AMERICAN ARBITRATION ASSOCIATION
Commercial Arbitration Tribunal

No. 11 198 Y 002014 12	)
In the Matter of an Arbitration between:	)
WINOOSKI ONE PARTNERSHIP	)
Claimant,	)
-and-	)
CITY OF BURLINGTON,	)
Respondent.	)

FINAL AWARD OF ARBITRATORS

THE UNDERSIGNED ARBITRATORS, having been designated in accordance with the arbitration agreement dated December 12, 1991 entered into between the Claimant, Winooski One Partnership, a general partnership organized under the laws of the State of Vermont, (hereafter or "Claimant" or "WOP") and City of Burlington, a Vermont municipal corporation, acting by and through the Burlington Electric Department, (hereafter "Respondent" or "BED"), collectively ("Parties"), having been duly sworn, having duly heard the proofs and allegations of the

Parties, do hereby find, conclude and issue this FINAL AWARD OF ARBITRATORS, as follows:

This arbitration arises out of an agreement pursuant to which BED was granted an option to acquire all of WOP's title and interest in the Winooski One Hydro Facility, Chase Mill Hydroelectric Project, FERC P-2756 (the "Facility"), a 7.455 MW (nameplate) hydropower installation on the Winooski River in Burlington, Vermont. WOP developed the Facility pursuant to the terms of Agreement for Hydroelectric Project Development ("Agreement") dated September 30, 1986, as restated and amended on December 12, 1991, between the BED and WOP. (Ex.1)[1] The Agreement granted BED an option to purchase all of WOP's right, title and interest in the then-to-be built Facility (subsequently completed in 1993), pursuant to the terms of an Option Agreement of even date, as amended on December 12, 1991 (the "Option Agreement"). Paragraph 3 of the Option Agreement provides:

> 3. <u>Purchase Price</u>–To exercise this Option and purchase the Project, BED shall pay to WOP the fair market value of the Project following the termination of the 20-Year Levelized Purchase Contract with the Vermont Power Exchange, Inc. If the Parties cannot agree on the fair market value, the matter shall be subject to the arbitration provisions of the Amended and Restated Agreement for Hydroelectric Project Development executed by the Parties on even date herewith...

[1] The underlying land and water rights are owned by BED and leased to WOP pursuant to a Lease Agreement dated December 12, 1991. The Lease Agreement is for an initial term of the inception date of the Facility's FERC license through its expiration (2028). The Lease Agreement also grants the Lessee the option to renew the term for an additional 30-year period. (Ex. 2)

The arbitration provision of the Agreement provides in part:

> 21. <u>Arbitration</u>
>
> Any controversy or claim arising out of or relating to this Agreement, for the breach thereof, shall be settled by arbitration at Burlington, Vermont, in accordance with the Commercial Arbitration Rules then obtaining of the American Arbitration Association, and judgment upon the award rendered by the arbitrator(s) may be entered in any court having jurisdiction thereof... The decision of the arbitrators shall determine and specify how the expenses of the arbitration shall be allocated between the Parties.

The PURPA agreement with the Vermont Electric Power Exchange, subsequently assigned to the Vermont Electric Power Producers Inc., referenced in paragraph 3 of the Agreement, expired at midnight on March 31, 2013. On September 26, 2012 BED duly notified WOP, pursuant to paragraph 4 of the Option Agreement, of its intention to exercise its Option rights.

A dispute over the fair market value of the Facility as at April1, 2013 arose between the Parties. In accordance with the provisions of Paragraph 3 of the Option Agreement, on December 10, 2012, Claimant filed Demand For Arbitration with the American Arbitration Association ("AAA"). Respondent duly filed its Answering Statement with the AAA on December 27, 2012.

THE ARBITRATION HEARING

The undersigned arbitrators (hereinafter referred to as the "Tribunal") were appointed and sworn to hear this dispute in accordance with the requirements of the Parties' arbitration agreement, and the Commercial Arbitration Rules ("Rules") of the AAA.

Prior to the Arbitration Hearing, the Tribunal entered Pre-Hearing Orders Nos. 1-6 establishing procedures for the arbitration, and resolving certain discovery and procedural disputes. Among other things, Pre-Hearing Order No. 1 confirmed a stipulation by the Parties that this arbitration would proceed in accordance with the AAA's Commercial Arbitration Rules ("Rules") and the AAA's Optional Procedures for Large, Complex Commercial Disputes ("LCCP"). In addition, the Parties confirmed that the substantive legal issues in this arbitration would be governed by the laws of the State of Vermont and the Vermont Arbitration Act, 12 V.S.A., Chapter 192 as amended.

Pre-Hearing Order No. 1 also set a pre-hearing schedule and the dates for the Arbitration Hearing, all of which were agreed upon by the Parties, and confirmed the agreement of the Parties that the form of award to be issued in this matter would be a reasoned award.

In accordance with the stipulation of the Parties, the issues to be determined by the Tribunal was limited to: (1) the fair market value of the Winooski One hydroelectric facility as of April 1, 2013 and (2) the value of a discount, if any, on the to-be-determined fair market value of the power plant for the period between April 1, 2013 and the date of the Award, all of which was described in Pre-Hearing Order 1. The oral stipulation was subsequently reduced to writing by the Parties and submitted in letter from to the AAA on March 27, 2013. The letter reads in part:

> ... the primary issue to be determined in this arbitration is the fair market value of the Winooski One hydroelectric facility as of April 1, 2013.... In addition...the City of Burlington raised the issue of 'the value of discount, if any, on the to be determined fair market value of the power plant for the period between April 1, 2013 and the date of the Award...This will confirm that the parties have agreed to share equally in the costs of the arbitration and, consistent with the American Rule, each party will bear its own attorneys' fees.

Pursuant to notice, the Arbitration Hearing in this matter was held in Burlington, Vermont between September 30 and October 4, 2013. The hearing was continued in New York, New York between November 7 and 8, 2013. WOP was represented at the hearing by its counsel Robert B. Hemley and David A. Boyd of Gravel & Shea. BED was represented by its counsel, William F. Ellis of McNeil, Leddy & Sheahan P.C.

