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IN THE MATTER OF THE APPLICATION OF BELLA VISTA WATER CO., INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	Docket No. W-02465A-09-0411
IN THE MATTER OF THE APPLICATION OF NORTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	Docket No. W-20453A-09-0412
IN THE MATTER OF THE APPLICATION OF SOUTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	Docket No. W-20454A-09-0413
IN THE MATTER OF THE JOINT APPLICATION OF BELLA VISTA WATER CO., INC., NORTHERN SUNRISE WATER COMPANY, INC., AND SOUTHERN SUNRISE WATER COMPANY., INC., FOR	Docket No. W-02465A-09-0414 Docket No. W-20453A-09-0414 Docket No. W-20454A-09-0414

APPROVAL OF AUTHORITY TO CONSOLIDATE OPERATIONS, AND FOR THE TRANSFER OF UTILITY ASSETS TO BELLA VISTA WATER CO., INC, PURSUANT TO ARIZONA REVISED STATUTES 40-285.

RUCO'S CLOSING BRIEF

The Residential Utility Consumer Office ("RUCO") hereby files its Closing Brief in the above-referenced cases regarding Bella Vista Water Company, Northern Sunrise Water Company and Southern Sunrise Water Company, (hereinafter referred to as "Bella Vista," "Northern" and "Southern," respectively on a stand-alone basis and collectively referred to as "BVWC" or the "Company" on a consolidated basis.)

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INTRODUCTION

RUCO and the Company have resolved many issues which are identified in Section A of the Brief. RUCO and the Company have not resolved the operating expense issues of central cost allocations or rate case expense. In its application, the Company seeks to allocation $4.1 million in central office costs and seeks rate case expense of $450,000. RUCO recommends $416,000 in central office costs and allocates the costs in a manner similar to methodology approved by the Commission in Black Mountain. RUCO opposes the Company's application for rate case expense and requests that the Commission approve $200,000

All of the parties agree to merge the three distinct corporations, Northern Sunrise, Inc., Southern Sunrise, Inc. and Bella Vista, Inc. into a single corporate entity and to consolidate rates. If the Commission grants the Company's request for consolidation, the parties have no substantial dispute as to capital structure or cost of debt, but do have differences as to the appropriate cost of equity. RUCO requests a cost of equity of 9.0 percent and a weighed average cost of debt of 8.42 percent. If the Commission does not grant the Company's request to consolidate, the parties have unresolved issues on cost of capital, capital structure and cost of debt. For stand-alone rates, RUCO requests that the Commission approve a hypothetical capital structure for Northern and Southern Sunrise and a hypothetical debt of 6.26 percent.

RUCO and the Company adamantly disagree on the issue of the Company's proposed Hook-Up Fee Tariff ("HUF"). The Company's proposal is to book HUF as CIAC only when it has been expended. Simply stated, the Company's HUF proposal would not require HUF funds to be recorded as CIAC upon receipt, which is inconsistent with standard accounting principals and recent Commission decisions. The result would allow the Company to earn a return on non-investor supply capital which is not only contrary to standard ratemaking principals, but bad public policy. The proposal is clearly contrary to the ratepayers' best interests and would for all intents and purposes, redefine CIAC. It would also establish bad precedent. The Commission should reject the Company's HUF tariff proposal.

The above issues, will be more fully discussed below:

A. RESOLVED ISSUES BETWEEN RUCO AND BVWC AND/OR STAFF

RUCO and BVWC have reached agreement on a number of issues, which were initially disputed. Those agreements are as follows:

1. INADEQUATELY SUPPORTED PLANT

RUCO and the Company agree to inclusion of $104,983 of plant.

2. ACCUMULATED DEPRECIATION METHODOLOGY

RUCO and the Company agree with the group depreciation methodology.

3. ACCUMULATED DEPRECIATION CALCULATION

RUCO and the Company agree on the level of accumulated depreciation and RUCO corrected the computation error in its post-hearing schedules.

4. AIAC BALANCE

RUCO and the Company agree on the AIAC balance of $6,781,443.

5. AMORTIZATION OF CIAC

RUCO and the Company agree on the methodology used to determine amortization of CIAC. The amortization rate must include non-depreciable plant in order to be revenue neutral.

6. ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

RUCO's pre-hearing revised ADIT adjustment calculates the ADIT balances based on the Company's proposed methodology for both the consolidated BVWC and the stand-alone Bella Vista, Northern and Southern systems There is an approximate $1,000 variation in amounts specified in final schedules for ADIT on a consolidated basis. RUCO's adjustment reduces the Company's consolidated Bella Vista $173,329 ADIT asset balance by $744,662 to $571,333. The Company' computes ADIT on a consolidated basis as $572,006. The differences are not substantial.

On an individual stand-alone basis, RUCO's revised adjustments reduces the Company's ADIT asset balance of the Bella Vista by $557,433, and increases the ADIT liability balances of the Northern and Southern systems by $57,846 and $93,375, respectively. The adjustments are as follows:

Company	RUCO ADIT Adjustments
Bella Vista	($ 557,433)
Northern	($ 57,846)
Southern	($ 93,375)[1]

7. SECURITY DEPOSITS

RUCO and the Company agree on the appropriate level of customer meter deposits and RUCO does not include customer security deposits in its calculation.

[1] The three systems on a stand-alone basis do not reconcile to the consolidated BVWC ADIT adjustment because the three systems have different effective income tax rates on a stand-alone basis.

8. "COMPETITIVE BIDDING" REQUIREMENT FOR "OUTSIDE SERVICES" EXPENSE.

Staff initially asserted that the Company must demonstrate that the affiliate billings in the outside services account had to be competitively bid to ensure the costs were equal to market rates. Staff subsequently abandoned the adjustment. Although the issue is now moot, RUCO agrees with Staff's underlying premise that affiliates which bill expenses to the Company must charge the lower of cost or market rate in compliance with NARUC.

9. RATE DESIGN STAND-ALONE BASIS-REVENUE SHIFTING

RUCO's stand-alone rate design allocates required revenue between residential, commercial and industrial ratepayers in the same percentages as the Company. However, RUCO's rate design reflects RUCO's recommended revenue requirements and provides proof that the design will produce the appropriate revenue requirements.

10. CONSOLIDATED RATE DESIGN

If the Commission determines that consolidation is in the best interest of the public, the parties agree to the consolidation of Bella Vista, Northern and Southern systems under BVWC. RUCO does not oppose the Company's proposed consolidated rate design, but offers alternatives as outlined in the testimony of RUCO's Executive Director, Jodi Jerich, which includes Option G which RUCO believes better balances the competing public policy concerns. As outlined in Ms. Jerich's testimony, Option G mitigates rate shock while also ensuring ratepayers in Northern and Southern systems do not garner an unearned benefit at the expense of Bella Vista's ratepayers.

B. UNRESOLVED ISSUES RELATED TO REQUIRED REVENUE

1. Central Office Cost Allocation

On a BVWC consolidated level, the Company sought to allocate $4.1 million in central office costs from the parent Algonquin Power Trust ("APT costs").[2] The Company argues that the APT costs were reasonable, but if the Commission disagrees, it should allow the allocations subject to a third-party attestation demonstrating the same.

RUCO and Staff believe that the APT costs were unreasonable, unnecessary to provide utility service, insufficiently documented and werenot useful or otherwise beneficial to Arizona ratepayers. RUCO also contends that the Company has not demonstrated that APT and its unregulated affiliates have charged expenses to its regulated affiliates in a manner consistent with NARUC guidelines. Staff agrees. Although RUCO and Staff object to the APT costs, both have provided alternative recommendations for inclusion of some expenses.

The issues identified by the parties are as follows:

a. Are the APT costs sufficiently documented and reasonable? If not, should the Commission approve the APT costs subject to the attestation of a third party?

b. Has the Company demonstrated that the APT costs are useful to the provision of utility service or otherwise beneficial to Arizona ratepayers?

c. Has the Company demonstrated that the affiliate costs included in the APT cost allocation were charged at the lower of cost or market?

d. Has the Company used an appropriate methodology to allocate costs?

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[2] The Company has also sought to allocate costs characterized as test-year direct cost in the amount of $1.3 million from Liberty Water to BVWC. Although both RUCO and Staff objected to the APT cost allocations, neither has a current objection to the Liberty Water cost allocations.

a. The APT costs are unreasonable and insufficiently documented and a third party attestation cannot remedy the deficiencies.

The APT costs have been the focus of dispute in every rate case filed by Liberty Water in the past two years. In each instance, Staff and/or RUCO objected to the APT costs arguing that the costs were unreasonable and insufficiently documented. In this case, the Company argues that the costs are only $1.09 per month per ratepayer and therefore reasonable. The Company requests that the Commission approve the APT cost allocations subject to an attestation of a third party CPA. The Company claims that all costs are indirect costs which should be shared by all subsidiaries.[3] RUCO adamantly disagrees. As RUCO witnesses, Mr. Coley and Ms. Jerich testified, the Company's proposal ignores the inadequacy of its invoices. CPA's Jeff Michlik, Sonn Rowell, and Gerald Becker have all audited the Company's APT invoices, looked at the supporting documentation and independently concluded the invoices are insufficient to determine whether the costs relate to direct costs which should be allocated to specific utility or whether they are indirect or common costs to be allocated to all affiliates.[4]

Likewise, in this case, both of the financial analysts for RUCO and Staff have concluded that the invoices are not adequately detailed to determine if the costs are direct or indirect costs. Because the Company generates revenues predominantly from its unregulated activities, both RUCO and Staff concur closer scrutiny is warranted. Id. They both concluded that allocating such costs would be unreasonable. Id. Mr. Coley testified that it would be

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3 T: 440-441.

4 See Exhibit R-13, Surrebuttal Testimony of Tim Coley incorporating by reference the previous testimony regarding APT cost allocations of CPA Jeffery Michlik in SW-01428A-09-0103; CPA Gerald W. Becker in WS-02676A-09-0257 and testimony of CPA Sonn Rowell and Analyst Matthew Rowell in SW-01428A-09-0103. See also Exhibit S-6, Direct Testimony of Crystal Brown at 31-34.

unreasonable to allocate the indirect costs which benefit unregulated entities to regulated utilities.[5]

Ms. Brown, Staff's witness, testified that:

> When costs incurred primarily for the benefit of an unregulated affiliate's business are improperly identified and allocated as overhead/common costs, then costs of the unregulated affiliate are shifted to the captive customers of the regulated utility. This cost shifting results in the captive customers of the regulated utility subsidizing the business operations of the unregulated affiliate. This harms customers by creating artificially higher rates. The costs of regulated utilities, such as the Algonquin Companies, should only include the lesser of actual costs or those costs that would have been incurred on a stand-alone basis.[6]

Although Staff and RUCO provide alternative resolutions to the problem of allocating unsupported APT costs, both agree the costs are insufficiently documented. Because the costs are not adequately documented, an allocation of $4.1 million in central office costs to BVWC is unreasonable. Moreover, the substitution of another CPA is not going to change the fact that the invoices are insufficient. The Company asks that the Commission defer to the decision of a CPA even after three other CPAs have already given their recommendatgions to the Commission. It is the Commission, not the Company or a third party CPA who has the right and obligation to determine the sufficiency of documentation and reasonableness of expenses and the rates which result. Accordingly, the Commission should reject the Company's request.

b. APT costs should be excluded because the Company has not demonstrated that they are necessary for the provision of utility service or beneficial to Arizona ratepayers.

