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June 3, 2016

Jeffrey Pursley
Executive Director
300 The Atrium
1200 "N" Street
Lincoln, NE 68509-4927

RE: Before the Nebraska Public Service Commission – Application No. NG-0086
In the Matter of Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, Omaha, seeking approval of its Cost of Service Gas Hedge Agreement with Black Hills Utility Holdings, Inc.

Dear Mr. Pursley:

I am transmitting herewith the original and eight copies of the "Post-Hearing Brief of the Public Advocate" in the above-captioned matter. I did not see any requirement in the rules that an electronic version be provided, but if one is needed, please let me know.

Sincerely,

William F. Austin
For the Firm
waustin@baylorevnen.com

WFA/ljd
Enclosures

cc: Doug Law, Esq.
Attorney for Black Hills

1387231

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the Matter of Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, Omaha, seeking Approval of its Cost of Service Gas Hedge Agreement with Black Hills Utility Holdings, Inc.	Application No. NG-0086 POST-HEARING BRIEF OF PUBLIC ADVOCATE

INTRODUCTION

On or about September 30th of 2015, Black Hills/Nebraska Gas Utility Company, LLC d/b/a Black Hills Energy (the "Company") filed an Application (E100:26, Vol III) seeking an order from the Nebraska Public Service Commission (the "PSC") authorizing the Company to enter into a proposed Cost of Service Gas Agreement (the "COSG Agreement") with Black Hills Utility Holdings, Inc. ("BHUH"). Essentially, the Company is seeking a prudency review of its proposed Cost of Service Gas Program pursuant to Neb. Rev. Stat. § 66-1854 (Reissue 2009). The Application requests other ancillary relief such as revising tariff sheets and authorizing the recovery of amounts incurred under the COSG Agreement from customers through the Purchased Gas Cost Adjustment (PGA) clause, approving the hedge participation level, and granting any necessary waivers from affiliate rules or ring-fencing commitments.

However, it is the question of prudency that is at the heart of this application. Neb. Rev. Stat. § 66-1854 (Reissue 2009) says, in pertinent part, that:

> "(1) The commission shall allow jurisdictional utilities to implement and thereafter modify gas supply cost adjustment rate schedules that reflect increases or decreases in the cost of the utility's gas supply such as (a) federally regulated wholesale rates for energy delivered through interstate facilities, (b) direct costs for natural gas delivered, or (c) costs for fuel used in the manufacture of gas. Such costs may, in the discretion of the commission, include costs related to gas price volatility risk management activities, the

costs of financial instruments purchased to hedge against gas price volatility, if prudent, and other relevant factors...."(Emphasis supplied.)

The Company is asking the PSC to prospectively find that entering into the COSG Agreement with BHUH is a reasonable and prudent step to take on behalf of the ratepayers.

In *KN Energy, Inc. v Cities of Alliance and Oshkosh*, 266 Neb. 882, 670 N.W. 2d 319 (2003), the Nebraska Supreme Court, in addressing whether the terms of the infamous P-0802 Contract were reasonable and prudent was required to formulate a test for determining the prudence of a utility's expenses. The Court adopted the Federal Energy Regulatory Commission test from New England Power Company, 31 FERC. Essentially, to determine the prudence of specific costs, the appropriate test to be used is whether they are costs that a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time.

As a New York Appellate Court pointed out in *National Fuel Gas Distribution Corp. v Public Service Commission*, 71 AD3d 62, 893 NY Supp. 2d 652 (2009):

> In determining whether a utility may recover certain costs [the Commission's] rate-setting powers necessarily include assessment of "the prudence of a utility's actions as those actions impact upon the ratepayers"...."Prudence . . . is determined by judging whether the utility acted reasonably, under the circumstances at the time, considering that the Company had to solve its problems prospectively rather than in reliance on hindsight".... Id. at 66, 893 NY Supp. 2d at 655.

It is a rather broad test; the PSC is here being asked to determine the reasonableness of these potential expenses in relation to the future effect they will have on ratepayers, as opposed to reviewing the expenses incurred in hindsight. It is important to keep in mind that, since this has been cast as a form of hedging, it is solely within the discretion of the PSC to approve it or not.

There are a number of other collateral issues that are in dispute in this proceeding, e.g., the actual amount of volatility that utilities and ratepayers may encounter in the future; the appropriate use of forecasting mechanisms; the desirability of long term hedging, etc. However, the core and crux of the matter is found within the structure of the COSG Agreement (E279;26, Vol V) as presented to the PSC. Boiled down to its essentials, this is how the COSG Agreement would work:

THE COSG AGREEMENT

A. The Concept. BHUH proposes to enter COSG Agreements with its regulated subsidiaries in Colorado, Iowa, Kansas, Nebraska, South Dakota and Wyoming (E101; 14:17-19: 26, Vol III). Hedge Targets would be established for each of the utilities, representing, as originally proposed, 50% of each of the utilities forecasted annual firm gas demand each year (E279, 3;26, Vol V). An unregulated subsidiary generically described as COSGCO would acquire reserves based upon the acquisition criteria adopted as part of the COSG Agreement and would commence production and drilling under five year drilling plans, also based upon criteria adopted as part of the COSG Agreement, to meet the Hedge Targets (E272; 2). COSGCO would not, however, directly sell this gas to the utilities to fulfill the respective utilities firm gas demand (62:18-63:7). Rather, COSGCO would sell the hydrocarbons (natural gas and liquids produced from the properties) on the open market (E101; 15:8-12; 26, Vol III). The amount received from those sales represents the COSGCO revenue (E279; 2). From that is deducted the COSGCO OpEx, which are the typical operating expenses incurred by a production Company including all cost of management, attorneys, consultants, unaccounted for gas costs, depreciation, amortization, depletion, taxes, direct charges from BHUH and its affiliates for time spent providing services for the benefit of COSGCO, etc. (E279, 2; 26, Vol V). The resulting amount is net income, which can be a positive or negative figure. From net income is deducted the allowed return on equity (Allowed ROE") "plus or minus" 100 basis points times the Invested Equity (E279, Exhibits D and E; 26, Vol V).