At the Arbitration Hearing, the Parties presented opening statements, submitted documentary exhibits and called witnesses to give testimony both in person and by deposition.[2]

At the conclusion of the presentation of expert testimony on November 8, 2013, the Tribunal inquired of counsel, in accordance with R-35 of the Rules, whether they had any further proofs to offer or witnesses to be heard on the substantive issues in dispute in the case. Counsel for each party replied to this inquiry in the negative. (Tr., 1083-04) Accordingly, the Tribunal finds that all evidence pertinent and material to the substantive issues in dispute in this controversy that the Parties wished to offer was received into evidence and heard at the Arbitration Hearing, and that the Parties so stipulated at the conclusion of the hearing.

Closing arguments were presented on November 8, 2013 in New York, New York. Post-hearing briefs were timely submitted on November 13, 2013. Following receipt of the post-hearing briefs, the record was declared closed as of November 16, 2013. (See Rules, R-35 and R-41).

Having heard the witnesses; having reviewed the exhibits, proofs, written submissions and legal authorities offered by the Parties; having heard the

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[2] The Parties engaged Depos Unlimited, Inc. to make a transcript of the hearing. Sherri L. Bessery recorded each of the hearing days except that Christina L. Boerner recorded part of the third day of the hearing. References to this transcript herein are designated "Tr. (page number)". A number of other Reporters were engaged to transcribe Trial Depositions and other Depositions. References to transcripts generated from such Depositions are herein designated "Surname Name, (page number)"

arguments of counsel; and otherwise having considered all of the evidence and other submissions offered, the Final Award of the Tribunal in this matter is as follows:

DISCUSSION

I. FAIR MARKET VALUE OF FACILITY AS AT APRIL 1, 2013

This Tribunal was asked to determine the fair market value of the Winooski One hydroelectric facility (the "Facility") as at April 1, 2013. Stated differently, the question is what would a willing buyer have paid a willing seller for the Facility on that date.

Meaning of Fair Market Value

A commonly accepted definition of market value is the most probable price which a property should bring in a competitive and open market under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus. Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby:

1. buyer and seller are typically motivated;

2. both parties are well informed or well advised, and acting in what they consider their best interests;
3. a reasonable time is allowed for exposure in the open market;
4. payment is made in terms of cash in United States dollars or in terms of financial arrangements comparable thereto; and
5. the price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.[3]

This definition is consistent with Vermont law. The Vermont Supreme Court has defined "fair market value" as follows:

> The fair market value of property is the price which the property will bring in the market when offered for sale and purchased by another, taking into consideration all the elements of the availability of the property, its use both potential and prospective, any functional deficiencies, and all other elements such as age and condition which combine to give property a market value. There is no one or controlling factor.

Bookstaver v. Town of Westminster, 131 Vt. 133, 136-37 (1973) (quoting *In re Heath,* 128 Vt. 519, 524 (1970)). One commentator explained:

> The "market" in this definition can be thought of as all the potential buyers and sellers of like businesses or professional practices. In the legal interpretations of fair market value, the willing buyer and willing seller are hypothetical persons, dealing at arm's length, rather than any particular buyer or seller. In other words, a price would not be considered representative of fair market value if it is influenced by special motivations not characteristic of a typical buyer or seller. SHANNON PRATT & ALINA V. NICULITA, THE LAWYER'S BUSINESS VALUATION HANDBOOK 2 (2d ed. 2010) ("PRATT & NICULITA")

[3]The Appraisal Institute, *The Appraisal of Real Estate,* Thirteenth Edition (2008), at 24.

Approaches to Value

The three approaches to valuation are: (i) sales comparison; (ii) income; and (iii) cost. The sales comparison approach to valuation assumes that an informed purchaser would pay no more for a property than the cost of purchasing an equally desirable substitute. The income approach to value is predicated upon the assumption that the market value of an income producing property is the present worth of future benefits (income) to be derived from owning the property. The cost approach to value is based upon the premise that a purchaser would pay no more for a property than the cost of producing an equally desirable substitute.

Vermont courts have acknowledged the three approaches to valuation and observed:

> '...there is no single pathway to th[e] goal' of determining fair market value. *Vermont Electric Power Co., Inc. v. Town of Vernon,* 174 Vt. 471, 474 (2002) (quoting *Gionet v. Town of Goshen,* 152 Vt. 451, 453 (1989)). "The court has noted that the cost approach, the income approach, and the market data approach offer the parties means of determining fair market value." *New England Power Co. v. Town of Barnet,* 134 Vt. 498, 505 (1976). "This list, however, is not exhaustive, and other methods may be used." *Lake Morey Inn Golf Resort v. Town of Fairlee,* 167 Vt. 245, 248 (1997). "In some cases, the [appraiser] may be required to use one approach exclusively in order to determine FMV [fair market value]; in other cases, the [appraiser] may have to use a different method or a combination of methods." *Id.* at 249. "This Court has held that any valuation method resulting in a rational determination of fair market value will survive scrutiny." *State Housing Authority v. Town of Northfield,* 2007 VT 63 ¶ 5, 182 Vt. 90, 93 (2007).

The Vermont Supreme Court however also noted that when valuing a hydroelectric facility, "the income-production of [the] hydroelectric facility will be extremely relevant, if not determinative, to its value." *USGen New England, Inc. v. Town of Rockingham*, 2004 VT 90 ¶3.

Expert Valuations Presented By Parties

The Claimant and the Respondent each retained the services of two highly regarded appraisers all of whom submitted expert reports. Winoosky One retained David C. Moody of Lumus Consultants International (hereafter the "Moody Report"-- Ex. 16 & 17) and George E. Sancoucy of George E. Sansoucy, P.E., LLC (hereafter the "Sansoucy Report" –Ex. 20 & 21). Burlington Electric retained the services of Daniel Peaco of La Capra Associates, Inc. (hereafter the "Peaco Report"-- Ex. 25 & 26)) and George Silver of George F. Silver & Associates (hereafter the "Silver Report"-- Ex 29 & 30). All are certified appraisers except for Mr. Peaco of La Capra Associates, Inc. who is an electric industry planning specialist.

Two out of the four appraisers utilized all three of the traditional models for valuation—sales comparison, income and cost. Mr. Moody did not use the sales approach because he "was not aware of any sales in New England that could be considered comparable to the Facility in terms of size and situation." Mr. Peaco did not find the cost approach to be an appropriate model and based his determination of value of the Facility on the income approach or discounted cash flow ("DCF") model supported with an analysis of comparable sales. Mr. Silver placed primary emphasis on the sales comparison approach using comparable properties located in a number of Northeast and Midwest states, and "moderate support" to the income approach, due to "current uncertainties in the market" and gave "very little weight" to the cost approach. (Silver Report.)

