's report referenced in the interrogatory, and as further discussed in Concentric's report, there are generally five major risk areas related to regulated utility nuclear power generation, including: (1) the ability to implement large and complex projects on time and on budget; (2) increases in costs and/or outage durations related to emerging safety regulations (*e.g.*, Fukushima-response costs); (3) age-related degradation of station components, discovery of unexpected conditions and/or extended outage durations that put nuclear plants at further risk of producing lower-than-forecasted power; (4) decommissioning of retired nuclear plants and long-term management of used nuclear fuel and other nuclear waste, including the cost and timing of decommissioning work and the ability to fund that work; and (5) the ability to recover costs, including a return, in a timely manner.

Concentric evaluated OPG's risk factors in key risk areas, as described further in Exhibit C1-1-1/Attachment 1, at pages 18 to 23. Based on that evaluation, Concentric concluded that:

- The Darlington Refurbishment Project presents an incremental source of risk to the Company that will become increasingly significant during the upcoming rate-setting period. Specifically, as discussed in Concentric's report, the DRP is a significant undertaking, as the $12.8 billion cost of the project represents over 100% of OPG's total regulated rate base as of EB-2013-0321 (i.e., the rate base most recently approved by the Board), and approximately 70% of OPG's overall net in-service property, plant and equipment ("PP&E") balance (both prescribed and non-regulated). Relative to the size of the Company, the DRP is one of the most significant undertakings in the North American nuclear industry in the recent past. As further demonstrated in Concentric's report, the DRP is considerably larger, relative to OPG's size, than two other nuclear megaprojects that are currently ongoing in North America;

- OPG's plans to pursue extended Pickering operations beyond 2020 also poses considerable risks;

- OPG also faces risks due to degradation of Darlington's primary heat transport pump motors;

- OPG continues to face risks related to the implementation of new safety and regulatory requirements;

- OPG's forecasts for nuclear costs and generation levels are being made in the face of this uncertainty, while also covering a longer, five-year term.

With regard to the nuclear smoothing proposal specifically, Concentric noted in its report that the proposal involves the deferred recovery of a substantial portion of the OEB-approved revenue requirement until after the end of the Darlington Refurbishment Project. As shown

in Exhibit A1-3-3 Page 2, under OPG's rate smoothing proposal the Company will defer $1.6 billion, or nearly 10% of the nuclear revenue requirement, through 2021. That will decrease cash flow relative to what it would be absent smoothing. This deferral of revenue and reduced cash flow will occur during a period in which OPG forecasts issuing $4 billion in debt, and the maintenance of credit support is critical (*see*, Exhibit A1-3-3 page 4). Incremental increase in financial risk arises, in part, due to inherent uncertainty related to the collection of amounts deferred for a decade into the future (*see*, Exhibit C-1-1/Attachment 1, at 28).

From a business risk perspective, the risks discussed in the Concentric report and summarized above could manifest themselves in terms of variability in cash flows and earnings that impact the ability of OPG to recover its costs. That variability in cash flows and earnings could occur through either changes in cost levels or changes in generation levels (or both). In Concentric's opinion, the combination of the factors described in the Concentric report and summarized above could lead to significant variability in cash flows and earnings, and thus, in conjunction with the increasing proportion of nuclear power in OPG's generation mix, combine to create material incremental risk for the Company.

From an investor's perspective, the business risk assessment process is inherently qualitative in nature and involves the application of reasoned judgment on the part of the analyst. In fact, the business risk analyses performed by credit ratings agencies such as S&P, Moody's, and DBRS are largely qualitative in nature as well. For instance, the ratings agencies stress the importance of factors such as the quality, consistency and predictability of the regulatory regime in which a utility operates, and the types of businesses in which a utility engages (*e.g.*, transmission and distribution vs. generation). In addition, Concentric's comparative risk analysis, presented in Exhibit C1-1-1 Attachment 1, pages 30 through 41, is used in conjunction with Concentric's business risk assessment of OPG to provide context for where, within a reasonable range, OPG's equity ratio should be set by the Board. Based on the combination of those analyses, Concentric concluded that an equity ratio of no less than 49% was appropriate for OPG.