B. Return on Equity. The Allowed ROE is defined by the COSG Agreement as an average of the "annual return on equity in all gas and electric utility rate cases for the calendar year, as subsequently reported by Regulatory Research Associates..." The "plus or minus" comes from whether or not the actual ROE exceeds or falls below the Allowed ROE. Thus, if the Allowed ROE is established at 9%, and if the actual ROE exceeds 9%, COSGCO can earn up to one additional percent (100 basis points) and then the Company's rate payers might see a credit; if the actual ROE falls below the allowed ROE, then the allowed ROE may be reduced by up to 100 basis points, e.g. from 9% down to 8%, but the Company's ratepayers will pay a hedge cost that makes COSGCO whole as regards all of its operating expenses and the Allowed ROE (minus 100 basis points) times its Invested Equity.

C. The Monitors. All of the moving parts associated with the Company's proposal will theoretically be monitored by a Hydrocarbon Monitor whose function is to assure that property acquisitions meet the acquisition criteria and that drilling plans meet the drilling criteria (E279, 6;26, Vol V). An Accounting Monitor is included to assure that all of COSGCO's calculations in determining hedge costs and credits are correct (E279, 6;26, Vol V). The monitors will be retained by BHUH, with, admittedly, the concurrence of the Commission (E279, 6;26, Vol V), but that means that these monitors must also be concurred in by the other participating jurisdictions whose similar programs will be similarly monitored by these consultants. There is little need to go into the detail of the limitations upon these monitors at this point, but suffice it to say that upwards of half a billion dollars of potential capital investment (98:22-99:15) will be based upon rather expedited reviews by both the monitors and the Public Service Commission.

D. Hedge Costs and Credits. The hedge costs or hedge credits will be flowed through the Purchased Gas Cost Adjustment (PGA) clause to the ratepayers just as the cost of gas is being flowed through to the ratepayers now (E101; 19:11-12; 26, Vol III). The PSC will have little real control after these mechanisms are put into place since the Allowed ROE, which can change every year, will not be subject to PSC approval or review after the COSG Agreement is inked nor will the PSC have any real control over the COSG operating expenses since these costs will not be subject to any significant separate prudency review through any rate case, etc. during the life of this project. No audit is called for under this agreement; rather, the only item specifically provided for is an assurance report prepared by the Accounting Monitor regarding the accuracy of BHUH's calculations under the COSG Agreement for each calendar year.

E. Termination. Finally, the COSG Agreement is intended to be in effect from the Effective Date until the wells in the Properties are plugged and abandoned (anywhere from 20-30 years depending on the characteristics of the well). While there is an early termination provision in Section 6.2 of the COSG Agreement (E279; 26, Vol V), this is by no means as simple as providing a notice, allowing a period of time to expire, and gracefully exiting from the program. Rather, early termination is only triggered by a termination order issued from the PSC to the Company. (Id.) BHUH will then cause COSGCO to sell, as soon as practical, an interest in the Properties that is functionally equivalent to the terminating utilities percentage share for the calendar year. (Id.) However, no sale shall occur until the remaining utilities, (other BHUH subsidiaries), have approved the interest to be sold and the terminating utility has approved the sale price. (Id.) While witnesses on behalf of the Company have argued that this clause does not really mean what it says (96:4-97:3), the plain words would appear to require sale of an interest to be approved by all of the other participating utilities. In any event, if the interest to be sold cannot in fact be sold, the utility remains as a participant in the COSG Program.

That is essentially the program that the Company is asking the Commission to review and bless. In a nutshell, for the six jurisdictions initially proposed to be included within this Agreement, there could be upwards of half a billion dollars invested in reserves and placed into production by COSGCO. COSGCO will be paid all of its operating expenses and a return on equity (plus or minus 100 basis points) year in and year out; COSGCO will not lose money regardless of what occurs in the market place. All of COSGCO's risks of underproduction, dry holes, counterparty risks, bad debt, lawsuit, or whatever else might befall COSGCO, are not COSGCO's risk ultimately; they are the ratepayers'.

STATEMENT OF ISSUES

The Public Advocate believes that the issues presented to the Commission for determination can be synthesized as follows:

1. Whether the Company's proposed Cost of Service Gas Program unduly shifts the risk of excessive costs and inappropriately guarantees cost recovery of an unregulated affiliate's investment and operating costs to ratepayers.
2. Whether the Commission can or should approve tariff sheets authorizing the Company to recover amounts incurred under a COSG Program from ratepayers through its PGA clause.

3. Whether the Company's request to establish a return on equity predicated on an average of returns on equity in utility rate cases reported in regulatory research associates is unreasonable and usurps the jurisdiction of the PSC.
4. Whether the proposed supervisory and procedural safeguards as outlined in the COSG Agreement provide adequate protection to ratepayers.
5. Whether the Company has made a showing of significant potential volatility of natural gas prices in the future so as to justify approval of a COSG Program that will bind the Company for 20 or more years.
6. Whether the Company's Application is motivated by a desire to insulate ratepayers from price volatility or is instead motivated by the interests of its stockholders.

AN "OPINION EVIDENCE" DIGRESSION

The Public Advocate will address the above issues seriatim. However, before doing so, it seems appropriate to interject some prefatory remarks upon the evidence presented by the Company in this proceeding. The PSC received a wealth of reports and forecasts, and heard from very experienced and knowledgeable Company witnesses including Mr. Ivan Vancas, Mr. John Benton, Mr. Adrien McKenzie, Mr. Aaron Carr, and others. The Public Advocate believes that their evidence was presented in the best of faith and fairly represented the Company's position. However, except to the extent that this testimony represented historical data, or explained the intended functioning of the COSG program, it constituted opinion testimony, albeit by experts in the field. The PSC heard, variously, opinions about the ability to acquire the necessary reserves for the COSG program at extremely reasonable prices, that this was the ideal time in which to effect such acquisitions, that gas prices will likely rise in the future, that drilling costs will not rise at the same rate as the price of gas, etc. All these predictions may or may not prove true, but, as you know, the Public Advocate made little effort to directly controvert these opinions; it is not necessary to controvert what is essentially speculative evidence. Certainly concrete information regarding drilling prices, current costs of gas, etc. are matters in which these witnesses are well-versed. However, when it comes to the forecasting of the price of natural gas, the volatility thereof, chances of recovering gas from any given field, these are all opinions and, regardless of whether the testimony is controverted or not:

"Triers of fact are not required to take opinions of experts as binding upon them. . . [D]etermining the weight that should be given expert testimony is uniquely the province of the fact finder." *Vredeveld v Clark*, 244 Neb. 46, 51, 504 N.W. 2^{nd} 292, 296 (1993).