Valuation Summary of Experts

The valuation summary of the four appraisers can be presented as follows:

A. Moody

	Results
Sales Comparison Approach	N/A
Income Approach - Merchant	$20,014,000
Hypothetical Income Approach - QF	$26,446,000
Cost Approach – Value in Substitution	$31,942,000
Market Value of the Facility as at April 1, 2013	**$20,000,000 to $26,000,000**

B. Sansoucy

Sales Comparison Approach	$21,645,000
Income Approach - Merchant	$21,645,000
Hypothetical Income Approach - QF	N/A
Cost Approach – Value in Substitution	$21,750,000
Market Value of the Facility as at April 1, 2013	**$21,500,000**

C. Peaco

Sales Comparison Approach	$11,000,000
Income Approach - Merchant	$9,000,000
Hypothetical Income Approach - QF	N/A
Cost Approach – Value in Substitution	N/A
Market Value of the Facility at April 1, 201	**$10,000,000**

D. Silver

Sales Comparison Approach	$15,000,000
Income Approach - Merchant	$13,800,000
Hypothetical Income Approach - QF	N/A
Cost Approach – Value in Substitution	$16,400,000
Market Value of the Facility as at April 1, 2013	**$15,000,000**

The Discounted Cash Flow Model

It was previously noted that while all three models for valuation are appropriate valuation models, the primary model used for the valuation of hydroelectric plants is the income model or, more accurately, the discounted cash flow ("DCF") model. Three out of the four valuators, Mr. Moody, Mr. Sansoucy and Mr. Peaco, recognize that the most important factor for buyers and sellers of income producing properties is the income approach. Even Mr. Silver, who primarily employed the sales approach because, in his opinion, the variables utilized in the income approach were too uncertain to be effectively employed in the valuation of the Facility, gave "moderate" weight to the income approach. And the Respondent's main witness, Kenneth Nolan, Manager of Power Resources, at Burlington Electric, noted in response to a question from the Panel on how he employs the various investment models when making investment decisions as follows: "When you're negotiating these deals in the power market at least you're typically going to be looking at your cash flows and your expenses; so you're doing discounted cash flow." (Tr. 1734) At the end, when a deal is in place, it is "compared to other transactions that have occurred." (Tr. 1735)

WOP agrees: "... while the various appraisals present analyses based on discounted cash flow, comparable sales and the cost of replacing the Facility, there is essential agreement that buyers of a hydroelectric facility rely primarily on the discounted cash flow analysis. The other methodologies are more properly viewed as supportive, but not primary." (Winooski One Prehearing Brief at p.1-2)

Discount cash flow analysis uses future free cash flow projections and discounts them (most often using the weighted average cost of capital) to arrive at a present value, which is used to evaluate the potential for investment. The DCF model is a powerful tool. Nevertheless, it has its shortcomings. The model is merely a mechanical valuation tool. Small changes in the numerical inputs can have a dramatic effect on value -- hence the dispute between the Parties.

Although there are differences between the valuators in the inputs used to calculate the discount rate, and there is some difference of opinion with respect to certain Operation and Maintenance (O&M) expenses associated with the Facility (FERC relicensing costs, timing and cost of replacement of rubber dam etc.), and cost of capital, the relevant inputs of the DCF equation that go to the heart of the dispute between the Parties are found on the revenue side.

The Parties are in agreement that the three revenue inputs in dispute are: (A) future production levels of the Facility; (B) the price to be paid for power produced at the Facility (i) as a merchant plant with or without gas pipeline constraint and (ii) as a qualifying facility ("QF") under the Public Utilities Regulatory Practices Act of 1978 ("PURPA"); and (C) the future value of the Facility's environmental attributes (Massachusetts Class II Renewable Energy Certificates). Each of these inputs will be discussed in turn.

A. FUTURE PRODUCTION

The annual production estimates of the Parties vary substantially. WOP's expert witness Mr. Moody projected a progressive expansion of production (2013 to 2037) from 34,407 to 45,973 MWh and Mr. Sansoucy projected a straight-line average production of 33,300MWh, while Dr. DeGaetano projected average production of 34,051MWh. BED's expert witness Mr. Silver projected average production of 30,000MWh and Mr. Perry projected a base case 29,297 MWh and an upper limit case of 31,595 MWh. (Ex. 144; Winooski Post-Hearing Brief p. 5-6; Valuation Expert Reports.)

The differences between the Parties center around the effects of global warming and climate change on river flow at the Winooski River. WOP suggests that we are entering a new climatological paradigm resulting in more rain and progressively increasing river flow on the Winooski River resulting in greater power output. Furthermore, WOP maintains that due to climate change, future river flow projection needs to employ data using the most recent 15-year period rather than

30 years, which has traditionally been used in the hydroelectric power industry. While BED acknowledges global warming, it suggests the effect of climate change on river flow on the Winooski River is unknowable. Furthermore, the industry standard of analyzing river flow over a longer 30-50 year period is needed to account for cycles of high and low river flow that could last between 5 and 20 years.

WOP's theory was presented by two of its expert witnesses: Arthur T. DeGaetano, Professor of Earth and Atmospheric Science at Cornell University and director of the Northeast Regional Climate Center (" DeGaetano") and William R. Hackett, Associate Geologist at GES Groundwater & Environmental Services, Inc. ("Hackett").

Professor DeGaetano pointed to "numerous" climatological studies, including ones that he authored, showing increased precipitation in the northeastern United States over the past two decades, which the studies maintain will continue into the future. (See DeGaetano Expert Report Ex. 8; and Tr. 240). Due to climate change, traditional 30-year weather forecast models are no longer appropriate. Such models distort recent climatological developments and need to be replaced by a more representative 15-year model. Professor DeGaetano opined that the new 15-year model used for weather forecasting in general is equally applicable to forecast future precipitation, which in turn can be used to analyze river flow in general and on the Winooski River in particular. Professor DeGaetano testified that the optimal precipitation data that should be employed to predict future precipitation is one based on a 15-year model and not the traditional 30 year model[4] (Tr. 234); and that the increased precipitation will result in "increased river flow" (Tr. 230).