RUCO and Staff both object to the APT costs because the Company has not demonstrated that the costs were necessary to the provision of utility service in Arizona or

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5 T: 712-717 and Exhibit S-6, Direct Testimony of Crystal Brown at 31-32.
6 See Exhibit S-6, Direct Testimony of Crystal Brown at 32.

otherwise beneficial to BVWC's ratepayers. Again, in prior Liberty Water cases, Mr. Michlik, Ms. Rowell and Mr. Becker all testified that the documentation of central office costs was insufficient to demonstrate that the APT costs related to the provisioning of utility service or are a benefit to Arizona ratepayers in those cases. Id. Both Mr. Coley and Ms. Brown reached the same conclusion in this case.

Mr. Coley testified that the NARUC Guidelines for Cost Allocations and Affiliate Transactions, states that, "The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities..."[7] The Guidelines also suggest that "to the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided." Id. Mr. Coley further testified that that the Company has failed to demonstrate how the APT costs contributed in any way, shape or manner to the improvement of BVWC or are beneficial to the Arizona ratepayers.[8] Based on the NARUC Guidelines, Mr. Coley excluded $3.68 million of the APT costs. Id. Ms. Brown testified that: "almost all of the costs were obviously attributable to the operations of the APIF or one of its affiliates." [9] Ms. Brown excluded $3.7 million of the APT costs. Id.

Because the Company has failed to demonstrate that the APT costs are useful to the provision of utility services in Arizona or that they are beneficial to ratepayers, the Commission should reject the allocations consistent with the analyses of RUCO or Staff.

c. APT costs should be excluded because the Company has not demonstrated that the billings from affiliates are the lesser of market or cost.

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[7] See Exhibit R-12, Direct Testimony of Tim Coley at 25-31 and NARUC Guidelines, attached thereto as RUCO Exhibit 4

[8] T: 712-717.

[9] See Exhibit S-6, Direct Testimony of Crystal Brown at 32-34.

RUCO also objects to the APT costs because they include multiple billings from affiliates. In order to include billings from affiliates, RUCO maintains that the Company must demonstrate that the expenses are the lesser of market or cost in compliance with applicable standards. RUCO asserts and the Staff concurs that affiliate transactions are subject to greater scrutiny. The Company must demonstrate as required by NARUC Guidelines, that the allocations of affiliate costs do not result in shifting of costs of the unregulated affiliates to captive ratepayers.

The Company admits that NARUC Guidelines regarding Cost Allocations and Affiliate Transactions generally require that the prices for services, products, and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated costs or prevailing market prices.[10] The Company has not demonstrated that the affiliate costs contained within the APT cost pool were incurred at the lesser of cost and market.

It is well understood that affiliated transactions are subject to greater scrutiny because they were not at arms length. The situation is even more suspect in this case because of the nature of the relationship between the entities in question. For example, the Company initially sought to allocate $307,000 for rent paid by APT to its landlord. The Company admits that the rental fees sought to be allocated by APT are amounts paid by APT to its landlord, Bristol Circle Partners. Id. The Company further admits that Bristol Circle Partners is an unregulated affiliate owned in part by Ian Robertson, Chris Jarratt and David Kerr, all of whom are former fund managers of Algonquin Power Income Fund("APIF"), the predecessor management company of APT and recipients of an $800,000+ management fee paid by APT and allocated

[10] T: 441-442. See also Exhibit R-20 NARUC Guidelines for Cost Allocations and Affiliate Transactions.

by ratepayers. Id. Mr. Jarrat and Mr. Robertson are also shareholders of Algonquin Power Utility Corporation, ("APUC"), the successor of APT and/or current or former officers or directors of APT.[11] Clearly, Bristol Circle Partners and its principals are affiliates of APT and its successor APUC.

Because of the affiliated nature of the companies and principals, RUCO issued data requests inquiring as to whether the amount APT seeks to allocate as rent would be less had APT sought a mortgage to construct or purchase the building. Because the best indicator of cost is the amount paid by Bristol Circle Partners or its predecessor to build or purchase the building, RUCO requested the cost information related to the construction or purchase of the building.[12] Although the Company provided documentation supporting its position that APT is paying its affiliates market rent, the Company objected and did not provide the cost information in response to a data request. Id. The Company claims that despite the fact that Jarrat, Robertson and Kerr office in the same building as Liberty Water, and are shareholders of its parent APUC, (the successor of APT), the Company is not able to acquire the information on the partners' costs to purchase or construct the building. Id. On cross exam, the Company admitted it had no information to determine whether the ratepayers' costs would have been less than the monthly rent paid Bristol Circle, the affiliate, if APT had bought or constructed the building directly.[13] Because the Company cannot demonstrate that the amount of rent APT pays to Bristol Circle Partners is less than the monthly payments to build or purchase the office building, the Company has not met the requirements of the NARUC standards and should be denied recovery of rental expense to its affiliate.

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[11] T: 441-460.

[12] Id. See also Exhibit R-19, Company's response to DR 4.01.

[13] T: 460.

d. The Commission should reject the Company's computation of APT costs and adopt RUCO or Staff's methodology.

On filing, the Company identified a total of $4.1 million in APT costs of which it initially allocated $144,906 to BVWC. RUCO believes that the Company's allocation is excessive. Mr. Coley testified, (as RUCO and/or Staff witnesses have in prior Liberty Water cases), that the better method would be to bill utilities for direct costs and allocate indirect costs on a revenue basis rather than treating each facility the same regardless of revenue or customer size.[14] RUCO submits that the Commission should consider the fairness of the Company's proposed allocation relative to an allocation based on revenue.[15]

In the test year, the revenue of all APT affiliates was $218,000,000.[16] In the same time period, BVWC claims total revenue of $4,023,022.[17] Dividing BVWC's total test-year book revenue by the total revenue of APT results in an allocation factor of 1.84 percent based on revenue.[18] In this case, the Company has adjusted the test year book value of its APT costs and seeks to allocate 3.52 percent of APT costs to BVWC.[19] The Company arrived at the 3.52 percent allocation factor by first allocating 26 percent of the adjusted $3.56 million cost pool to the regulated utilities operating under the auspices of Liberty Water. Then, the

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[14] T: 677-682. See also, Transcript of the proceedings *In the Matter of Litchfield Park,* SW-01428A-09-0103 et al. at 921-922.

[15] Id.

[16] See Exhibit R-1, Algonquin Power Annual Report for 2010. See also Quarterly Reports, Q2, Q3 and Q4 of Algonquin Power for 2008, attached hereto as Exhibit A.

[17] See A-7, Direct Testimony of Bourassa, Schedule C-1.

[18] The 1.84 percent factor is calculated as follows: $4,023,022/$218, 000,000 x 100=1.84 percent. RUCO is not arguing that the Commission should adopt a revenue based allocation factor of the entire cost pool in this case because it believes, (and Staff agrees), the APT costs are not properly documented, necessary to the provision of utility service or otherwise beneficial to Arizona ratepayers. However, RUCO provides this information to demonstrate the weaknesses in the Company's current methodology.

[19] See RUCO's Final Schedules, Schedule RLM-11B. Company's adjusted allocated BVWC Costs / Company adjusted APT Costs ($125,830/$3,567,363=3.53)

Company further allocated that amount between Liberty Water subsidiaries on a customer count basis arriving at a cost allocation of $125,830 which represents 3.52 percent of the adjusted APT cost pool. The Company's "unit/customer count" based methodology results in an over collection of 1.69 percent or nearly 100 percent more in APT cost recovery from BVWC.[20] Based on the foregoing, the Company's methodology seems patently unfair and unreasonable, particularly when one considers the absence of sufficient documentation to support the APT cost pool or evidence that the costs were necessary for the provision of utility service or otherwise beneficial to Arizona ratepayers.

In light of the foregoing, the Commission should reject the Company's allocation methodology and adopt one of the alternative methodologies offered by RUCO and Staff. RUCO used a methodology similar to that applied by the Commission in Black Mountain to arrive at a BVWC allocation of $15,352.[21] RUCO disallowed $3.68 million of the APT costs permitting allocation of limited expenses for tax, audit, depreciation and legal. Id. at line 13. However, due to the absence of adequate documentation, RUCO disallowed all but 25 percent of the tax, audit, depreciation and legal costs or $416,941.[22] Then, using the same methods adopted by the Commission in Black Mountain, RUCO divided the pool between regulated and unregulated utilities, allocating 25.35 percent[23] to regulated entities operating under the auspices of Liberty Water. Next, RUCO reallocated the amount among the Liberty Water utilities based on customer count which results in an allocation of $15,352 to BVWC on a

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[20] The difference between the Company's cost allocation factor and a revenue based factor is calculated as follows: 3.52-1.84= 1.69

[21] *In the Matter of Black Mountain*, Docket No. SW-023618-08-0609; *In the Matter of Litchfield Park*, SW-01428A-09-0103 et al.: and In *the Matter of Rio Rico*, Docket No.WS-02676A-09-0257.

[22] See RUCO Final Schedules SURR RLM-11A.

[23] According to Exhibit R-1 Algonquin Power's 2010 annual report, APT now has 19 water facilities, 45 renewable energy facilities and 14 thermal energy facilities. Arguably, using the current information, the Company's allocation factor should now be 19/78 x 100 or 24.35 percent.

consolidated basis.[24] On an individual stand-alone basis, RUCO's initial adjustments to the APT cost allocations on a customer count basis were as follows:

Company	RUCO APT Adjustments
Bella Vista	$ 122,927
Northern	$ 5,088
Southern	$ 12,118

The Staff made similar reductions using a different methodology. The Staff disallowed $3.7 million of the APT costs and allocated 1.42 percent (1/70) of the total remaining APT costs or $3,132 to each of the BVWC utilities on a stand-alone basis and $9,396 of the APT costs on a consolidated basis.[25]

Relief Requested: The Commission should deny the Company's request for an APT cost allocation. If the Commission determines that some portion of the APT costs should be allocated, the Commission should do so using the Staff's recommendation of $9,396 or RUCO's recommendation of $15,352.[26]

2. Rate Case Expense

The Company seeks $450,000 in rate case expense. Normalized over three years, the Company's initial request is $150,000 per year. RUCO recommended a total of $200,000 (normalized over three years) or $66,000 per year. Staff recommends a total of $151,530 amortized over three years or $50,510 per year. In evaluating this issue, the Commission needs to decide:

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[24] See RUCO Final Schedules SURR RLM-11A

[25] See Exhibit S-6 at 33-36.

[26] RUCO made two additional adjustments: Adjustment 6(b) a reduction of $1.093 and Adjustment 6(c) a reduction of $11,243. Both reductions result from the Company's admission that APT costs included in the Outside Services-Other account were overstated. If the Commission concurs, then RUCO's APT cost recommendation would be reduced to $3,016.

a. Has the Company demonstrated that its request for rate case expense is sufficiently documented, reasonable and necessary for the provision of utility service?

b. If the rate case expense is equally beneficial to shareholders, should the shareholders also bear some of the expense of reasonable rate case expense?

a. The Company request for rate case expense is not adequately supported, reasonable or necessary for the provision of utility service.

The Company has the burden of supporting its request for rate case expense. The Company must demonstrate that the expenses are reasonable and necessary to provide utility service. It didn't. For that reason alone, the Company's request for rate case expense should be denied.