More particularly, as we get into the specific issues, it will be apparent that predictions regarding future conditions are inherently and necessarily suspect.

ARGUMENT

I.

The Company's proposed cost of service gas program unduly shifts the risk of excessive costs and inappropriately guarantees cost recovery of an unregulated affiliate's investment and operating costs to ratepayers.

Despite the protestations of the Company's witnesses to the contrary (280:5-22), there is little real argument that the COSG-Agreement shifts all risk of loss, with the limited exception of the 1% plus or minus on the return on equity, to Nebraska ratepayers.

COSGO produces the gas and then sells it into the open market (not to the utilities). The idea behind the program is that, having acquired producing and other reserves from owners willing to sell cheap because of today's low gas prices, COSGO (and presumably the ratepayers) will benefit if and when the price of gas exceeds the cost of acquiring the reserves, plus the operating costs, plus what is really a guaranteed rate of return of some amount that will be plus or minus 100 basis points, depending upon just how well the program does. The idea, the "cost of service" lies in the fact that BHUH is confident that it can get these low cost reserves and then maintain reasonably low prices of production, that is, the production costs will not rise over time as much as would the commodity cost (the gas). If this all works out as anticipated, ratepayers do not enjoy a fixed cost of gas into the future; rather, they get the possible benefit of the "hedge credit." On the assumption that gas prices rise enough, then the difference between what COSGO is able to sell the hydrocarbons for and what the formula allows COSGO to recover is what will constitute the "hedge credit"[1]. This is all well and good, if the price of gas rises sufficiently such that more revenue is earned than what COSGO takes out of the program. The revenue must be sufficient that, after taking out all COSGO OpEx[2] and Allowed ROE, there is a remainder.

The Allowed ROE earned by COSGCO will be based upon the average of the electric and gas utility cases of the previous year, as described above, and it will be plus or minus 100 basis points depending upon whether the actual rate of return on equity is more than 100 basis points greater than the Allowed ROE. For instance, if the Allowed ROE was shown to be 9% by the average, and Actual ROE exceeded Allowed ROE by 100 basis points or more, then COSGO

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[1] To get the "Hedge credit or Hedge cost," you first take all Revenue earned by COSGO and deduct all the operating expenses; that gives you Net Income. Then you deduct the amount resulting from multiplying the Allowed ROE, plus or minus 100 basis points, times the Invested Equity (60% of Investment Base). Then you gross up for taxes. The result is the Hedge Credit or Hedge Cost.

[2] COSGO OpEx as defined in the Agreement which is essentially all operating expenses including depletion, dry hole costs, etc.

would be earning a 10% return on equity times its invested equity, which is artificially established in the agreement at 60% of the investment base.

Under these circumstances, to the extent that there is net income exceeding the above-referenced deductions, the ratepayers are given a hedge credit that flows through the PGA clause.

However, if there is a bad year and the cost of natural gas remains flat, as it has for the past two years, then there likely will be insufficient revenue to cover the COSGO OpEx and provide COSGO its Allowed ROE. Under these circumstances, we still take the revenue obtained from selling the COSGO gas into the market and, from the revenue on such sales, we deduct all of COSGO's OpEx which gives us net income which may or may not be a positive number. From that net income, we then deduct COSGO's Allowed ROE, which in this case was presumably less than the actual return on equity. This means that we deduct 100 basis points from the Allowed ROE, multiply that times the Invested Equity (60% of the investment base), deduct that from Net Income and then do the tax gross-up. The resulting negative number is passed through the PGA clause to the ratepayers as a hedge cost.

What do we see from the above? Clearly, COSGO never seriously incurs any risk. All of the risk, with the exception of obtaining 1% plus or minus of what is an average rate of return on rate cases from the past year, is passed on to the ratepayer. If production is down, if gas wells explode, if environmental regulations make gas production unprofitable, if a counter-party defaults, if anything happens that negatively affects COSGO, that negative effect, in terms of its dollar cost, is passed on to the ratepayer. COSGO is constantly and consistently made whole, with its operating expenses paid and a rate of return paid, with the rate of return fluctuating outside the control of the Public Service Commission. The COSGO risk is simply forfeiture of a possible 100 basis points of return on equity.

This is compounded, of course, by the fact that an artificial cost of capital structure is proposed consisting of 40% debt and 60% equity. Recognizing that the Company has suggested this is adjustable, nevertheless the application before you reflects the 40/60 ratio and even if this is adjusted to reflect more nearly the cost of capital structure approved for the Company (48/52 debt to equity) in its last rate case, this still doesn't circumvent the fact that COSGO is so structured under this arrangement as to never lose money.

Further, BHUH proposes to use another affiliate, Black Hills Exploration and Production, as an entity that will stand either as an operator or advisor to COSGO. Thus, the Black Hills corporation family profits by providing services to COSGO which, again, passes these costs on through to the ratepayer through the PGA clause. Whether this is beneficial or not is, to some extent, irrelevant. The fact is that the PSC will have no real control over the costs incurred by COSGO; that is, once the agreement is in place, COSGO is free to proceed to acquire and begin production of natural gas, and no rate case for COSGO or Black Hills Exploration and Production will be coming before the PSC for a thorough review of the prudency of the costs and expenses incurred. Yes, there are supposed to be monitors, but the inadequacy of that arrangement will be discussed in another part of the brief. Suffice it to say, that there are no real serious controls over the costs that can be incurred, no real regulations or guidelines to say that this particular cost or that particular cost is not prudent. Indeed, and again this will explored in greater depth in another part of the brief, determinations of prudency in the area of exploration and production are light years away from a utility commission's well-grounded and precedent-driven determinations of prudency (used and usefulness, weather normalization, and other factors) that are considered in a rate case proceeding, e.g., who is really going to tell COSGO that it shouldn't have contracted for that second and third rig as part of a drilling program?