The Claimant's other expert witness, William Hackett, supported Professor DeGaetano's theory of increased river flow. Mr. Hackett developed his 2009 University of Vermont Master's thesis on the changing land-use, climate and hydrology in the Winooski River basin over a 70-year period. The thesis showed that over the study period the flow of the Winooski River has increased at a rate of .26 percent per year (2.6% per decade). Furthermore, Mr. Hackett used his Master's Thesis to argue that a strong statistical correlation exists between river flow and power production at the Facility over time, which, due to climate change, is evidenced by increased annual river flow and power production at the Facility over the past 15 years.

The Respondent relies on Meddia J. Perry, a Senior Hydrologist with Vanasse Hangen Brustlin, Inc. ("Perry") with over 20 years of experience measuring stream flow throughout New Hampshire and Vermont, including the Winooski River and the Winooski River basin.

In developing his model, Mr. Perry analyzed the upper and lower limits of the amount of flow at which the Facility can generate power (hydro power generation is flow rate times the hydraulic head--the elevation difference between the

[4] The Tribunal notes that on January 21, 2013, prior to being retained as an expert by WOP, Professor DeGaetano wrote: "There's probably no right answer" (BED Cross1; Tr. 236.)

headwater and the tail race). Since the variables are site-specific, an analysis was made of the hydraulic parameters of the Facility, including bypass flow determined to be 168 cubic feet per second ("CFS"). (Tr.1051-52). Further, Mr. Perry concluded that to start generation at the Facility a minimum flow of 450 CFS was needed and the maximum flow that the turbines could handle is 3,000 CSF. (Tr. 1054). According to his flow duration curves, Mr. Perry concluded that there is not enough flow 10% of the time and approximately 17% of the time flow is greater than the maximum capacity of the Facility.[5] (Tr. 1054) With respect to the representative time of daily flow data used, Mr. Perry utilized the power industry standard of 30-50 years in order to account for cyclicities of high and low flow periods, which can last between 5 and 20 years.[6] (Tr. 1062-63).

After developing his model with actual daily stream flow data, Mr. Perry performed a model calibration to determine how well modeled production correlated to actual production from the Facility from 1993 to 2011. The R squared analysis performed by Mr. Perry showed a very strong correlation of approximately 94 percent, indicating the accuracy of the model. (Tr. at 1070-71; Exhibit 101; Exhibit 23, Report at p.2.)

By contrast, Mr. Hackett simply correlated power production over time calculated

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[5] For input into his model, Mr. Perry obtained daily river flow data from the United States Geological Service at Essex gauge, located near the Facility.

[6] In fact, Mr. Perry used 26 years of daily stream flow data due to operational repairs at the Green Mountain Power Essex Number 19 facility (Waterbury Dam), an upstream peaking plant that had releases as little as 50 cubic feet per second prior to 1986. (Tr.1062-3).

annually and created a linear trend line in projecting future power production. In marked contrast to Mr. Perry, Mr. Hackett is a geologist whose present work focuses on soil remediation in connection with gas stations. (Tr.144-45). He has no expertise in hydroelectric power production. (Tr. 143). Mr. Hackett had no knowledge of the hydraulic parameters of the Facility: he did not know the maximum generating capacity of the Facility or the maximum amount of flow to achieve maximum production (Tr. at 151-52); the minimum flow necessary for the Facility to begin generating power (Tr. at 152); or the average capacity factor of the Facility (Tr. at 164). He did not run a river flow and power production model (Tr. at 157).

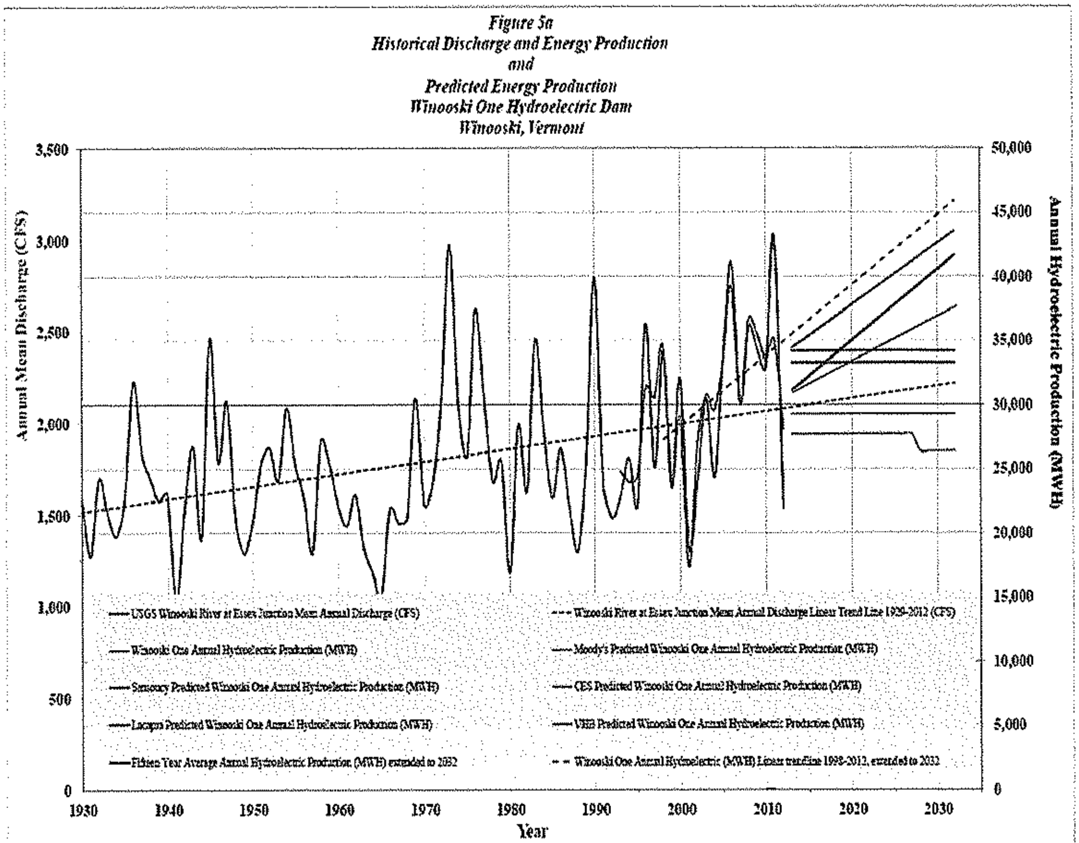
Professor DeGaetano's expertise is in climatology. While predicting increased river flow because of increase in precipitation, he did not know what those rates would be (Tr. 230) nor for that matter did he analyze Winooski River flow (Tr. 240), or statistical analysis of precipitation and river flow rates, or know what measuring station was closest to the plant, (Tr. 242), but rather relied upon visual correlation based on linear presentation river flow and precipitation (Tr. 255-56). Nor did Professor DeGaetano know the maximum generation capacity of the Facility, or how many CFS are necessary to achieve maximum production. (Tr. 249).