RUCO requested documentation supporting the Company's request for rate case expense. The Company objected and provided nothing more than $59,206 of actual expenses incurred through February, 2010 and an estimate of $450,000 unsupported by sufficient documentation or detail.[27] Because the Company's estimate of future rate case expense was excessive and unsupported, RUCO calculated its own estimate of what the Company's remaining future rate case expense should be. As Rodney Moore, RUCO's witness testified, RUCO based its estimate of future rate case expense on the Company's estimate of rate case expense in the Black Mountain as shown below:[28]

27 See Final Schedule RLM-12 at line 7-8.
28 See RUCO's Final Schedule RLM-12.

RUCO's Estimate of Future Rate Case Expense from Rebuttal-End Using Company's Black Mountain Estimate

Billing Segments Rebuttal-End	Company's Estimate BMSC	RUCO's Estimate In BVWC
Additional fees for Thomas Bourassa:		
(Rebuttal, Surrebuttal, Rejoinder and Trial Process; Final Schedules, Assistance with Briefing; Evaluation of ROO; Open Meeting Prep)	$25,000	25,000
Expedited Hearing Transcript	$5,000	5,000
Additional Fees for Fennemore Craig		
Surrebuttal Review-End of Trial	$35,000-$45,000	45,000[29]
Briefing	$25,000-$30,000	30,000
Review ROO; Exceptions Open Meeting Prep.	$10,000	10,000
Post Decision Compliance and Filings	$10,000-$15,000	15,000
RUCO's Additions for BVWC		
Per Diem for Tucson Travel		10,000[30]
Rounding		794[31]
Estimated Future Rate Case Expense from March, 2010-end of case:		$140,794
Actual Invoices Beginning-February, 2010:		59,206
RUCO's Total Estimate of Rate Case Expense:		$200,000

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29 Id. Note: RUCO used the Company's highest estimate of future rate case expense in Black Mountain to establish its estimate of future rate case expense in BVWC.

30 The Company's estimate for Black Mountain did not include travel per diem. RUCO's estimate did because the hearing in BVWC was originally scheduled for Tucson, Arizona.

31 RUCO rounded the Company's actual expense through February, 2010 from $59,206 to up to $60,000.

The Company's estimate in Black Mountain provides a reasonable basis for computing Bella Vista's rate case expense from March, 2010 through case completion because it involves the same billing segments for the Company: Rebuttal – end of case. The Company complains that the Black Mountain case is not a comparable basis for analysis because the case did not involve the issue of rate consolidation. While it is true that the Black Mountain case did not involve a rate consolidation issue, it did involve multiple intervenors, not present in this case, and the complicated issue of infrastructure surcharges and approval of an agreement with a homeowner association to close the entire plant.

The Company is correct that as filed, rate consolidation was an issue in dispute in BVWC. However, the Company is not correct that the inclusion of the issue in BVWC should result in additional rate case expense than it estimated in Black Mountain. Since RUCO and Staff filed their direct testimony, rate consolidation has not been a disputed issue. All parties in BVWC agreed to rate consolidation, if the Commission determined that it was in the public's interest. The last testimony developed and filed by the Company related to rate consolidation was filed on application in October, 2009. The Company's rate case expense associated with rate consolidation is included in the actual rate case expense of $59,206, which covers the time period from filing through February, 2010. From that point on, this case was just a "typical rate case" as even the Company admits.[32] Accordingly, the issue of rate consolidation in this case is not a reason to ignore the Company's Black Mountain estimate of reasonable future rate case expense from Rebuttal through the close of the case and the Company's estimate in Black Mountain is entirely relevant. It may not result in the excessive fees the Company seeks, but it is equally applicable in this case.

At hearing, RUCO agreed to review the Company's actual invoices and provide a final recommended level of rate case expense when it filed its final schedules after the evidentiary

[32] T: 11

hearing on the instant case concluded. RUCO has reviewed the Company's actual invoices, but sees no reason to modify its recommendation of $200,000 in rate case expense. First, RUCO's estimate included travel expense of $10,000 calculated at $1,000/day for 10 days associated with holding the case in Tucson. Because the case was rescheduled in Phoenix, the Company did incur the travel expense in August resulting in an estimated savings of $8,000. Further, because of the lengthy briefing schedule, there was no need for an expedited transcript resulting in additional savings. Because the Company experienced unanticipated rate case expense savings, RUCO did not increase its recommended rate case expense.

To determine the reasonableness of the Company's rate case expense, Staff witness, Crystal Brown, compared the Company's rate case expense request of $450,000 to the requests from Arizona-American Water Company, Arizona Water Company, and Global Water Company.[33] On average, Ms. Brown testified that the requested rate case expense of Arizona-American, Arizona and Global was $61,200, $29,412 and $19,054 per system, respectively or an average of $37,883. Id. Ms. Brown then applied the average allowing BVWC to recover $37,883 for each system and an additional $37,883 for the consolidation case for a total of $151,232. Id. Based on her comparative data, Ms. Brown concluded, as did RUCO, that the Company's request for $112,500 per system was unreasonable. Id. Ms. Brown further testified, and RUCO agrees, that the Company's excessive request results from its failure to control costs. Unlike Arizona-American, Arizona Water or Global, the Company's request for $450,000 reflects a failure to utilize internal resources to minimize rate case expense. Id. As a result, its estimated rate case expense is excessive.

Relief Requested: Based on the testimony of Mr. Coley and Ms. Brown, RUCO requests that the Commission deny the Company's request for $450,000 in rate case expense as unreasonable and unnecessary for the provision of utility services. Instead, RUCO

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[33] See S-6 Direct Testimony of Crystal Brown at 41-42.

requests that the Commission adopt its recommendation of $200,000 in rate case expense normalized over three years for a total of $66,000[34] or Staff's recommendation of $151,530 in rate case expense, normalized over three years for a total of $50,510.[35]

b. Shareholders benefit equally from the expenditure of rate case expense and should contribute toward the reasonable rate case expenses.

A rate case is the means by which the Commission establishes reasonable rates for ratepayers. However, a rate case also establishes the required revenue requirement and return on investment for shareholders. Because shareholders receive a benefit from rate cases, the Commission should examine whether shareholders should bear an equal measure of reasonable rate case expense.

The Company asserts that it will pay the rate case expense in excess of the approved rate case expense and therefore it is sharing in rate case expense. The Company's argument is shallow because the Company's request is clearly excessive. Moreover, rate case expenses in excess of what is reasonable are "unreasonable." Shareholders should bear the cost of excessive expenses as a consequence of a failing to control internal resources.

Since shareholders derive at least equal benefit from rate case expense, the Commission should require shareholders to bear an equal portion of rate case expense. Further, the Commission should require shareholders to pay for ecessive rate case expenses. To do otherwise, would reward the shareholders for failing to control rate case expenses.

Relief Requested: Allocate 50 percent of rate case expense to shareholders as equal beneficiaries of the rate case, reducing the rate case expense from $200,000 normalized over three years to $100,000 in rate case expense normalized over three years or $33,000 per year.

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34 See RUCO's Final Schedule RLM-12

35 See S-6 Direct Testimony of Crystal Brown at 41-42

C. UNRESOLVED ISSUES RELATED TO COST OF CAPITAL

1. Return on Equity

The parties disagree on the cost of equity and the overall weighted average cost of capital. The Company recommends a cost of equity of 10.5 percent.[36] Staff recommends a cost of equity of 9.3. Id. the RUCO recommends a cost of equity of 9.00 percent, which results in a fair and reasonable recommended rate of return. Id.

RUCO performed both a Discounted Cash Flow ("DCF") analysis and a Capital Asset Pricing Model ("CAPM") analysis. RUCO's cost of equity of 9.0 percent is at the high end of the ranges of its DCF and CAPM analysis.[37] RUCO utilized samples of both publicly traded water providers and a sample of publicly traded natural gas LDC (local distribution companies) to arrive at its cost of equity.[38] RUCO submits that the use of gas LDCs is an entirely acceptable methodology. In computing the CAPM, RUCO used both geometric and arithmetic means, a methodology approved by the Commission in several cases.[39]

RUCO opposes the cost of equity sponsored by the Company in part, because it is based upon a CAPM analysis which relied on a high market risk premium, ignored widely used geometric means of market returns and used a long-term treasury instrument which resulted in yields which overstate the cost of equity capital. Id. at 21. RUCO used five-year treasury instrument to estimate a market risk premium, which is more reflective of the period in which utilities typically apply for rate relief. In addition, RUCO opposes the Company's attempt to apply a small company risk premia which is unreasonable given that BVWC receives virtually all of its capital from its parent, APT, which does not suffer any of the small firm risks that the

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36 See Exhibit R-8 Rigsby's Surrebuttal Testimony at 5-7.
37 See Exhibit R-6, Rigsby's Direct Testimony at 35.
38 Id. at 8-9. See also R-8 Rigsby's Surrebuttal at 12-14.
39 See R-8 Rigsby's Surrebuttal at 15-20.

Company's witness analyzes in his determination of an upward adjustment of 50 basis points.[40] For these reasons and those more fully developed in testimony, on a consolidated basis, RUCO recommends adoption of its cost of common equity of 9.0 percent and its weighted cost of capital of 8.42 percent.

a. RUCO'S use of a historic market risk premium to determine its CAPM cost of equity capital was appropriate.

In calculating a cost of equity, both the Company and RUCO used the Capital Asset Pricing Model ("CAPM"). The CAPM is a mathematical tool developed during the early 1960's by William F. Sharpe, the Timken professor Emeritus of Finance at Stanford University.[41] CAPM is used to analyze the relationships between rates of return on various assets and the risk as measured by beta.[42] The underlying theory behind the CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic, non-diversifiable risk, associated with that investment.[43]

On Direct Testimony, the Company arrived at its CAPM cost of equity capital of 12.5 percent based on analysis of historical and current forecasted market risk premium and exercise of judgment. In his CAPM analysis, Mr. Bourassa used a historical market risk premium which produced a result of 10.1 percent and a 21.0 percent CAPM derived from a current forecasted market risk premium.[44] RUCO derived its CAPM cost of equity capital based on a historic market risk premium.[45] RUCO calculated a range for its CAPM cost of

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[40] See R-6 Rigsby's Direct at 63.

[41] See Exhibit R-6, Rigsby Direct Testimony at 29.

[42] Beta is defined as an index of volatility or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

[43] See Exhibit R-6 at 30.

[44] Id. at 57.

[45] See Exhibit R-6 Rigsby's Direct Testimony at 61-62.

equity capital between 5.44 percent-6.83 percent for its water sample and 5.13 percent-6.39 percent for its natural gas proxy.[46]

The Company claims that RUCO's CAPM analysis is not reliable because it is based on a historic market risk premium. William Rigsby, RUCO's expert witness, testified that use of a historic market risk premium to derive a CAPM cost of equity capital is an accepted methodology utilized by Staff witnesses in the past and adopted by the Commission in a recent UNS Gas case.[47] Reliance on past performance as an indicator of future performance is sounder than reliance on analysts' projections of market return and treasury yields. RUCO recommends the Commission adopt RUCO's cost of equity capital, which incorporates the CAPM, but is weighted to the high end of its DCF analysis.

b. RUCO'S use of a geometric mean to determine its historic market risk premium in the CAPM is appropriate.

The Company claims that RUCO's historic market risk premium is also unreliable because it is based in part on a geometric mean. The Company claims that RUCO's historic market risk premium should be based solely upon an arithmetic mean. RUCO's historic market premium was derived from both a geometric and an arithmetic mean of the historical returns on the Standard and Poor 500 ("S&P 500") index from 1926 to 2008 as the proxy for the market rate of return. Id. To calculate its market risk premium, RUCO used the geometric and

arithmetic means of the yields of long-term government bonds for the same eighty-two year period resulting in a historic risk premium of 4.20 percent using a geometric mean and a historic risk premium of 6.10 percent using an arithmetic mean. Id.

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[46] Id. at 35.
[47] See Exhibit R-8 Rigsby's Surrebuttal at 15-26.