The idea of buying into natural gas reserves based upon costs of acquisition that will likely be depressed because of today's low cost of natural gas ($1.73 per MMBtu at Henry Hub in March, 2016) (E274:26, Vol V) has some definite appeal. Indeed, if the price of natural gas over the next few years not only rose, but was the subject of fluctuations of the nature that were seen in the first decade of the twenty-first century, then ratepayers might actually see real value from this program. However, the problem is that no one can predict with certainty what the price of natural gas is going to do twenty years in the future, no one can really say what technological advances in the natural gas industries may occur in the next twenty years, and no one can foresee what environmental concerns may arise in the next twenty years, i.e., gas may go the way of coal and whale oil. Indeed, the best prognosticators are often wrong. Take, for example, the Company's own witness, Julia M. Ryan who, at the time of submittal of her report in September of 2015 stated:

"In its May 2014 report, Wood McKenzie's analysis of the major shale plays in North America illustrates break-even prices of $3-5 per mcf for these low cost shale gas resources. This suggests the price cannot go much lower because the market is already close to break-even levels. Aether direct testimony 11:811."

At that time, the Henry Hub price of gas was around $2.50 mcf; nevertheless, the price of gas continued to drop to $1.73 per mcf, in March (E274; 26, Vol V). See also, *U.S. Natural Gas: Fundamental and Outlook for 2016* where it is stated:

> "A poorly kept secret is the that the U.S. Natural Gas Industry has been able to survive despite what was often presented by analyst and industry executives as unsustainably low natural gas prices. In fact, not only did the industry survive, it managed to grow production at a brisk pace." (E136, attachment to DR-60z; 26, Vol III).

This unfortunately proves the truth of the observation in the NRRI Research paper styled, *Vertical Arrangements for Natural Gas Procurement by Utilities: Rationales and Regulatory Considerations* (Report No. 16-04, February, 2016), hereinafter the "NRRI Report" (E278; 26, Vol V). The researcher, Mr. Ken Costello, noted:

> "In their proposals for [utility ownership of gas reserves] utilities forecast natural gas prices decades out in time (e.g. 10 to 40 years) which are highly speculative, illogical (as discussed later) and practically meaningless for Commission decision making." Id. at page 5.

Nor can we take comfort in the risk calculations as evidenced by the model attached to the Direct Testimony of Aaron Carr (E106:26, Vol III) as Exhibit AC-2. As attached to the Application filed in September of last year, the model indicated that a hedge credit would not be realized until December of 2020, which means that the ratepayers wouldn't break even until December of 2022 (see Tab: **Financial Model**, line 26). Contrast this with the same financial model using slightly different gas costs that was provided in June of 2015 (E275,6:26, Vol V) indicated that the hedge costs would be considerably lower with the hedge cost disappearing in December of 2018.

Mr. Michael McGarry, in his Direct Testimony (Highly Confidential Version) (E202:26, Vol V) used an update of the forecast of natural gas market prices based on the current EIA data and, using the AC-2 model, found that ratepayers would theoretically pay $4.6 million in hedge costs overall on an net present value basis over the 10 year modeling forecast (E202, 33:4-34:3, 26, Vol V). The point is that, even under the modeling by the Company, the risks and reward are highly dependent upon the unknown future and virtually all of those risks are shifted to the ratepayer.

With respect to the potential risks to ratepayers in approving this type of vertical integration, the NRRI Report (E278:26, Vol V) is instructive. It states, regarding the imbalanced risk allocation regarding utility ownership of gas reserves that:

> "From the perspective of utility customers, vertical integration seems to be a high-risk strategy. Under most proposals and actual plans, utility customers would be shouldering much more risks than utility or holding-company shareholders. Vertical arrangements create several risks. They include: (1) gas production operating cost, (2) level of gas reserves and production (e.g. "dry holes"), (3) liability and incomplete contractual arrangement (leaving room for opportunism or, more generally, bad behavior), (4) counter-party risks, and (5) regulatory induced risks, derived from less than full commission commitment, regulators knowing little about the upstream side of the gas business and having to evaluate complex contract provisions....
>
> After reviewing different vertical-arrangement plans, it seems clear that customer risk is excessive relative to utility or holding company risk. It is somewhat ironic that the major apparent reason for vertical arrangements is to reduce upside price risks to utility customers but, in the process, utilities are asking customers to take on new risks..." Id. at page 44.

Would Nebraska be alone in concluding that programs such as the COSG unfairly shift risk to the ratepayer? The Company's witness, Mr. Ivan Vancas, pointed out that Florida Power and Light sought and obtained approval from the Florida Public Service Commission to invest $191,000,000 in a gas reserve program, and also noted that Washington Gas, a Virginia utility, was entering into a $126,000,000 purchase and sale agreement to acquire 22 producing natural gas wells in Pennsylvania (E101,12:19-13:11; 26, Vol III). What has been the reaction of those jurisdictions?

In *Application of Washington Gas Light Company for Approval of a Natural Gas Supply Investment Plan* (Case Number PUE-2015-00055) the Virginia State Corporation Commission on November 6, 2015 rejected the plan. In looking at all the risks, the Commission stated:

> "Under the specifics of the Proposed Plan, the potential harm to customers is too great when compared to the potential benefits. The Company admits that, from the moment the Commission approves the Plan as proposed in the

application, WGL's customers would bear *all* of the Plan's risks, and WGL (and its shareholders) would bear none of those risks. Under such an unbalanced arrangement, an analysis of potential risk, in evaluating the Plan as a whole, becomes particularly relevant to a finding on public interest.

In this regard, the Company's customers bear the risks associated with production volumes from these wells falling short of WGL's projections. WGL witness acknowledged that his estimates of the natural gas reserves and production volumes are just that – estimates – and it remains a risk that production volumes could fall below the levels needed for customers to reap any savings benefit. . . .

The Company's customers also bear the risk if WGL's twenty-year price forecast is overstated. . . . No party contested that forecast confidence generally decreases as the forecast period extends, and, in this instance, the twenty-year plan requires a twenty-year forecast. We find that the evidence demonstrates credible concerns regarding sole reliance on the specific U.S. Department of Energy's Energy Information Administration ("EIA") forecast chosen by the Company. . . .

The Company's customers also bear the risks associated with certain variable costs. That is, only the commodity cost is fixed over the twenty-year life of the Plan. There are numerous variable costs that are not fixed, including operation and maintenance expenses, future regulatory compliance and taxation costs, and changes in WGL's cost of capital."