The Tribunal has carefully reviewed the testimony of Claimant's witnesses on future power production levels at the Facility and rejects their views as not persuasive. Mr. Hackett has no expertise in hydrology and his expertise is limited to his Master's Thesis documenting a .26% annual increase of river flow of the Winooski River over the last 70 years. While Professor DeGaetano is an eminent climatologist, he has no expertise in hydrology and certainly is not in the position to assist this Tribunal in determining future power production at the Facility.

Interestingly, neither Mr. Moody nor Mr. Sansoucy used the Claimant's expert witnesses to project future power production at the Facility. (By contrast, the Respondent's valuation witnesses, Mr. Peaco and Mr. Silver, relied on Mr. Perry's expertise for the purposes of including production levels at the Facility into their model.) Mr. Moody looked at the historical production numbers starting with a base in 2013 at 25,200 MWh, increasing production every year by 400-500 MWh per year through 2037, and culminating in an annual production of 45,973 MWh (Moody Report Ex. 16--attached Ex 1). Mr. Moody made these projections in spite of the fact that the Facility's historic capacity factor is 47 percent. By 2037, he projected a capacity factor of 70 percent.

Mr. Sancoucy took a 10-year period (2002-2011) of data and averaged them to arrive at his production figures for inclusion in his discounted cash flow analysis, which he set at 33,000MWh per year. (Sansoucy Report Ex. Ex 20). Mr. Sansoucy's demarcation point ignored 2012 production of 28,100 MWh, a down year, and excluded 2001 production of 17,373, the lowest year in the Facility's history. (Ex. 16 at 4). Mr. Sancoucy not only rejected using a 30-year historical comparison but also ignored, without explanation, Professor DeGaetano's suggestion that 15 years of data should be used (Tr. 272) or Mr. Hackett's opinion that a long 70-year trend should be used in combination with a shorter trend in order to "ignore cyclicities". (Tr. 110).

A presentation of Historical Discharge and Energy production and the Parties' expert projections is illustrated on the following graph.



The red trend line beginning at the fifteen year average (31,103 MWH) and increasing to 37,000 MWH represents Prof. DeGaetano's production projections.

The Tribunal previously noted that inputs can have a dramatic impact on DCF valuations—none more so than annual power production. The Tribunal is not persuaded by the extrapolation by WOP's climatologist, Professor DeGaetano, of current research on general weather patterns in the Northeastern United States to the Winooski basin[7] (Tr. 240), or by the predictions on annual river flow by its hydrologist, Mr. Hackett. However, we are much more convinced by Mr. Hackett's acknowledgment that no one knows the impact of climate change on river flow (Tr. 167).

Having carefully reviewed the testimony and written reports of the witnesses, the Tribunal concludes that Mr. Perry's base case scenario for future generation of the Facility is the most probable input that would be used by a reasonable buyer and seller in computing the fair market value of the Facility.

B. ENERGY PRICE

(i) Revenue as a Merchant Plant--- Pipeline Constraint

WOP's energy market expert, Olaf Karstens, testified that if future electricity price projections are correlated to gas prices,[8] and more particularly national gas prices based in Henry Hub, Louisiana; and if New England sources its natural gas from Algonquin City-Gates which, due to pipeline constraints in the New England region

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[7] It is not clear from the literature that Professor DeGaetano relied on to make his predictions on increased precipitation whether the articles deal with precipitation as opposed to temperature. (Tr. 256-270)

[8] Over 50% of electricity generation in New England is gas-fired, which is progressively increasing as the region moves away from phosphate fuel sources. It is not surprising that there is a direct correlation between electricity prices and gas prices. (Karstens Report Ex. 18 at 7.)

do not correlate to national prices, then the revenue forecast for the Facility needs to be adjusted to account for higher projected electricity prices.

Mr. Karstens' theory of gas pipeline constraint is interesting, but this Tribunal has concluded that it is not appropriate to consider it. The mandate of this Tribunal is to determine the fair market value of the Facility on April 1, 2013. The Claimant presented no evidence that Mr. Karstens' pipeline constraint theory was information that was disseminated in the market before the valuation date. In fact, the Claimant's own expert valuation witnesses, Mr. Moody and Mr. Sansoucy, testified that they were not aware of Mr. Karstens' theory and, more importantly, did not think that a purchaser would have been aware of his constraint theory. Mr. Moody explains: "We were not aware of it as of the appraisal date. And we are not aware that the purchaser would have been aware of it at that date. We learned of it subsequent to that; so that is why we didn't include it." (Tr. 683.) Mr. Sansoucy likewise indicated that Mr. Karstens' pipeline constraint phenomenon was not known to him as of April 1, 2013, noting that as of that date there was not "any clear vision on how to solve these problems and how to monetize them, so I did not [utilize it]." (Tr. at 901-02.)

Furthermore, the expert valuators used software programs to develop their DCF analysis. Messrs. Moody and Sansoucy and Silver used the Ventyx software and the Respondent's expert, Mr. Peaco, used the Aurora software, each of which makes adjustments for different views on inflation and natural gas/electricity prices. (Ex.

142 and 143). The Claimant has presented no evidence that the hypothetical bidder for the Facility would not use one of the two software programs to value the Facility differently than the Claimant's and Respondent's expert valuators.

Nor was there any evidence presented which would lead this Tribunal to conclude that the Ventyx and Aurora programs did not include pipeline constraint considerations. In fact, the evidence suggests the contrary. Mr. Sansoucy described the Ventyx program the following way:

> ... we buy the model already run for New England, for seven zones, on peak, off peak, all REC zones, the different states. The model has gas pricing in each of the regions; we buy the whole model. We don't do our own model per se; we used and stopped doing that about ten years ago. (Tr. 892-3).
>
> ...it draws down the focus New England and parts of New England. It models gas pricing; it models the dispatch of electric plants in New England marketplace; ... It is a bare-knuckle forecast. There's no messing around with it. (Tr. 793, 901-2).