The use of geometric mean is the industry standard. Id. at 16. Mr. Rigsby testified that geometric means are published in Morningstar stocks, bonds, bills and inflation text and testified that analysts rely on geometric means to calculate a market risk premium. Id. Mr. Rigsby further testified that Value Line analysts use geometric means. Id. He also testified that use of a geometric and arithmetic means has been supported by Staff's witnesses. Id. at 18. In UNS Gas, David Parcell, Staff's witnesses utilized both geometric and arithmetic means in his testimony and said that he did so routinely. Id.

In his testimony, Mr. Rigsby also cited to the text: <u>Valuation: Measuring and Managing the Value of Companies</u>, 3rd Edition, which states that although an arithmetic mean may be regarded as being more forward-looking, a true market risk premium may lie somewhere between the arithmetic and geometric averages and concluded that 4.5-5.5 percent is a reasonable forward-looking market risk premium. Id. at 19. Adding RUCO's 2.36 percent risk free yield on a 5-year treasury instrument to the 4.5 and 5.5 percent market risk premium suggested by the text, indicates a cost of equity of 6.86 percent and 7.86 percent, respectively. Id at 20, 24-25. RUCO has recommended a 9.0 percent cost of equity which is above the cost of equity which would be derived using the range of market risk premium recommended by the treatise. RUCO's analysis is more favorable to the Company and is reasonable.

c. A proxy of publically traded gas companies is acceptable for the purposes of calculating the cost of capital.

The Company contends that RUCO erred in using a proxy of gas utilities ("LDCs") to derive its cost of capital.[48] The Company contends that gas companies are less risky investments than water companies and should not be used as proxies for the Company. Id.

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[48] See Exhibit A-17, Bourassa's Rejoinder Testimony at 27-29.

Mr. Rigsby testified the use of an LDC proxy to derive the cost of equity in a water utility is accepted methodology.[49] He identified both Staff and Company witnesses, Villadsen and Parcell who both use or support the used of LDC proxies in water utility cases.[50] Moreover, Mr. Rigsby testified that the issue of RUCO's LDC proxy is irrelevant because RUCO[s 9.0 percent cost of equity was based on the high end of the range of his CAPM and DCF analysis which was derived from his analysis of water utilities.[51] Because RUCO's 9.0 percent cost of equity is much higher than the expected returns produced by the CAPM model using LDC, the Company's concerns regarding the use of an LDC proxy is without merit.

d. RUCO'S 9.0 percent cost of equity capital is not too low.

The Company asserts that RUCO's cost of common equity of 9.0 percent is too low because common shareholders bear a greater risk than bondholders and expect a higher return than the risk of a utility debt instrument. The question of what level of additional market risk premium is necessary to derive a higher return is a moot issue. RUCO's cost of equity capital is 324 basis points higher than the 5.76 percent yield on Baa/BBB rated utility bonds and 374 basis points higher than the recent 5.26 percent yield on A-rated utility bonds. RUCO's cost of equity capital includes a sufficient margin to satisfy common shareholders for any perceived additional market risk.[52]

Relief Requested: Based on the foregoing, RUCO requests that the Commission deny the Company its requested 10.5 percent cost of equity and its weighted average cost of capital of 9.85 because the Company's request is simply too high.[53] Second, if the Commission denies the Company's request for rate consolidation, RUCO requests that the Commission

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[49] T: 320
[50] T: 320-322.
[51] Id. at 321. See also, Schedule WAR-1, page 3 of 3.

[52] T: 325-327. See also Exhibit R-16 Value Line Selection and Opinion publication, dated July 16, 2010
[53] See Exhibit R-8 Rigsby's Surrebuttal at 5-6.

approve its cost of equity of 9.0 percent and its weighted average cost of capital of 8.42 percent. Id.

D. UNRESOLVED ISSUES RELATED TO COST OF CAPITAL ON A STAND ALONE BASIS

1. Hypothetical Capital Structure of Northern and Southern on a Stand-Alone Basis

On a stand-alone basis, there are additional disputes as to the capital structure and hypothetical debt of the Northern and the Southern systems. The Company proposes use of a 100 percent equity structure for the Northern and the Southern systems on a stand-alone basis. RUCO recommends a hypothetical capital structure of 40/60 debt/equity for Northern and Southern Sunrise on a stand-alone basis. If the Commission grants rate consolidation, the issue of a hypothetical capital structure and hypothetical debt of the stand-alone systems will be moot. In the event that the Commission rejects the notion of a consolidated rate design, RUCO requests that the Commission adopt a hypothetical capital structure for Northern and Southern Sunrise.[54] On a stand-alone basis, Northern and Southern Sunrise have 100 percent equity structures. Mr. Rigsby testified that use of a hypothetical capital structure is appropriate to adjust for the absence of financial risk associated with the 100 percent equity structure of Northern and Southern Sunrise on a stand- alone basis. RUCO's use of a hypothetical capital structure is supported by the Commission's recent decision issued _In the Matter of Gold Canyon_.[55] Gold Canyon is another Liberty Water utility which has a 100 percent equity structure. Id. In the _Gold Canyon_ decision, Decision No. 70624, the Commission determined that a 100 percent equity structure is imprudent and adopted RUCO's hypothetical capital structure consisting of 40 percent debt and 60 percent equity as a means to adjust for the

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[54] See Exhibit R-6, Direct Testimony of William A. Rigsby at 54-56.

[55] _In the Matter of Gold Canyon_, Docket No. SW02519A-06-0015, Decision No. 70624. See also Exhibit R-7 Supplemental Direct Testimony of William A. Rigsby at 7-9 and R-8 Rebuttal Testimony of William A. Rigsby at 11.

absence of financial risk in the utility's capital structure. Id. Although the decision was appealed, has not been overturned.

Relief Requested: On appeal, the Court of Appeals affirmed the Commision's decision. If the Commission denies the Company's request for rate consolidation, the Commission should follow the methodology adopted in Decision No. 70624 and approve RUCO's use of a hypothetical 40/60 debt/equity structure for Northern and Southern Sunrise on a stand-alone basis.[56]

2. Cost of Hypothetical Debt for Northern and Southern Sunrise

Because RUCO uses a hypothetical capital structure for Northern and Southern Sunrise on a stand-alone basis, it must also derive a hypothetical cost of debt. On a stand-alone basis, RUCO recommends a hypothetical cost of debt of 6.26 percent for the Northern and Southern Sunrise Systems.[57] The Company argues that RUCO's recommended hypothetical cost of debt for Northern and Southern Sunrise is too low, and does not reflect the realities of operating the two small water utilities operating under the shadow of the former McLain systems. First, the McLain systems initially procured debt at the rate of 6.27 percent.[58] There is no reason to believe that in this time of historically low cost debt financing, the Company now owned by Algonquin and operated by Liberty Water could not procure debt financing at the same or lower rate as the McLain systems with its notoriously poor operating history. Second, RUCO's 6.26 percent hypothetical cost of debt for the Northern and Southern systems is 1 basis point lower that the 6.27 percent cost of debt adopted by the Company for BVWC on a consolidated basis.[59] Moreover, RUCO's hypothetical cost of debt is 50 basis

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[56] *In the Matter of Gold Canyon*, Docket No. SW02519A-06-0015, Decision No. 70624. See also Exhibit R-7, Supplemental Direct Testimony of William A. Rigsby at 7-9 and R-8 Rebuttal Testimony of William A. Rigsby at 11.

[57] Supplemental Direct Testimony of William A. Rigsby at 9-13.

[58] T: 325, 345.

[59] See Exhibit R-7 Rigsby's Supplemental Direct Testimony at 3.

points higher than the 5.76 yields on Baa/BBB rated utility bonds published by Value Line on July 16, 2010.[60]

Relief Requested: If the Commission denies the Company's request for rate consolidation, RUCO requests the Commission adopt RUCO's hypothetical cost of debt for the Northern and Southern Sunrise systems following the methodology adopted in Decision No. 70624 and approve RUCO's recommended hypothetical cost of debt of 6.27 percent.

E. RATE DESIGN

1. RUCO's consolidated rate design

RUCO submits that as a general rule, cost of service rate design is the cornerstone to sound ratemaking. However, based on the individual facts and circumstances of this case, RUCO has not objected to the Company's proposal to a consolidated rate design for the Bella Vista, Northern Sunrise and Southern Sunrise water systems. Staff concurs.

Although there is no substantive disagreement between the parties regarding the issue of consolidation, several points raised in the testimony of RUCO's Executive Director, Jodi Jerich deserve emphasis and may help guide the Commission in deciding the issue. As Ms. Jerich testified, the Commission could find that the policies in favor of rate consolidation outweigh those policies against rate consolidation as applied to the specific facts of this case.

Ms. Jerich testified RUCO does not object to rate consolidation of the BVWC systems because of the following unique facts:

1. All three systems have similar water consumption patterns so a consolidated rate design would not distort price signals and contradict the Commission's important goal of water conservation.

2. The three systems draw from the same water source.

3. Two of the three systems (Bella Vista and Southern Sunrise) are physically interconnected and the third system (Northern Sunrise) is only six miles from Bella Vista. Liberty is in essence a "regional" water provider.

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60 T: 326. See also R-16 Value Line Report on Selected Yields dated July 16, 2010.

4. The utility has a history of acquisition of small water utilities and rate consolidation. In 1999, it acquired Nicksville Water and consolidated its rates with Bella Vista (Decision No. 61730). In 2006, the utility acquired the McLain water systems and consolidated its seven systems into the Northern and Southern Sunrise systems (Decision No. 68826).

In addition, Ms. Jerich testified that there are several benefits of approving a consolidated rate design in this case. First, a consolidated rate design would mitigate rate shock for the customers of the very small Northern and Southern Sunrise systems while shifting only a small amount of costs on to the Bella Vista customers. Second, by spreading costs over a larger customer base, a consolidated rate design would reduce the severity of rate increases for all customers in future rate cases.

Ms. Jerich also testified that a consolidated rate design would essentially create a "regional water company" as also described in Mr. Sorenson's direct testimony. By consolidating the systems, the Company may be better able to meet the needs of the very small Sunrise systems with a larger cushion of cash. Moreover, the revenue sharing of a consolidated rate design would allow the Company the operating income from all three systems to meet the needs of the systems on a "regional" basis. Without rate consolidation, Liberty would be limited to making improvements to each system from the individual operating incomes from that specific system.

The Commission's approval of a consolidated rate design might also benefit the Commission's regulation of other small systems, namely, East Slope Water, Antelope Run and Indiada. Each of the systems has either pending or recently resolved Notices of Violation ("NOVs") and are located near the Liberty systems. Ms. Jerich testified that allowing consolidation may put the Company in a position to consider acquiring other small and struggling water systems that are providing service in the area.

RUCO recommends two alternative models of consolidated rate design. Under RUCO's first rate consolidation proposal, Option F, the average residential Bella Vista customer would incur an increase of $2.70 and bear some of the costs of the other two systems based on RUCO's required revenue requirement in surrebuttal. As Ms. Jerich testified that Bella Vista customers would receive the benefit of having a portion of their costs paid by the other systems in future rate cases, but in this case, they will pay more so that the customers of Northern and Southern Sunrise can pay less. In the event that the Commission wished to reduce Bella Vista's subsidy of the Northern and Southern Sunrise systems, RUCO offered its second alternative, Option G. RUCO's Option G mitigates the revenue shift to Bella Vista and avoids an unearned decrease in the Northern and Southern systems. Under Option G, all systems would have the same basic rates, but Northern and Southern Sunrise ratepayers would pay a surcharge bringing their rates up to a level equal to their current rates and the average Bella Vista customer would pay $0.35 increase (after all credits) instead of the $2.70 subsidy under Option F.