More recently, the Supreme Court of Florida, in *Citizens of the State of Florida vs. Art Graham, et al.*, _____ So. 3d ____, 2016WL2908155 (2016) overturned the order of the Florida Public Service Commission approving what Florida Power and Light asserted would operate as a long-term physical hedge against the market volatility of natural gas prices used to provide electric service to FPL's customers. The Florida Court, in rejecting the program, noted:

'Permitting advance recovery of FPL's investment in the Woodford project's exploration and production of natural gas will not pay for the cost of actual fuel. It will provide recovery, instead, for investment, operation, and maintenance and operation of assets that will provide access to an unknown quantity of fuel in the future. It is impossible to know what the costs of the natural gas will be until it is actually produced. There is more uncertainty from this investment rather than less. Therefore, it cannot be characterized as a physical hedge.

> Additionally, under FPL's proposal for the Woodford Project, ratepayers (not FPL) bear the risk of natural gas volatility and all of the production risks. If the production cost for extracting natural gas from the Woodford wells, including profit paid to FPL on its capital investment, is less than the natural gas market price, the ratepayers will benefit. However, if the production cost of extracting natural gas from the Woodford wells is more than the natural gas market, the ratepayers do not benefit but will instead suffer a loss. The monies spent on the Woodford project are not a mere pass-through, like other fuel expenses, because FPL will earn a return on its capital expenditures. Accordingly, the Woodford project is a guaranteed capital investment for FPL; it is not a hedge to stabilize fuel costs." Id. at 4.

The above quote could be utilized almost verbatim in an order rejecting the Company's proposal before the PSC today. The Florida Court pinpoints the problem exactly. The COSG program is a guaranteed capital investment for BHUH. It is proposing to improperly use the PGA clause, not as a pass-through of actual costs, but as a pass-through for profits to one of its affiliates. That someone, somewhere, will make a profit on the sale of natural gas to the Company for delivery to its customers is no answer. It is the possibility or even the perception that the affiliate relationship could be exploited is the concern. To assure a return on equity to an affiliate and ultimately to BHUH, and to assure the payment of costs for services to COSGO by other Black Hills affiliates, is an improper use of the PGA clause.

Finally, as the PSC is aware, the Colorado Public Utilities Commission dismissed, on motion of the Office of Consumer Council, the Colorado application for a cost of service gas program filed by Black Hills/Colorado Gas Utility Company (CPU Proceeding No. 15-0867(G). Not only does this raise the question of the viability of the program in general, and the apparent concerns of Colorado regarding the program in particular, but it also casts into doubt the modeling conducted by the Company regarding the economics of the Program as presented to the PSC. Commission Attorney Nicole Mulcahy inquired about the effect of Colorado not participating in the Program. She questioned Company witness, Aaron Carr as follows:

Q: Mrs. Mulcahy: "But isn't the percentage of what Nebraska's ratepayers are going to be expected to cover for the cost of this going to change if 26% of this is now going to be borne by the other states that stay in it?"

A: (Mr. Carr) "It would."

Q: Mrs. Mulcahy: "Do you know what that would be if Colorado does ultimately not get in? They are the largest participant, so that kind of effects the other states quite a bit."

A: (Mr. Carr) "It does. And that is an interesting question that I don't know that we fully got to the bottom of since the order hasn't even yet come out." (E364:23-365-12)

In sum, the answer to Issue No. 1 is simple: the COSG program improperly transfers risks to the ratepayers, in effect transforming them into little more than the holders of futures contracts. And yes, the program inappropriately guarantees a return on equity to an unregulated affiliate of BHUH.

II.

The Commission should not approve tariff sheets authorizing the Company to recover amounts incurred under a COSG program from ratepayers through its PGA clause.

The Company's proposed use of the Purchased Gas Cost Adjustment (PGA) clause (Index No. 8 of the Black Hills Energy Nebraska tariff) to flow hedge credits or hedge costs through to ratepayers is an inappropriate use of the PGA clause. Whether the PSC can even entertain such a proposal based upon the statutory provisions regarding gas supply cost adjustments is debatable. Neb. Rev. Stats. 66-1854 provides, in part, that:

> "(1) The Commission shall allow jurisdictional utilities to implement and thereafter modify gas supply cost adjustment rate schedules that reflect

increases or decrease in the cost of the utility's gas supply such as: (a) federally regulated wholesale rates for energy delivered through interstate facilities, (b) direct costs for natural gas delivered, or (c) costs for fuel used in the manufacture of gas. Such costs may, in the discretion of the Commission, include costs related to gas price volatility risk management activities, the cost of financial instruments purchased to hedge against gas price volatility, if prudent, and other relevant factors. . . ."

Clearly, the proposed hedge costs or hedge credits have nothing to do with gas actually delivered, nor do they have anything to do with costs for fuel used in the manufacture of gas. Rather, if approved at all, the COSG Program would have to fit within the provisions regarding hedging activities. However, the PGA is intended to serve as a mechanism for reflecting the costs of natural gas and pipeline transportation costs on a dollar-per-dollar basis. (See, 38A CJS Gas as Sec. 112 Purchased Gas Adjustment Clause.) It is not intended to be a pass-through of any profit by the utility on the cost of gas or, presumably, on hedging activities authorized by the Commission.

As the Supreme Court of Florida said in *Citizens of the State of Florida vs. Graham*, supra,:

"The fuel cost adjustment clause is a cash flow mechanism to allow utilities to recover costs for unanticipated changes in fuel costs between rate making proceedings. See Gulf Power Co., 487 So. 2nd at 1037 ("Fuel adjustment charges are authorized to compensate for utilities' fluctuating fuel expenses. The fuel adjustment proceeding is a continuous proceeding and operates to a utility's benefit by eliminating regulatory lag."). The mechanism also permits utilities to recover actual costs of financial derivatives and physical hedges that help prevent price shocks from volatile fuel costs. However, regulated utilities through the fuel clause do not earn a return on money spent to purchase fuel. Likewise, while the costs of hedging contracts are pass-through costs, utilities through the fuel clause do not earn a return on the cost of hedging positions purchased. . .

Permitting advance recovery of FPL's investment in the Woodford Project's exploration and production of natural gas will not pay for the costs of actual fuel. It will provide recovery, instead, for investment, operation, and maintenance and operation of assets that will provide access to an unknown

> quantity of fuel in the future. It is impossible to know what the costs of the natural gas will be until it is actually produced. There is more uncertainty from this investment rather than less. Therefore, it cannot be characterized as a physical hedge." Id at 3-4.