In addition to the Ventyx program, Mr. Moody used the Energy Information Agency ("EIA") data to develop pricing for the Facilities'. He explained that EIA output projects Henry Hub prices and "transportation costs between Henry Hub and various locations." (Tr. 682). As a result, the transport cost from Henry Hub to New England is included in gas pricing. (Tr. 682).

Having considered the WOP's position on pipeline constraint, the Tribunal does not believe that a prudent potential bidder on April 1, 2013 would have considered Mr. Karstens' pipeline constraint theories in projecting future electricity prices.

(ii) Revenue as a QF Under PURPA

WOP's appraisers submitted DCF valuation models on the assumption that the Facility would be able to renegotiate its expired Power Purchase Agreement ("PPA") and enter into a favorable long-term Avoided Cost PURPA PPA.[9]

WOP maintains that a reasonable buyer looking to purchase the Facility on April 1, 2013 would have assumed that it would be able to negotiate long-term PURPA PPA at an initial avoided cost rate of $65-$70 and increasing over time. WOP bases this theory on three BED wind contracts that were negotiated over the previous four years reflecting an energy rate of $65--$75 per MW/hour (Ex. 66-68). WOP's theory is also supported by testimony from its expert valuators, Messrs. Moody and Sansoucy, who testified that in their respective opinions comparable PURPA contracts nationwide are priced starting at $70 per MW/hour, excluding RECs, and increasing over time (Tr. 686-88, 759-60, 876, 880-81).[10]

WOP makes two fundamental errors in concluding that a reasonable buyer of the Facility would assume that the Facility would be able to secure a long term QF PPA with an escalating $70 per MW/hour price. First, it assumes that over the 20 year period since the expired Winooski One PPA was negotiated Federal and State

[9] Since the expiration of its PURPA contract on March 31, 2013, WOP has been selling the Facility's output on the ISO-New England spot market as a merchant generator.

[10] Compare Moody Merchant rate escalation 2013 at $35.43 escalating in 2028 to $88.08 and QF rate in 2013 $70 and increasing in the same period to $90.55, suggesting a valuation differential of $6,432,000 ($26,446,000-20,014,000).

energy regulations have stagnated. Second, it assumes that Burlington's wind contracts, even if relevant, would determine Vermont's avoided costs rates.

(a) Federal and State Regulatory Developments

Congress passed the Power Utilities Regulatory Policy Act of 1978 ("PURPA") directing the Federal Energy Regulatory Commission ("Commission") to promulgate rules and regulations requiring utilities to offer to purchase electrical energy from qualifying facilities ("QFs") at rates that are just and reasonable, nondiscriminatory, and which do not exceed "the incremental cost to the electric utility of alternative electric energy". Congress directed state regulatory authorities to adopt rules that established general conditions under which utilities are required to purchase power from QFs.

The Vermont Public Service, the State regulatory authority responsible for implementing PURPA, issued Rule 4.100[11] to meet Vermont's obligation under PURPA in 1983. In the last ten years, New England has developed a fully competitive real time wholesale energy and capacity market (ISO New England), (Tr. 1162, 1209, 1589-90.) operating on a real time basis. (Tr. 1589-90.)

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[11] 30 V.S.A. Sec. 209(a)(8)),

In 2005, Congress amended PURPA by modifying the conditions under which electric utilities are obligated to purchase electric energy from QFs.[12] The legislation provides for termination of the requirement that an electric utility enter into new power purchase obligations or contracts to purchase electrical energy from QFs if the Commission finds that QFs have non-discriminatory access to markets. The Commission determined in Order 688 that the markets administered by ISO New England qualified as non-discriminatory. Furthermore, the Commission established a rebuttable presumption that QFs with a net capacity below 20 MWs do not have nondiscriminatory access to markets.

(b) Wind Contracts As Proxy

WOP and its expert valuation witnesses suggested in this proceeding that the three BED wind contracts (Exhibits 66-68) and the Vermont Energy Act of 2009 (Act 45) Standard Offer Program, Sustainability Priced Energy for Economic Development (SPEED) Program would be a good proxy in any avoided cost hearing to be conducted by the Vermont Public Service Board ("Board"). However, the suggestion that the Board would establish avoided costs based on three wind contracts and a Statewide standard offer program for facilities less than 2.2 MW, is not realistic.

[12] Section 210(m) 16 U.S.C. Sec. 824a-3(m) (2006).

The Respondent's witness, Mr. Nolan, explained that the last avoided costs hearing under Rule 4.100, designated as Docket 5177, was contentious and took two and a half years to complete. The hearings started in September 1986 and were not completed until March 1989. Rather than using a few contracts to determine avoided costs, as suggested by WOP, the Board utilized a software program similar to the Aurora program and loaded into the program all of the generation contracts that Vermont utilities had at the time. The Board did a load forecast and ran projections out 25 years. The Commission then assumed that an inevitable gap would develop as some contracts expired and plants were retired and replaced by the construction of new coal plants. Costs associated with the construction and operation of the plants were then inserted in the model, which was used to calculate avoided costs. (Tr.1579-89). Mr. Nolan further testified that the BED wind contracts would be one of a number of PPAs that would be utilized by the Commission, as would any other existing or committed supply resource.

The appropriateness of using the BED wind contracts as a proxy for an avoided cost calculation is further undermined by the fact that the wind contracts have components that have nothing to do with avoided cost calculations—optionality, minimum delivery requirements, liquidated damages, ancillary services, delivery point in Vermont rather than location of plant, credit terms and credit rating among others, all of which have value to BED. (Tr.1596-1599). In addition, each wind contract includes Class I RECs qualified in multiple markets and, as pointed out above, those environmental attributes are not included in Rule 4.100's definition of avoided cost. (Tr. 1602). Professor Dworkin testifying on behalf of WOP concurs with the fact that the wind contracts proposed as a proxy consist of energy, plus capacity, plus RECs, and ancillary services. He also recognized the delivery point makes a difference as does whether it is a Class I or Class II REC. (Tr.436-7).[13]

BED's witness, Mr. Nolan, testified that a prudent bidder for the Facility would be aware of the Department of Public Service's ("Department") position on how the Vermont Public Service Board ("Board") should approach the Claimant's February 15, 2013 petition to the Board to "...open an investigation for the purpose of establishing rates for power sold by qualifying facilities to the Rule 4.100 Purchasing Agent pursuant to Rule 4.104..."(Tr. 1591-92.)