Relief Requested: If the Commission believes the policies in favor of rate consolidation outweigh those policies against rate consolidation as applied to the specific facts of this case and concludes that rate consolidation is in the public interest based on the unique facts of this case, RUCO does not object.

2. Hook-Up Fee Tariff

The Company proposes language in its HUF tariff providing that HUF funds received will <u>not</u> be recorded as Contributions In Aid of Construction ("CIAC") until they are spent.. RUCO is adamantly opposed to the proposed language. RUCO believes that HUF proceeds are CIAC and as such must be recorded on receipt in compliance with existing rules, NARUC standards and the precedence established by the prior rulings of the Commission.[61] Moreover,

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[61] See Exhibit R-24 *In the matter of Johnson Utilities*, Decision No. 60223 dated May 27, 1997. *In the Matter of UNS Electric*, Decision No. 70011.

delaying the recording of CIAC until the Company spends the funds ultimately will result in Staff having to "chase the CIAC' to make sure it is properly recorded once plant is in service.[62]

a. HUF Payments are CIAC and are a reduction to rate base under NARUC, the Commission's rules and prior decisions.

Mr. Sorenson asserts that the Company's HUF proposal is entirely consistent with NARUC, which defines CIAC as something given to the utility to "offset" the cost of plant, and the language avoids unintended reductions in rate base for amounts of money of which the Company has no beneficial use. Although Mr. Sorenson claimed the funds would be segregated and restricted, for accounting purposes, it does not appear that the funds are going to be restricted in a third party account and held in trust.[63] He asserted that the Company would "segregate" the HUF funds by establishing a deferral account entry allocating the HUF funds for a specified purpose.[64]

RUCO and Staff oppose the HUF tariff proposal because it does not require HUF funds be recorded as CIAC upon receipt consistent with the recent decisions of the Commission and with NARUC USOA. Moreover, according to the testimony of Mr. Sorenson, the Company will have beneficial use of the HUF funds. Payments received pursuant to a HUF tariff are cash and cash is fungible. The accounting entry in a deferral account does not limit the Company's beneficial use of funds in its account. Accordingly, RUCO believes that the portion of the Company's HUF tariff which allows recording of the amounts as CIAC only upon completion of plant should be disallowed.

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62 T: 754-758.
63 T: 114-115.
64 T: 109-114

Further, RUCO believes that the proposed tariff also violates the requirements of the The Uniform System of Accounts for Class A Water Utilities. The relevant provision states:

> 271. Contributions in Aid of Construction
>
> A. This account shall include:
>
> 1. Any amount or item of money, services or property received by a utility, from any person or governmental agency, any portion of which is provided at no cost to the utility, which represents an addition or transfer to the capital of the utility, and which is utilized to offset the acquisition, improvement or construction costs of the utility's property, facilities, or equipment used to provide utility services to the public.

The Company asserts that this section supports its proposal to avoid recording amounts collected under this tariff "as CIAC until such amounts have been expended for plant." RUCO's interpretation of section 271 is that CIAC should be recorded immediately upon receipt regardless of when it is expended. Staff concurs. Staff witness, Crystal Brown testified that the Company's interpretation was inconsistent with the recommendations of the NARUC Staff Subcommittee on Accounting and Finance as set forth in the Rate Case and Audit Manual.[65] She testified that the Subcommittee defines CIAC and Customer Advances as "payments made by customer generally to fund plant additions for new and expanded service." Ms. Brown further testified that the Subcommittee stated that CIAC and Customer Advances are a reduction to rate base because they are a source of non-investor supplied capital.[66] The Company asserts that HUF proceeds are not necessarily CIAC. Although RUCO's witness, Mr. Coley, acknowledged that in the distant past the Commission treated payments received from developers as revenue, but that for some time, the Commission has treated HUF

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[65] T: 751 See also S-13 NARUC Staff Subcommittee on Accounting and Finance.
[66] Id. See Also T: 751-752.

proceeds as CIAC and deducted those amounts from rate base upon receipt.[67] In response to the Company's position, Staff witness, Ms. Brown response was unwavering: the Administrative Code requires a company to keep it books and records in accordance with the NARUC Uniform System of Accounts and NARUC requires that monies and cash received are CIAC and that CIAC shall be a reduction to rate base.[68]

b. The Company's proposal will result in a poor public policy necessitating Staff to "chase the CIAC."

RUCO believes that denial of the HUF tariff language as proposed by the Company will result in no harm to the Company, and will avoid potential harm to ratepayers and a significant burden on Staff to "chase the CIAC." Historic accounting methodology approved by the Commission and dictated by NARUC requires that the Company record CIAC upon receipt and reduces rate base even without a corresponding entry in the "plant in service" ("PIS") account. While this does reduce rate base at first, it is definitely not a "penalty" as claimed by the Company. The Company is ultimately made whole. Once the Company decides to use the CIAC funds, it places the value of the plant acquired in its PIS account. Once the CIAC is fully amortized, the PIS still has value and rate base will be higher than if CIAC and PIS were recorded simultaneously. It is simply a matter of timing. Any reduction in rate base experienced up front is recovered on the back end.

However, approval of the Company's HUF tariff as written will result in an incredible burden on Staff, potential harm to ratepayers and an avenue for either outright fraud or innocent neglect. As Staff witness, Ms. Brown testified, the Company's proposal creates a

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[67] See Exhibit R-24 _In the Matter of Johnson Utilities_, Decision No. 60223 dated May 27, 1997. _In the matter of UNS Electric_, Decision No. 70011.
[68] T: 753-754.

definite problem for Staff, RUCO or even the Company to follow or "chase CIAC." [69] Ms. Brown testified if there was a turnover in the personnel of the Company or Staff, plant could be added without a corresponding entry in the CIAC account causing ratepayers to pay more money in rates because of the Company's failure to include the offsetting deduction or reduction to rate base. Id. Moreover, if Staff is unable to successfully chase or follow the unrecorded CIAC, the Company would end up with the unjust benefit of earning a return on the assets that were paid for by others and ratepayers would essentially pay twice: once through CIAC and again through rates. Id.

Although Staff did not testify to the possibility of fraud, the fact is that the Company's HUF proposal does provide an avenue for a utility to use the all too common turnover in personnel at RUCO and Staff to perpetuate a fraud. Although utilities have every motivation to record plant, there is no corresponding incentive to record CIAC. At that point, which may be years after the CIAC is received, it is up to Staff to remember that certain additions to PIS came from non-investor supplied funds. Hence, Staff must "chase" the CIAC. With Staff turnover, it may be difficult, if not impossible, for Staff to keep track of unrecorded CIAC funds. The same holds true for the Company. Even if the Company has every intention of recording CIAC and PIS at the same time, employee turnover may make it difficult for the Company to remember which non-investor supplied funds paid for what plant.

Relief Requested: Because the Company is made whole and there is no need to adopt the Company's HUF tariff language which would puts the Staff in the position of having to chase unrecorded CIAC. RUCO agrees with Staff and recommends that the hook-up fee

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69 T: 757-758.

tariff language permitting CIAC to be recorded when expensed be denied. A hook-up tariff should be permitted, but the Commission should require that CIAC be recorded upon receipt.

RESPECTFULLY SUBMITTED this 5th day of October, 2010.

Michelle L. Wood
Counsel

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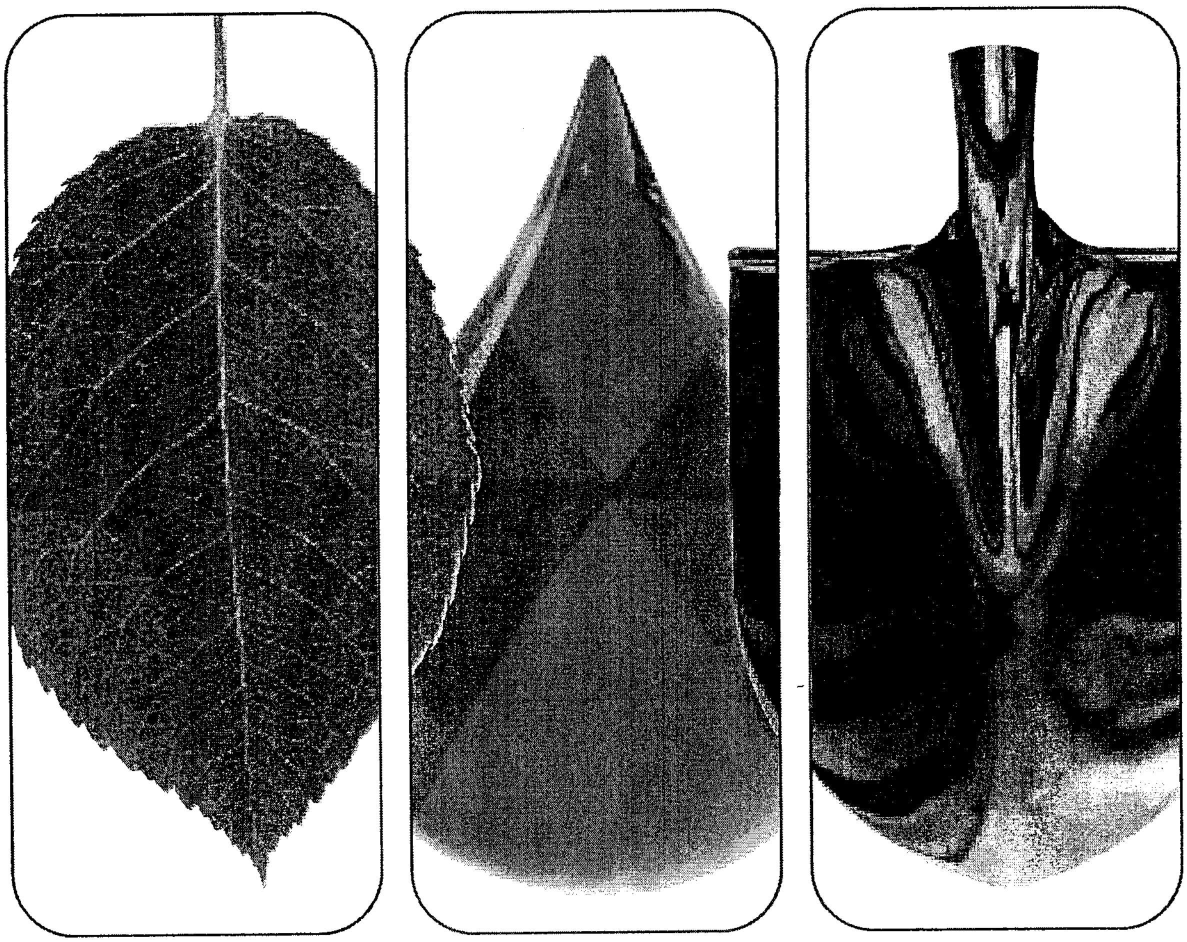
EXHIBIT A

Second Quarter Report

June 30, 2008



ALGONQUIN POWER

Report to Unitholders

Business Review

As reported in the last letter to unitholders, in January 2008 Algonquin Power realigned its operations into two major business units: Power Generation & Development, and Utility Services. The Power Generation & Development business unit has three distinct divisions: Renewable Energy, Thermal Energy and Development. The Utility Services business unit consists of a Water and Wastewater division. The re-alignment was completed in order to more effectively position Algonquin Power to compete in the clean, renewable energy and utility services business sectors. To date, the Company has successfully moved into the new internal structure and is focused on effectively managing operations and building on past success in order to maximize unitholder value.