And further, the Florida Supreme Court concluded:-

> "The monies spent on the Woodford project are not a mere pass-through, like other fuel expenses, because FPL will earn a return on its capital expenditures. Accordingly, the Woodford project is a guaranteed capital investment for FPL; it is not a hedge to stabilize fuel costs." Id at 4.

In sum, the Public Advocate suggests that approval of a tariff that would flow hedge costs and hedge credits through the PGA clause is outside the terms of the statute and beyond the authority of the PSC. This is not a simple flow-through of the cost of gas or even the cost of hedging instruments. Rather, it takes us back to the era in which a gas companies' integrated activities included, not only transmission and distribution, but production and sale of the commodity to the ratepayer with a resultant return to the utility on the commodity itself. What is proposed is an improper use of the mechanism that was designed to evolve away from that vertically integrated structure.

III.

The Company's request to establish a return on equity predicated on an average of the annual rate of return on equity in all gas and electric utility rate cases reported in Regulatory Research Associates, and based upon a 40 debt/60 equity cost of capital structure, is unreasonable and usurps the jurisdiction of the PSC.

The proposed COSG agreement provides that the "Allowed ROE" that COSGO will earn shall be:

> "The average of the annual return on equity in all gas and electric utility rate cases for the calendar year, as subsequently reported by Regulatory Research Associates . . ." (E279, 2; 26, Vol V)

This "Allowed ROE" is applied to a "Cost of Capital" structure which, according to the COSG Agreement "shall be an imputed weighted average consisting of forty-percent (40%) Allowed Cost of Debt and sixty-percent (60%) Allowed ROE" (E279, 2; 26, Vol V).[3] Thus, the "invested equity" to which the Allowed ROE is applied represents 60% of the "investment base". The "Allowed ROE" times the "invested equity" represents the return that COSGO will make annually (plus or minus the 100 basis point band as discussed above). Once the agreement goes into effect, these formulas are set, and the PSC has no further input into determining whether the Allowed ROE is appropriate or not. This was recognized by the Company's own witness, Adrien McKenzie. (314:20-315:10)

Use of an average return on equity established by other commissions for utilities around the country may or may not reflect a reasonable rate of return for a jurisdictional utility in Nebraska. Whether it does or not, the PSC will not be able to revise it one way or the other; it will be determined simply and solely by the formula. If this were a return on equity being established for a jurisdictional utility, this would in all likelihood be unconstitutional since utility rate making is a legislative function, *Locks v Mental Health Board of Polk County*, 202 Neb. 106, 109, 274 N.W. 2d 141, 144 (1979), and this writer would suggest that the PSC could neither delegate nor abdicate that power to a private entity. "It is fundamental that the Legislature may not delegate legislative power to an administrative or executive authority," *Smithberger v*

[3] The Public Advocate recognizes that the Company has suggested that it would be willing to revise the agreement to reflect a 50/50 ratio debt to equity; however, that is not what is before the Commission in the application and, as the Public Advocate's witness indicated, we did not have time to study that ratio or respond to it. Nevertheless, we recognize that as a good faith effort to address this concern.

Banning, 129 Neb. 651, 262 N.W. 2d 492 (1935). Whether the PSC blesses a contract between the Company and with an unregulated affiliate that contains a floating "Allowed ROE" may be less problematic, but obviously raises a concern. As Mr. Michael McGarry, the Public Advocate's expert witness testified:

> Q. Do (sic) does that not allay your fear relative to the ROE?
>
> A. No.
>
> Q. Your concern?
>
> A. No, because as I said, I didn't materially change the answer when I corrected the testimony. The concern is having the ROE set based on other utilities that are outside the purview of the Commission. That is the primary concern. (381:16-24)

Thus, going forward, the Commission will have no control over the return on equity of COSGO or on its capital structure, which will be set in stone by this agreement. Whether the capital structure is 60/40, or 50/50 as the Company has suggested might be acceptable, this proposed structure is rigid and, over the course of twenty years, very likely unreflective of reality as it relates to COSGO's particular situation.

IV.

The proposed supervisory and procedural safeguards as outlined in the COSG agreement fail to provide adequate protection to ratepayers.

(a) The COSG Agreement includes provisions related to review of acquisition of reserves and drilling plans by a Hydrocarbon Monitor. It further provides for the filing of an assurance report by an Accounting Monitor regarding the accuracy of BHUH's calculations under the COSG Agreement during the calendar year. The Accounting Monitor and

Hydrocarbon Monitor are retained by BHUH; they must be mutually agreeable to BHUH and the regulatory bodies of the participating utilities. However, the fact remains that they are, pursuant to Sec. 2.1 of the COSG Agreement, indeed retained by BHUH (E279, 6; 26, Vol V) and there is little in the Agreement that indicates, after retention, how they are evaluated, who can terminate the relationship, and indeed exactly how we get six different jurisdictions and BHUH to collectively address anything regarding the Monitors' activities, compensation, or work product. Clearly, this is not a typical situation in which the PSC would retain its own consultant with a clear and direct line of communication and reasonable expectation of loyalty to the goals and needs of the PSC.

(b) The acquisition of properties and establishment of drilling plans are subject to review by the Hydrocarbon Monitor. For each acquisition and drilling plan, a substantial amount of information is provided to the Hydrocarbon Monitor, pursuant to Sections 4.2 and 4.4 of the COSG Agreement (E279; 26, Vol V), but unfortunately the specific terms of the Agreement, require that, within 10 calendar days following receipt of all the information, the Hydrocarbon Monitor shall issue a written report to BHUH, the utilities, and the PUC's regarding whether the proposed acquisitions (Sec. 4.3 of the COSG Agreement) or drilling plans (Sec. 4.4 of the COSG Agreement) meet the Acquisition Criteria and Drilling Criteria as set forth in Exhibits A & B to the COSG Agreement. Note that, as regards the authority of the Hydrocarbon Monitor, the Hydrocarbon Monitor <u>must</u> approve the proposed acquisition or the proposed drilling plan if it meets established criteria (E258, 1; 26, Vol V).

Thereafter, according to the Agreement, if "no PUC reaches a contrary determination in a formal <u>adjudicative proceeding</u> concluded within 60 calendar days after receipt of the Hydrocarbon Monitor's report," then the proposed acquisition is deemed a Property under the terms of the COSG Agreement, the drilling program becomes the drilling plan, and COSGO develops the property until the next five-year anniversary. (Sec. 4.3 of the COSG Agreement.)