In a letter dated May 24, 2013, the Department, while recognizing the Facilities QF status under FERC, recommended to the Board that it should not follow "outdated" procedures outlined in Rule 4.104(E) last utilized over 20 years ago in a different market which "do not serve the interests of Vermont ratepayers or administrative efficiency". Furthermore, the Department recommended that the Board should not return to generic rate making procedures and instead "...address individual

[13] A fourth wind contract was entered into between BED and NextEra an existing renewable resource for a 5 year term with 5 year rolling options, and represents an energy only purchasing decision on the City's part. Under the NextEra contract BED is purchasing the energy for roughly $50 MW/hour and Class II RECs at 85 cents. (Tr. 1619). Based on the evidence this contract was not utilized by WOP's witnesses Sancousy or Moody (Tr. 706-7) in any of their avoided cost calculations.

avoided cost contracts on a case-by-case basis..." (See Duggan May 24, 2013 Letter Ex. 123).

Even if the hypothetical investor did not make the necessary inquiry at the Department with respect to the position that it would take on future avoided cost proceedings, a prudent investor would know that other regulatory authorities, such as New Hampshire and Connecticut, tied their QF rates to the competitive ISO market.[14]

A reasonable market participant would have known as of April 1, 2013 the following information: the Facility's avoided cost contract had terminated; the last time avoided cost rates were set in 1989, it was a contentious proceeding that took 2 ½ years to resolve; there was great uncertainty as to what avoided cost rates might actually be once established; the energy market in New England had completely changed with the advent of the standard market design in 2003; the Department, charged with proposing avoided cost rates, was advocating a different approach based upon a fully functioning regional market; PURPA was amended in 2005 to allow for the possibility that QFs with non-discriminatory access to markets like ISO-New England could be denied avoided cost rates; the rates that the Public Service Board had most recently established for hydro plants smaller than 5 MW would not be available to the Facility absent a legislative change;

[14] See N.H.P.U.C Order No. 23,449 in Docket No. 00.039 –May 1, 2000; 220 CMR 8.00: M.G.L. c. 25, Sec. 5- c. 164, Sec 76C)

Vermont Energy Act of 2009 (Act 45);[15] neighboring New England states that had more recently addressed the issue had established avoided cost rates based upon the ISO-NE market.

Having reviewed all of the evidence and testimony in this case, the Tribunal concludes that a purchaser on April 1, 2013 would not have assumed that the Facility would qualify for rates in a future avoided cost hearing at a level other than those projected by the ISO-New England market.

C. ENVIRONMENTAL ATTRIBUTES

The Facility is a renewable generator, which qualified on January 1, 2013 (effective November 1, 2012) in the Massachusetts Renewable Portfolio Standard Class II ("MA II") market due to its Low Impact Hydro Institute ("LIHI") certification.[16] It generates MA II renewable energy credits ("MA Class II RECs") for every megawatt-hour of energy production.

The Parties disagree on the long-term value of the MA Class II RECs. WOP's valuation witness, Mr. Moody, projected that MA Class II REC rates would progressively increase from the current $26 in 2013 to $35.39 by 2026 (Moody

[15] Act mandates use of a market-based mechanism to determine pricing for Standard Offer Program facilities supporting the State of Vermont moving away from avoided cost rates.

[16] The Low Impact Hydropower Institute (LIHI) is dedicated to reducing the impacts of hydropower generation through the certification of hydropower projects that have avoided or reduced their environmental impacts pursuant to the LIHI's criteria.

Report Ex. 16--Ex. 2). Mr. Sansoucy projected that MA Class II REC rates would increase two percentage points annually from $24 in 2013 to $32 to 2026. (Sansoucy Report Ex. 20-- App. E). BED's expert, Mr. Peaco, assumed a price trajectory for MA Class II RECs through 2015 close to the current Alternative Compliance Payment ("ACP") rate ($26) that would progressively decline in the period between 2016 and 2018, and further declining to $1 for the remainder of the DCF period. (Peaco Report Ex. Ex 25 P. 12-13). Mr. Silver projected that MA Class II REC prices would increase from $26.68 in 2013 to $27.96 in 2016, falling to $20.00 in 2017 and 2018, to $15.00 between 2019 through 2020, to $5.00 in 2021 and $0 thereafter. (Silver Report Ex. 29).

MA II was established by the Massachusetts Green Communities Act of 2008 ("MGCA") to provide incentives for the continued operation of pre-1998 renewable energy and waste energy plants. ("Renewables") (Ex.61 at 18). A hydroelectric plant qualifies to participate in the program if (i) it produces no more than 7.5 MW (increased from 5 MW on January 1, 2013) and (ii) it is LIHI certified.

The MGCA requires retail electricity suppliers to purchase 3.6% of their energy from Class II renewable energy producers. If retail electricity suppliers fail to meet the statutory minimum purchase obligation by purchasing MA Class II RECs on the open market, they must pay an administrative penalty known as the Alternative Compliance Payment ("ACP") set at $26.79 for 2013. (Sansoucy Report Ex. 20 at 57). The funds collected are held in the Massachusetts Clean Energy Center, which support or promote the development of renewable or other clean energy projects. (RPS Report, See below)

The MGCA program ran into some headwind. A report prepared by the Massachusetts Department of Energy ("DOER"), entitled *Massachusetts RPS & APS Annual Compliance Report for 2011,* dated April 9, 2013, (the "RPS Report"), outlined that in 2011, the availability of MA Class II RECs fell "... far short of the demand." (Exhibit 61.) Only 39 Renewables with a total capacity of 77MW qualified to issue MA Class II RECs. The RPS Report concluded, "[c]onsequently, only twelve [s]uppliers were able to acquire the 236 GWh of available MA Class to II RECs towards meeting the 3.6% obligation totaling 1,643 GWh, while 86% of the obligation were met by ACPs, which totaled about $36 million."[17] Hence only 14% of the MGCA renewable requirement is met by MA Class II RECs. (Tr. 1655).

The imbalance between demand for MA Class II RECs and available supply resulted in pricing of Class II RECs at "around $26" according to WOP's expert, Ms. Butt (Tr. 486), which is very near the ACP payment penalty levels.[18]

The extraordinarily high prices that MA Class II RECs command raises two fundamental problems. First, the MGCA program was developed to encourage the continued operation of pre-1998 renewables by providing a revenue stream toward the costs associated with the facilities' O&M costs. (Tr. 1168). The

[17] RPS Report at 4
[18] ACP payment penalty set for 2013 is $26.79 Sansoucy Report Ex. 20 at 57

unintended consequences of the high MA Class REC II prices resulted in participants like the Winooski One Facility receiving a windfall revenue stream.[19] Secondly, Massachusetts's ratepayers are directly affected by high payments because ultimately they shoulder the burden of high ACP payments.