Subsequent to the end of the quarter, on August 1, 2008, Algonquin issued 3.5 million trust units as part of its acquisition of certain assets of Highground Capital Corp ("Highground"). Consideration for the units is cash in an amount between $22.2 and $23.7 million, dependent on the final proceeds of realization of certain Highground investments, together with the return of notes with an aggregate face value of approximately $4.8 million issued by Algonquin affiliates related to its St. Leon and Brampton Cogeneration projects. Cash received on the issuance of units will be used to reduce amounts outstanding on Algonquin's revolving operating and acquisition credit facilities.

The transaction represented a cost effective opportunity for Algonquin Power to access the capital markets on an attractive basis, without payment of the typical offering costs or discounts. Although a modest sized transaction, this equity issuance will enhance Algonquin Power's flexibility to further the growth opportunities currently being pursued.

During the first quarter of 2008, Algonquin Power announced that its Trustees had adopted a Unitholder Rights Plan (the "Rights Plan"). The Rights Plan was adopted to ensure the fair treatment of unitholders in connection with any take-over offer for the Company, and to provide the Trustees and unitholders with additional time to fully consider any unsolicited take-over bid. The Rights Plan also provides the Trustees more time to pursue, if appropriate, other alternatives to maximize unitholder value. During the second quarter, on April 24, 2008, at Algonquin Power's Annual and Special Meeting, the Rights Plan was approved by unitholders and subsequently received regulatory approval. The Rights Plan was not adopted in response to any specific proposal to acquire control of the Company.

Financial Summary for the second quarter of 2008:

- Revenue of $54.2 million in Q2 2008 as compared to $47.8 million in Q2 2007.
- Net earnings from continuing operations of $8.0 million or $0.11 per trust unit in Q2 2008 as compared to net loss of $2.6 million or $0.04 per trust unit in Q2 2007.
- Cash available for distribution of $15.9 million or $0.21 per trust unit in Q2 2008 as compared to $18.9 million or $0.25 per trust unit in Q2 2007. Distributions for the second quarter of both 2008 and 2007 were $0.23 per trust unit.

Financial Summary for the first six months of 2008:

- Revenue of $102.2 million for the first six months of 2008 as compared to $95.4 million in the first six months of 2007.

- Net earnings from continuing operations of $6.5 million or $0.09 per trust unit for the first six months of 2008 as compared to $4.3 million or $0.06 per trust unit for the first six months of 2007.
- Cash available for distribution of $31.8 million ($0.42 per trust unit) in the first six months of 2008 as compared to $34.0 million ($0.45 per trust unit) for the same period in 2007. Distributions for both the first half of 2008 and 2007 were $0.46 per trust unit.

Power Generation & Development Highlights

Renewable Energy Division

During the second quarter of 2008, the Renewable Energy division produced sufficient energy to supply the equivalent of 62,700 homes with renewable power. Using new standards of thermal generation, renewable energy production saved the equivalent of 155,000 tons of CO_2 gas from entering the atmosphere in the second quarter of 2008.

During the second quarter of 2008, revenue from energy sales in the Renewable Energy division totalled $19.7 million as compared to $12.6 million during the same period in 2007. During the quarter, the division generated electricity equal to 97% of long term projected average resources (wind and hydrology) as compared to 93% during the same period in 2007. The division experienced an increase in revenue primarily as a result of higher energy production due to above long term average resources in all regions except New York, Ontario and Manitoba where resources were below long term averages.

For the second quarter of 2008, operating profit totalled $14.5 million as compared to $14.4 million during the same period of 2007. Overall, the Renewable Power division exceeded Algonquin's expectations due to greater than long term average resource availability for both wind and hydrology.

The Renewable Energy division is expected to perform at or above long term averages in the third quarter of 2008. In addition, the facilities in the New England region are expected to continue to benefit from improved market rates as compared to the rates experienced in 2007.

Thermal Energy Division

During the second quarter of 2008, operations at the Thermal Energy division's Energy-from-Waste facility resulted in the diversion of 26,500 tonnes of waste from landfill sites.

Revenue for the second quarter of 2008 totalled $25.9 million as compared to $21.1 million during the same period in 2007. The increase in revenue was primarily due to a 5,500 MW-hr increase in production at the Sanger cogeneration facility as a result of the recent successful re-powering project. In addition, throughput at the Energy-from-Waste facility increased by 14,600 tonnes over the same period in 2007, resulting in increased waste disposal sales.

For the second quarter of 2008, operating profit totalled $7.6 million, as compared to $6.4 million during the same period in 2007. Overall, the Thermal Energy division did not meet the Company's expectations due to increased operating expenses related to the division's landfill gas facilities.

With no upcoming planned major outages, the Windsor Locks and Sanger facilities are expected to continue to operate through 2008 in line with Algonquin's long term expectations. The Energy-from-Waste facility is expected to continue operating at current levels throughout the remainder of the year. Overall management anticipates the Thermal division to meet expectations for the remainder of the year.

Development Division

The Development division is actively identifying and developing new opportunities in the renewable and thermal divisions in addition to pursuing growth projects within Algonquin's existing portfolio. Currently the group is pursuing a number of wind, hydroelectric and thermal energy projects at varying stages of development.

During the quarter, the Development division completed and commissioned the steam supply project at the Energy-from-Waste facility and transferred the project to the Thermal Energy division. The project now successfully provides approximately 90,000 pounds of steam per hour to a nearby recycled paper board mill for use in its manufacturing process, and is expected to generate $1.5 million in cash from operations annually.

At Algonquin's existing facilities, the Development division is reviewing proposals at the Energy-from-Waste facility to expand its power generation and waste processing throughput capacity. These projects could increase the generating capacity at the facility and increase waste processing throughput by over 100,000 tonnes annually. A feasibility study is currently being completed to assess expected capital and operating costs of an expanded facility. The Development division is also reviewing its options to market the increased capacity at the Sanger Facility that resulted from the re-powering project. This would increase the capacity at the facility by 14 MW.

The likelihood of Algonquin proceeding with these projects is unknown at this time as the projects are in the early stages of development.

Utility Services Highlights

Water Distribution and Wastewater Treatment

During the second quarter of 2008, operations at the Utility Services provided approximately 1.5 billion U.S. gallons of water to its customers, treated approximately 450 million U.S. gallons of waste-water and sold approximately 150 million U.S. gallons of treated effluent.

Revenue for the second quarter of 2008 in Utility Services totalled $8.7 million, consistent with the same period in 2007. Overall the water and waste-water treatment customer base grew marginally compared to last year at this time. The flat revenue is attributed to an increase in revenue due to a rate increase at the Gold Canyon facility and organic growth, offset by a reduction in revenue as a result of the stronger Canadian dollar.

For the second quarter of 2008, operating profit totalled $4.9 million as compared to $5.4 million during the same period in 2007. Overall, Utility Services did not meet the Company's expectations due to higher operating costs and slower growth which reduced demand for utility services.

Utility Services is expecting a continued lowered organic growth rate with approximately 4% average organic growth forecasted for 2008 due to the slowdown in the U.S. housing market.

However, the business unit continues to provide service in one of the faster growing Counties, Maricopa County, in the United States. In addition, Utility Services is preparing to initiate rate cases at five of its Arizona facilities during the remainder of 2008. It is anticipated that regulatory review of the rates and tariffs for these five facilities would be completed in the second half of 2009. The resolution of rate cases is expected to positively impact results in Utility Services.

Outlook

Algonquin Power is expected to meet Management's expectations during the third quarter of 2008, assuming continuing operational improvements, organic growth, and resource conditions at or above long term averages during the quarter. Algonquin Power will continue to focus on improving performance and efficiently managing operations throughout the remainder of 2008, while focusing on growing its portfolio of renewable, thermal, and utility assets, both organically and through acquisition of new facilities.

Algonquin Power continues to be a reliable yet exciting opportunity for investors seeking stable returns from a socially accountable and environmentally responsible company operating in the clean, renewable energy and sustainable infrastructure businesses.

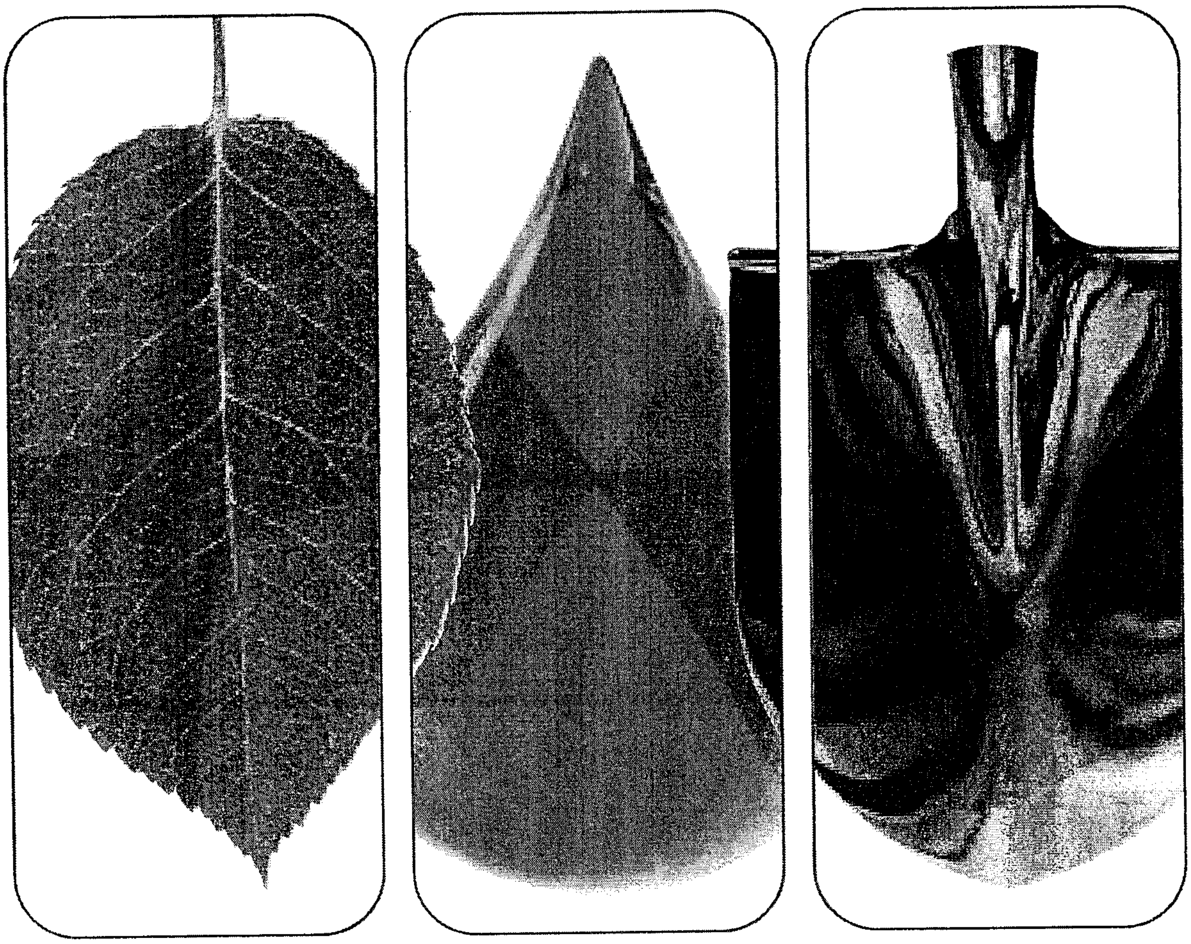
Thank you for your continued interest in Algonquin Power. You are encouraged to obtain further detail about the performance of the Company in the second quarter 2008 Management's Discussion & Analysis that follows.