Ten days for the issuance of reports by the Hydrocarbon Monitor on acquisitions and/or drilling plans is unrealistic. While the Company says that the Hydrocarbon Monitor will have access to the information before the 10-day period begins to run, that is not what the COSG Agreement says. It is plausible that acquisitions must take place quickly if there is a willing seller who wants to close on a particular reserve interest. Indeed, that is most certainly how the real world works. Nevertheless, it is worthwhile to point out that Mr. John Benton, in his testimony, noted that the affiliate of Black Hills Corporation, Black Hills Exploration and Production, had, before its present financial difficulties, employed more than 60 professional engineers, geologists, field personnel, land and title professionals, petrochemists and petrotechs (192-22 - 193-12). At least a third of these would be involved in acquisition activities (193:21 - 194:6).

Further, the Company's witness, in response to a Data Request as to what professional expertise one would utilize in making a gas field acquisition responded:

> In general, a typical gas exploration and production company would utilize its in-house land, environmental, regulatory, geo-science, and engineering expertise to evaluate a potential acquisition. It may also solicit similar expertise from third-party consulting firms, such as environmental firms and third-party reservoir engineers, as part of the evaluation process. (E255, 1; 26, Vol V)

The point is, that a substantial number of professional people over an awful lot of time will look at the acquisition of a costly asset such as producing reserves. To suggest that all of the information will be transmitted to the Hydrocarbon Monitor who, within 10 days, must determine whether or not it meets the Acquisition Criteria and submit a report to the regulatory bodies seems a bit much.

Further, the regulatory bodies, upon receipt of the Hydrocarbon Monitor's report, have sixty days in which to conduct a "formal, adjudicative proceeding" if the Hydrocarbon Monitor's report is questioned. Surely the Company understood just what it meant for the PSC to conduct a "formal, adjudicative proceeding." Under Commission rules, assuming this would be treated as an application, once notice is given, and time for protest (30 days) is provided pursuant to 29 1NAC1-014.021, and interventions allowed; once experts are retained, reports received, discovery conducted, it is obvious that the 60 days will have long passed. Now, the Company has said that this period could be extended to 120 days for drilling plans and 180 days for property acquisition reviews (387:12-16), but the latter comes with the possible penalty of incurring a termination fee (387:24-388:4). Admittedly, 180 days for review of the proposed acquisition is a more reasonable timeframe. It still leaves hanging the question of just why the agreement requires a "formal, adjudicative proceeding" which, according to reasonable interpretation, would be requiring the PSC to test the acquisition against some legal standard, presumably the Acquisition Criteria appended to the COSG Agreement. Rather than simply giving the PSC the opportunity to turn down an acquisition because of a staff recommendation, a consultant recommendation, or simply because of suspicions regarding circumstances, this would seem to be elevating the determination to a quasi-judicial proceeding in which the Company would be entitled to proceed if it is not shown that the acquisition doesn't meet the Acquisition Criteria.

Further, and as a practical matter, the Public Advocate and the PSC are not equipped in and of themselves to make any sort of evaluation of either acquisitions of natural gas reserves or drilling plans. These are far and away outside the qualifications and experience, for the most part, of utility commissions that are rate making and regulatory bodies, not investment companies. Indeed, in the NRRI Report (E278; 26, Vol V), the writer notes:

> "Vertical arrangements create several risks. They include:...(5) regulatory induced risks, derived from less than full commission commitment, regulators knowing little about the upstream side of the gas business and having to evaluate complex contract provisions." Id. at 44.

(c) As regards the Accounting Monitor's, the formal function of the Accounting Monitor is fully exhausted after providing an assurance report regarding the calculations made by BHUH regarding the COSG Agreement (see Sec. 5.5 of the COSG Agreement). As even the Company's witness, Mr. Chris Kilpatrick testified:

> Q. Ok. So the function of the accounting monitor under this agreement is once a year to check the calculations of BHUH, right?
>
> A. And provide an assurance report, correct.
>
> Q. Right. And if the calculations by BHUH are accurate, then the accounting monitor sends that report on to the Public Service Commission and the utility?
>
> A. Yes.
>
> Q. Okay. Now is there anywhere in this agreement that says what the Public Service Commission is entitled to do with that report?
>
> A. Not that I'm aware of. (269:24-270:11)

The Accounting Monitor would appear to be a toothless tiger. The assurance report is provided to the PSC, but nowhere are there included any remedies for miscalculations, remedies for cost overruns, excessive costs, or whatever. Nothing in the agreement authorizes any further financial review by way of an audit or otherwise. While the Company says that all the books and records will be open, auditing isn't permitted or required, and if penalties or remedies are not provided for accounting issues, this would seem to be a significant deficiency.

The upshot is that reviews by a Hydrocarbon Monitor retained by BHUH to cover all participating jurisdictions, who must perform its work within 10 days, and permitting rejection of acquisitions and drilling plans only after formal, adjudicative proceedings is certainly not the best way to protect the interests of Nebraska ratepayers. The assurance report by the Accounting Monitor is, likewise, a weak supervisory tool with which to oversee a complex and expensive program.

V.

The Applicant has not made a showing of significant potential volatility of natural gas prices in the future such as to warrant approval of a COSG Program that will bind the company for 20 or more years.

In response to a data request in which the Company was asked to describe the goal of the COSG Program, the Company responded as follows:

> "The goal of the COSG Program is to provide long-term price stability for a portion of the supply purchased for customers through a physical hedge from owned reserves at the cost of production. The cost of production is primarily driven by the acquisition cost of the reserves, which are at one of the historical low points, and the cost to drill and complete wells. The Company further anticipates that customer will have a reasonable opportunity for savings over the life of the reserves compared to market purchases calculated at the MVP of the COSG Cost Forecast and the Long-Term Market Price Forecast of Gas Prices." (E227, 1; 26, Vol V)

Thus, the purpose of the Program is not so much to provide low cost gas to the ratepayer, but to limit price volatility, a laudatory goal. However, other than pure speculation as to gas prices moving upward in the future, and backward glances at spikes in the price of gas occurring in the past, there is little to support the idea that this program is necessary to maintain price stability.