K Moore

Ken Moore
Chairman

Third Quarter Report

September 30, 2008



Algonquin Power

Report to Unitholders

Business Review

Recently, on October 20, 2008, Algonquin Power announced that its Board of Trustees approved a plan geared to maximize long-term unitholder value and strengthen its position as a strong, growth-oriented renewable energy and utility infrastructure company. The forces driving the new strategic direction include the change in taxation policies facing income trusts in 2011, the continuing volatility in the foreign exchange environment, and the turbulence evident in the financial markets. Given these market forces, the Board established a distribution level that is sustainable and provides the ability to focus on development projects and strategic growth opportunities that are present in the current market. Internally, Algonquin Power has focused on realigning its operations into two major business units: Power Generation & Development, and Utility Services. The re-alignment was completed in order to more effectively position Algonquin Power to compete in the clean, renewable energy and utility services business sectors.

To support the creation of value through growth, the Development division will continue to focus on renewable and high efficiency thermal energy generation projects in North America with five full time employees based out of the head office. The team is working to actively identify, develop and construct new renewable and high efficiency thermal energy generating facilities as well as to identify, develop and construct other projects that maximize the potential of Algonquin's existing facilities. Currently, the Development division is actively working on several wind projects in Ontario, has obtained a Power Purchase Agreement for a 25 MW wind project in Saskatchewan, and is pursuing the re-development of the Windsor Locks facility in Connecticut. Further detail regarding Algonquin Power's development activities are outlined below.

During the third quarter of 2008, Algonquin Power and Highground Capital Corp. ("Highground") completed a business combination whereby Highground amalgamated with a subsidiary of its manager and an Algonquin subsidiary, and shareholders of Highground received 0.9749 trust units of Algonquin Power for each common share formerly held in Highground. Algonquin Power issued approximately 3.5 million trust units in connection with the transactions and to date has received net cash in an amount of $18.6 million, the return of $4.8 million in notes that were issued by Algonquin affiliates related to its St. Leon and Brampton Cogeneration projects, and a note receivable of $2.8 million. The amalgamation represented a cost effective opportunity for Algonquin Power to access the capital markets on an attractive basis, without payment of the typical offering costs or discounts. Although a modest sized transaction, this equity issuance will enhance Algonquin Power's flexibility to further the attractive growth opportunities currently being pursued.

Financial Summary for the third quarter of 2008:

- Revenue of $55.1 million in Q3 2008 as compared to $46.4 million in Q3 2007.
- EBITDA of $22.2 million in Q3 as compared to $22.8 million in Q3 2007
- Net loss from continuing operations of $4.4 million or $0.06 per trust unit in Q3 2008 as compared to net earnings of $13.0 million or $0.18 per trust unit in Q3 2007.
- Cash available for distribution of $15.2 million or $0.19 per trust unit in Q3 2008 as compared to $18.5 million or $0.24 per trust unit in Q3 2007. Distributions for the third quarter of both 2008 and 2007 were $0.23 per trust unit.

Financial Summary for the first nine months of 2008:

- Revenue of $157.3 million for the first nine months of 2008 as compared to $141.9 million in the first nine months of 2007.
- EBITDA of $66.8 million for the first nine months of 2008 as compared to $67.7 million in the first nine months of 2007

- Net earnings from continuing operations of $2.1 million or $0.03 per trust unit for the first nine months of 2008 as compared to $17.3 million or $0.24 per trust unit for the first nine months of 2007.
- Cash available for distribution of $47.0 million ($0.61 per trust unit) in the first nine months of 2008 as compared to $52.4 million ($0.69 per trust unit) for the same period in 2007. Distributions for both the first nine months of 2008 and 2007 were $0.69 per trust unit.

Power Generation & Development Highlights

Renewable Energy Division

During the third quarter of 2008, the Renewable Energy division produced sufficient energy to supply the equivalent of 56,400 homes with renewable power. Using new standards of thermal generation, renewable energy production saved the equivalent of 140,000 tons of CO2 gas from entering the atmosphere in the third quarter of 2008.

During the quarter, revenue from energy sales in the Renewable Energy division totalled $16.9 million as compared to $9.2 million during the same period in 2007. The Renewable Energy division generated electricity equal to 115% of long term projected average resources (wind and hydrology) as compared to 84% during the same period in 2007. The division experienced an increase in revenue primarily as a result of higher energy production due to significantly higher than long term average resources in all regions where Algonquin operates renewable energy facilities.

For the third quarter of 2008, operating profit totalled $11.6 million as compared to $12.8 million during the same period of 2007. Overall, the Renewable Power division exceeded Algonquin's expectations due to greater than long term average resource availability.

The Renewable Energy division is expected to perform at or above long term averages in the fourth quarter of 2008. In addition, the facilities in the New York and New England region are expected to continue to benefit from improved market rates as compared to the rates in 2007.

Thermal Energy Division

During the third quarter of 2008, operations at the Thermal Energy division's Energy-from-Waste facility resulted in the diversion of 29,300 tonnes of waste from landfill sites.

Revenue for the third quarter of 2008 totalled $29.0 million as compared to $23.3 million during the same period in 2007. The increase in revenue was primarily due to the sale of steam to a nearby manufacturing facility, an increase in production at the Sanger cogeneration facility as a result of the recent successful re-powering project, and an increase in production at Algonquin's landfill gas facilities. In addition, throughput at the Energy-from-Waste facility increased 10.8% over the same period in 2007, resulting in increased waste disposal sales.

For the third quarter of 2008, operating profit totalled $8.9 million, as compared to $9.6 million during the same period in 2007. Overall, the Thermal Energy division did not meet the Company's expectations due to increased operating expenses related to the division's landfill gas facilities.

With no upcoming planned major outages, the Windsor Locks and Sanger facilities are expected to continue to operate in line with expectations and the Energy-from-Waste facility is expected to continue operating at current levels throughout 2008. Overall management anticipates the Thermal division to meet expectations for the remainder of the year.

Development Division

The Development division is working to actively identify, develop and construct new renewable and high efficiency thermal energy generating facilities as well as to identify, develop and construct other projects that maximize the potential of Algonquin Power's existing facilities. The strategy is to focus on projects that benefit from low operating costs using proven technology that can generate sustainable and increasing cash flows in order to achieve a high return on invested capital. In addition to Greenfield development and expansion of Algonquin Power's existing portfolio, the Development division actively seeks out accretive renewable and clean energy acquisition opportunities.

Every acquisition and development project is subject to a significant level of due diligence and financial modeling to ensure it satisfies the financial objectives of Algonquin Power and as such the likelihood of proceeding with acquisitions or projects depends on the outcome of these activities. Currently, the Development Division is working on the following projects:

- The Red Lily Wind Project which is a 25 MW project in south-western Saskatchewan. A Power Purchase Agreement with SaskPower has been executed following the successful bid into a SaskPower Environmentally Preferred Power Strategy Request for Proposal. The team has submitted a Notice of Project Application with Natural Resources Canada under the ecoENERGY for Renewable Power Program, and the Environmental Assessment is expected to be submitted to the appropriate agencies in the fourth quarter.
- Following the successful re-powering of the Sanger cogeneration facility and as the current Windsor Locks Power Purchase Agreement reaches maturity in 2010, a variety of options for alternative sales of thermal energy or re-powering of the facility are being fully reviewed.
- Also as a result of the re-powering of the Sanger facility, 14MW of additional production is available in excess of what is currently being sold under the existing Power Purchase Agreement under which the facility operates. The Development division is currently reviewing the options to market this increased capacity at the Sanger Facility.
- Algonquin Power is exploring options to build on the success of the St. Leon Wind Energy project including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 150 MW.
- Algonquin is maintaining land option agreements for two wind projects in Quebec in anticipation of a Hydro Quebec Call for Tender expected in the fourth quarter of 2008 or the first quarter of 2009 for wind projects of a maximum 25 MW size. In addition, Algonquin has maintained a relationship with a development co-op comprised of landowners and other small investors for the potential development of a third project in response to the expected Call for Tender.
- Algonquin Power, through Windlectric Inc., a corporation formed to pursue the development of a wind power project in Ontario as well as other opportunities across Canada is currently pursuing an 80 MW wind project in Ontario.
- The Development division is currently reviewing several proposals at the Energy-from-Waste facility to expand its power generation and waste processing throughput capacity. An investment of approximately $250 million is being contemplated which could increase the generating capacity at the facility and increase waste processing throughput by over 100,000 tonnes annually or 275 tonnes per day.
- In addition, several new wind energy projects, including five wind projects in Canada having a potential generation capacity of over 150 MW, hydroelectric projects at different stages of investigation, and opportunities for involvement in a 19 MW combined cycle high efficiency thermal energy generation project.

Utility Services Highlights

Water Distribution and Wastewater Treatment

During the third quarter of 2008, Utility Services operations provided approximately 1.8 billion U.S. gallons of water to its customers, treated approximately 450 million U.S. gallons of waste-water and sold approximately 195 million U.S. gallons of treated effluent.

Revenue for the third quarter of 2008 in Utility Services totalled $9.2 million, consistent with the same period in 2007. The water distribution customer base grew 1.3% over last year and the waste-water treatment customer base grew 2.1% compared to last year at this time. The flat revenue is attributed to an increase in revenue due to organic growth and increased demand at seven utility services facilities, offset by decreased demand at ten utility services facilities.

For the third quarter of 2008, operating profit totalled $4.9 million as compared to $5.8 million during the same period in 2007. Overall, Utility Services did not meet the Company's expectations due to higher operating costs and the stronger Canadian dollar.

Utility Services is expecting continued lower organic customer growth for the remainder of 2008 due to the slowdown in the U.S. housing market. Rate cases at six facilities in Arizona and four facilities in Texas will be initiated over the next few quarters, with new rates to begin in 2010. Utility Services management continues to pursue accretive acquisition opportunities to expand operations in existing geographies and to acquire utilities in areas expecting higher growth over the long term.

Outlook

Algonquin Power's portfolio of clean, renewable energy and utility assets are expected to continue performing well throughout the fourth quarter of 2008, assuming continuing operational improvements, organic growth, and resource conditions at or above long term averages during the quarter. The company is actively working on many exciting initiatives in order to create value through growth and continues to focus on improving performance and efficiently managing operations of the existing portfolio.

The Board of Trustees would like to note that despite the recent market volatility, Algonquin Power remains in a strong position with respect to the Fund's immediate and long-term debt position and as usual will continue to monitor its ongoing capital expenditure program with a view to maximizing the long term value of these investments for unitholders. With the unitholder distribution set at a long-term sustainable level, Algonquin will have the financial resources and flexibility to invest in growth and capitalize on emerging opportunities which is a key element of the Algonquin Power value proposition.