The US Energy Information Administration graph (E274, 1; 26, Vol V) shows Henry Hub Natural Gas Spot Price amounts from 1997 through 2016. It is apparent that there were significant spikes in the price of natural gas occurring at the time of the 9/11 terrorist attack, the 2006 Katrina Hurricane, and the 2008 Recession. However, since 2010 or thereabouts, the price of gas, while having some limited spikes, has not experienced the type of volatility that was seen in the first decade of the 21st Century.

Nor is this Program predicated upon predicted episodes of volatility. Everything utilized by the Company in demonstrating how the COSG Program would work is based upon forecasts showing a relatively gradual and steady increase in the price of gas over the next 20 years. See, for instance, the two long term gas price forecasts (Table 1) utilized by Company witness Chuck Loomis (E104, 15; 26, Vol III). See also Figure 28 of the Aether Advisors Report (E110, pg. 67 of JRM-1; 26, Vol III).

The program has been modeled on projections that do not anticipate spikes or volatility in the price of natural gas; rather, the models and discussions are all around the fact that the price of natural gas may generally rise.

In contrast, we know that technology, including hydraulic fracturing and horizontal drilling, have been bringing greater certainty and stability to the extraction of gas deposits in the United States with the reasonable anticipation that at least some of the disrupters of supply (off-shore drilling, etc.) may very well be reduced, with concomitant reductions in the price volatility (E107, 4:2-22; 26, Vol III).

Of note are some of the conclusions found in the NRRI Report (E278; 26, Vol V). The researcher notes on page 32 that:

> "Robust, liquid wholesale gas markets have made spot purchases more economical. The striking trend away from long-term contracting during the past 30 years is the result of the natural gas industry becoming more open and competitive. The shifting of trade toward shorter term arrangements, for both gas supplies and transportation, is compatible with the dramatic change in the market environment that has occurred over this period of time."

And further, on page 45 thereof, he states:

> "A final point is that liquid wholesale gas markets (which minimize gas supply risks) plus highly speculative forecasts of long term gas prices severely weaken the case for utility ownership of gas reserves or other vertical arrangements. A long term commitment to buying natural gas from a particular source at a specific price (or range of prices) seems incompatible with an industry that has been successful over the past 25 years in moving away from long term contracts to short term spot and other transactions. These transactions have greatly benefited gas customers and have taken place in a well-functioning market place. As predicted by TCE, vertical arrangements are less defensible when the market for a product or service is competitive and well-functioning." Id. at 45.

The Public Advocate would suggest that there has been no real showing by the Company in this proceeding that market volatility of the type seen in the past is reasonably anticipated to be replicated in the future. This being the prime rationale for proposing the COSG Program, the Public Advocate suggests that a showing has not been made sufficient to warrant approval of the Program based upon that stated goal.

THE COSG PROGRAM WOULD BENEFIT STOCKHOLDERS AND APPEARS TO BE A CURE FOR AN AILING E & P SUBSIDIARY.

Finally, it is obviously necessary to mention the fact that this proposal by the Company is driven, at least in part, by the situation involving Black Hills Exploration and Production, a subsidiary of Black Hills Corporation, and the Black Hills interest in the Piceance Basin in western Colorado, which is part of the Mancos Shale formation. Indeed, the Acquisition Criteria appended to the COSG Agreement as Exhibit A, which establish the characteristics that a property must have to be included in the COSG Program, seem tailor made for the Manco Shale interests (187:1-198:18). Black Hills Corporation has made no secret that it is seriously considering the Manco Shale as a likely property to include in its COSG Program (E277, 18; 26, Vol V). On slide 18 of its 2016 of its Investor Meeting, regarding strategic objectives, it is stated under "Profitable Growth" that it wishes to "capture value upside through Manco Shale development in support of cost of service gas Program."

Further, Mr. Benton has testified that Black Hills Exploration and Production has been losing money for the past five years (212:4-6), is downsizing (193:10-17), and Black Hills has announced in July of last year, announced a strategy to transition oil and gas to primarily support the cost of service gas program. (Exhibit 277, slide 25).

Unfortunately for the Company, these facts certainly cast a shadow on the Application and raise the question as to whether or not this proposal is being driven more by concern for ratepayers or concern for shareholders. Again, as noted in the NRRI Report:

> "Long term vertical arrangements for gas purchases by utilities raise a number of questions about their effect on utility customers and the public interest. There are several reasons for concern, some more serious than others....First, the real motive for utilities seems to coincide with their financial interests. Three motives come to mind: (1) grow the earnings of the utility, its affiliate or holding company, (2) benefit utility customers from long-term hedging, and (3) produce gas cost savings to utility customers. The evidence points to the first motive since the expected gas cost savings estimated by utilities is relatively small and even that may be overstate the true savings (to be discussed; and no good reason exists to believe that the long term hedging benefits to customers warrant the substantial efforts that the utilities have made to consummate joint agreements.

> On the other hand, benefits to utility shareholders and utility holding companies seem more immediate, certain and substantial. For UOGR where the utility places its investments in gas reserves and to rate base, the benefits are much more definitive for the utility than its customers. In fact, the only surety is higher utility earnings." Id. at pages 40-41.

This writer personally does not doubt that the Company officials and witnesses testifying before the Commission have a sincere belief that there is benefit in this Program to the ratepayer. However, there is no doubt that Black Hills Corporation obviously believes that this is a good strategic move for an ailing subsidiary and a profitable use of its interest in the Manco Shale formation. Because of this factual backdrop, the PSC must necessarily apply a higher level of scrutiny in weighing the merits of this Application.

CONCLUSION

It is the position of the Public Advocate that the COSG Program, as proposed, would not be a prudent action as it relates to impact upon ratepayers. It (1) shifts excessive risks of potential losses to ratepayers; (2) improperly makes use of the PGA clause to pass through to ratepayers a rate of return to other affiliates; (3) inappropriately locks in a rate of return for an affiliate that is not subject to PSC review and adjustment; (4) lacks appropriate supervisory and procedural safe guards; and (5) is without a substantial showing that price volatility, which the COSG Program is intended to ameliorate, is likely in the future.

For the above and foregoing reasons, the Public Advocate respectfully asks that the Commission deny the Application of Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, Omaha, in this proceeding.

DATED this 3rd day of June, 2016.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the above and foregoing Post-Hearing Brief of Public Advocate was served electronically on this 3rd day of June, 2016, upon the following:

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