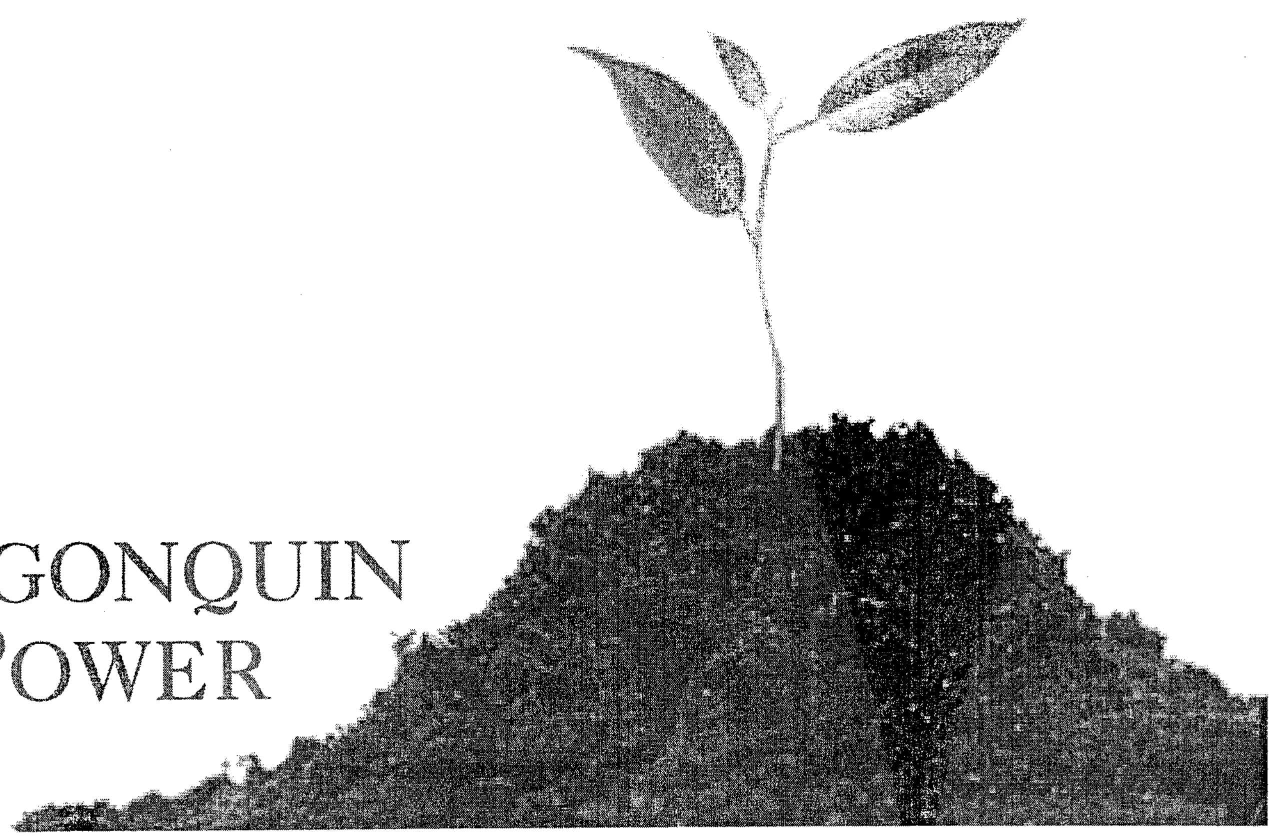
Thank you for your continued commitment to Algonquin Power. You are encouraged to obtain further detail about the performance of the Company in the third quarter 2008 Management's Discussion & Analysis that follows.

(signed) Ken Moore

Ken Moore
Chairman

re:GENERATING

Q1/2009



ALGONQUIN POWER

Report to Unitholders

I am pleased to report that Algonquin had a successful first quarter of 2009, posting increased revenue, growth in adjusted net earnings, and stable EBITDA, which are very positive results in light of the current economic climate and global business environment. Algonquin Power has grown since 1997 with a focus on stabilizing cash-flow, mitigating risk, and growing conservatively. Algonquin's portfolio of assets has a low-risk business profile backed by long-term contracts in regulated industries, which has clearly resulted in a company that can successfully weather through a recessed economy.

During the first quarter, Algonquin focused efforts on debt reduction, reducing funds drawn on the credit facility by 5%, demonstrating progress in the goal of improving financial flexibility during this challenging economic climate. These efforts have placed Algonquin in a unique position to continue progressing with our goals to invest in the business and to be able to leverage emerging growth opportunities.

Demonstrating a successful growth strategy, on April 23, 2009, Algonquin was pleased to announce plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. Algonquin Power and Emera will each own 50% of the newly formed California Pacific Electric Company, which intends to acquire the California-based electricity distribution and related generation assets of NV Energy, Inc. This is a very positive step in strengthening the utilities business and leveraging Algonquin's proven utility management and independent power generation expertise, while Emera brings an undeniable wealth of expertise and experience owning and operating local electrical distribution utilities to the transaction. This transaction enhances Algonquin's cash flow quality and stability and will contribute to the long-term success of Algonquin Power.

Further on the plans for growth, Algonquin continues to focus on pursuing additional acquisitions of high quality assets that will contribute to long-term stability of the company, as well as through Greenfield development and projects within our existing assets.

In the Renewable Energy division, we have been successfully progressing with the Red Lily Wind Project in south-eastern Saskatchewan and have a Power Purchase Agreement with SaskPower in place for the 25 MW first phase of the facility, and recently Algonquin received several important provincial and federal approvals for the project. Additionally in the Renewable Energy division, Algonquin continues to explore options to build on the success of the St. Leon Wind Energy project, including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. These projects have a potential generation capacity of over 85 MW. We are also very encouraged by discussions with the Ontario Power Authority that indicate that energy procurement initiatives in Ontario will be positively influenced by the Green Energy Act introduced recently by the Ontario government. In anticipation of this, the Development division is working on several projects totalling approximately 250 MW that may qualify under the Green Energy Act.

In the Thermal Energy division, we are moving forward with plans to market an additional 14MW of production from our Sanger Cogeneration facility as a result of the major re-powering project completed in 2007. Of the 14 MW, an additional 6 MW can be exported with the existing facility while an upgrade of the line voltage by Pacific Gas and Electric Company is required to access the full 14 MW. The line upgrade is anticipated during or after 2010, while we are expecting to reach agreement on the sale of the 6 MW of power beginning in the second half of 2009. Additionally in the Thermal Energy division, Algonquin is pursuing the re-development of the Windsor Locks facility in Connecticut, as the Power Purchase Agreement reaches maturity in 2010. A variety of options for alternative sales of energy or re-powering of the facility are being considered and we will keep you updated as we move forward.

In the Utility Services division, we have been focused on investing in the assets over the past several years and as a result we are in the process of filing and initiating rate adjustments with the regulators at a number of facilities which are expected to result in increased rates for services provided. While a firm forecast of rate increases is not possible, the potential result is an expected increase in annual EBITDA of more than $10 million by mid-2010.

While we will continue to focus on conservatively managing the business, our direction will also be on managing for the long-term success of the company while growing investor value. Your continued commitment to investing in clean, renewable power and sustainable infrastructure is valued by us. You are encouraged to obtain further detail about the performance of the Company in the Management's Discussion & Analysis. Thank you for your continued interest in Algonquin Power.

(signed) Ken Moore

Ken Moore
Chairman

re:GENERATING

Q2/2009

ALGONQUIN
POWER

Report to Unitholders

In the second quarter of 2009, Algonquin showed positive results, with production in line with expectations, however revenue and EBITDA fell slightly below expectations primarily as a result of lower average energy rates due to the current global business environment. Algonquin Power's diversified asset base backed by long-term contracts serve us well during these times to stabilize cash-flow and mitigate risk. This approach enables Algonquin to continue to successfully execute its growth plans, even in uncertain economic times. Algonquin's business strategy is to maximize long term investor value by strengthening its position as a strong, successful renewable energy and infrastructure company and focusing on growth in cash flow and earnings.

During the second quarter, Algonquin focused efforts on reinvesting in the business and emerging growth opportunities, always keeping in mind our long term goal of increasing investor value. Our commitment to growing our business was further demonstrated by our announcement on April 23, 2009, to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. Algonquin Power and Emera will each own 50% of the newly formed California Pacific Electric Company, which intends to acquire the California-based electricity distribution and related generation assets of NV Energy, Inc. Emera brings a high level of expertise and experience owning and operating electrical distribution utilities to the partnership. This transaction further enhances the quality of Algonquin's cash flows and will contribute to the long-term success of your investment. We view this as a very positive step in strengthening our utilities business and leveraging our proven utility management and independent power generation expertise.

Also during the second quarter, on June 12, 2009, the trustees of Algonquin announced that they had entered into a unit-share exchange support agreement to support an offer which will provide Algonquin's unitholders the opportunity to exchange their trust units of Algonquin for common shares of a corporation. If the offer is accepted, Algonquin unitholders will receive common shares of the corporation in exchange for their trust units of Algonquin on a one-for-one basis. The shares of the corporation will continue to receive the same monthly dividend equal to current distribution on units of the Fund, which is presently $0.24 per unit annually. The shares will be listed for trading on the Toronto Stock Exchange. In addition to the exchange of Algonquin's trust units for shares, a proposal has been made to holders of Algonquin's convertible debentures to exchange convertible debentures for newly issued convertible debentures or shares of this same corporation. Additional details of the offers are available on Algonquin's website.

The Board of Trustees believe that the unit for share exchange, once completed, will further position Algonquin Power as a growth company within the capital markets and will increase Algonquin Power's competitive effectiveness in the power and utility sectors.

I am also pleased to report that on July 27, 2009, at the Annual and Special Meeting of Unitholders, Chris Huskilson was appointed to the Board of Trustees of Algonquin Power. Mr. Huskilson is currently the President and Chief Executive Officer of Emera Inc., having held this position since November 2004. Mr. Huskilson is also a director of Emera Inc. and Nova Scotia Power Inc., and the chairman of Bangor Hydro-Electric Company. The addition of Mr. Huskilson to the Board of Trustees is very positive for Algonquin Power, both from a corporate governance perspective and from being able to build on the relationship in the future to create additional opportunities for Algonquin to grow.

In the Renewable Energy division, we have been successfully advancing the Red Lily Wind Project in south-eastern Saskatchewan. A Power Purchase Agreement with SaskPower is in place for the 25 MW first phase of the facility, and recently Algonquin executed an agreement under the ecoENERGY for Renewable Power Program securing some of the funding for the project. The project has also satisfied the provincial environmental assessment requirements. Additionally in the Renewable Energy division, Algonquin continues to explore options to build on the success of the St. Leon Wind Energy project, including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. Algonquin is progressing with the provincial environmental assessment for these projects that have a combined potential generation capacity of over 85 MW. In Ontario, the government is working to develop regulations to implement the Green Energy Act. We are encouraged by this progress and have been working on a number of projects which may qualify under the Green Energy Act totalling approximately 100 MW.

In the Thermal Energy division, we are moving forward with evaluations regarding the re-contracting of the Windsor Locks co-generation facility. The current Power Purchase Agreement with Connecticut Light & Power expires in 2010 and a number of options are being considered including maximizing net revenue from the existing equipment, and a repowering of the facility. At the Sanger facility, efforts to market an additional 14MW of production as a result of the major re-powering project completed in 2007 continue. On the Greenfield development side, the Development Division has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. Algonquin believes this project is an excellent fit for the Minister of Energy and Infrastructure's directive to procure electricity from combined heat and power projects.

In the Utility Services division, we are focused on several applications for rate increases that have been initiated over the past few quarters that are necessary in order to achieve the stipulated regulatory return on the investments that have been made in the utilities over the past several years. These rate applications are expected to result in increased rates for services provided, and while a firm forecast of rates is not possible, the potential result is an expected increase in revenue of more than $10 million over the course of 2010.

True to our strategy, Algonquin Power had a very active second quarter, making two major announcements that will, once completed, contribute to realizing our long-term goal of maximizing investor value. Algonquin is committed to investing in the business, identifying appropriate growth opportunities and remaining focused on value creation. You are encouraged to obtain further detail about the performance of the Company in the Management's Discussion & Analysis. Thank you for your continued interest in Algonquin Power.

(signed) Ken Moore

Ken Moore
Chairman of the Trustees