The problems associated with the MGCA program did not go unnoticed by the Massachusetts Legislature. The DOER was directed to study and recommend regulatory or statutory changes to alleviate the program's reliance on the ACP mechanism. In response, DOER presented a report to the Legislature on December 31, 2012 entitled *Evaluation of the Massachusetts RPS Class II Program* recommending a number of options to the Legislature. (Ex. 4).

The Parties to this arbitration differ on their assessment of the political risk associated with the continuation of the MA Class II REC program in its current form. BED's expert, Mr. Peaco, expressed the view that Massachusetts' legislature will ultimately make fundamental changes to the program because the "contemplated" Class II REC market is "...not a functioning market ...[and] eventually will be reformed in some substantial way" (Tr. 1181). WOP's expert, Ms. Butt testified that Massachusetts is "...supportive of the existing MA Class II REC market...[s]o I do not see them doing away with Massachusetts Class II" and that "...for the next 20 years the market should trade near the Alternative Compliance Payment." (Tr. 494, 528).

[19] Based on Mr. Moody's MA REC II revenue projections, income generated from the Recs would exceed O&M by 2017 (Ex. 156.)

While the Tribunal is less optimistic about the future of Class II RECs than Ms. Butt, it is not necessarily convinced that the REC market in general, and MA Class II RECs in particular, will be replaced by a national carbon tax, a national cap and trade program, the current Regional Greenhouse Gas Initiative, ("RGGI"), or some other initiative not currently in the marketplace. (Tr. 1182, 1193-4).

What will happen to the MA Class II RECs in three to five years is anyone's guess. It may disappear overnight like the biomass Connecticut Class I REC market. (Tr. 1663-68, 1715), or it may continue throughout the DCF period as suggested by Mr. Sansoucy. [20]

On April 1, 2013 an informed investor would not have known the outcome of the MA REC II debate. The revenue stream of the Facility could be dramatically affected by legislative initiatives reducing or eliminating MA Class II RECs. On the other hand, the Facility could reap the benefits of a healthy revenue stream extending well into the future.

The Tribunal believes that Mr. Silver adequately dealt with the uncertainties associated with the future value of MA Class II RECs in his DCF model by providing

[20] Vermont's Comprehensive Energy Plan sets out a pathway to obtain 90% of its energy from all renewable sources by 2050. The plan aims to obtain 20% of its renewable energy from the SPEED Program, along with an established and aggressive renewables program with 75% of all electricity coming from renewable energy sources by 2032. (Exh.156).

an income stream through at least 2021. His model provides the following revenue stream ($/MWh): 2014--$26.28; 2015--$27.96; 2016--$27.96; 2017--$20.00; 2018--$20.00; 2019--$15.00; 2020--$15.00; 2021--$5.00 and $0 thereafter through2029. (Silver Ex. 29, Table X).[21]

II. DISCOUNT ON FMV

The March 27, 2013 Stipulation by the Parties outlining the issues to be determined by this Tribunal raised one additional matter: "[T]he value of a discount if any, on the to-be-determined fair market value of the power plant for the period between April 1, 2013 and the date of the Award" ["Discount"]. While this issue was noted as an outstanding issue of BED, BED did not offer any oral or written presentation on the subject. However, WOP, outlined why the BED should not be entitled to any discount in its Pre-Hearing Brief.

WOP maintains that BED has no rights to a discount because the Option Agreement specifically addresses which party is entitled to interest related relief and under what circumstances. The Option Agreement provides that neither BED nor WOP has any interest related rights for the first 18 months after BED gives WOP notice of its intention to exercise its option.

21 An email dated June 19, 2012 from Jack Velasquez of Marex Spectron, Ms. Butt's supervisor, supports Mr. Silver's opinion that the value of RECs will decline in the future. While Mr. Velasquez describes the strength of the MA Class I market, which was trading in "high $50s", he wrote"…[p]lease note do(sic) to legislative uncertainty most REC forward price do slope downward. In addition buyers are typically unwilling to purchase future vintages near the cap, as it leaves very little upside and plenty of downside risk in the event of a sell off." In fact an attached chart shows a 2012 mid price for MA Class II RECs at $59.38 and a 2020 mid price at $14.00.

The Option Agreement provides that after BED exercises its option "WOP shall continue in possession of its Ownership Share of the Project and associated property until the completion of the closing and transfer to BED." (Par. 8). The Option Agreement further provides that in the event a closing for whatever reason is not consummated within eighteen months from the date of the exercise of the option to the day on which the transaction is consummated, BED is obliged to pay interest to WOP calculated at the Chase Manhattan Bank prime lending rate plus two percentage points. (Par. 9).

The Parties clearly dealt with any payment obligations that would be due after BED's exercise of the option and as such BED is not entitled to a Discount.

FAIR MARKET VALUE OF THE FACITY

Having reviewed the Parties' briefs and arguments and having considered all of the evidence in this case, including the testimony of the Parties' witnesses and the exhibits admitted into evidence, having considered the competence of the expert witnesses and the reliability of their testimony and exhibits, and having considered the weight to be given to all evidence, the Tribunal concludes that the fair market value of the Facility as at April 1, 2013 was $16,000,000.

AWARD

For reasons stated above, the Tribunal hereby AWARDS as follows:

1. The fair market value of the Winooski One Hydro Facility located on the Winooski River in Burlington, Vermont as at April 1, 2013 was $16,000,000.

2. In the event Burlington exercises its right to acquire the Facility pursuant to the Terms of the Option Agreement, it is not entitled to a discount on the value of the Facility from April 1, 2013 to the date of this Award.

3. All other claims and counterclaims not specifically addressed herein are denied.

4. Pursuant to a stipulation between the Parties, the fees, expenses and arbitrator compensation are to be borne equally by the Parties. Accordingly, the administration fees of the AAA, totaling $19,495 and the fees and expenses of the arbitrators totaling $364,068.18 shall be borne equally by the Parties. BED shall reimburse WOP the sum of $9,747.52 representing that portion of said fees and expenses in excess of the apportioned cost previously incurred by WOP.

This Final Award of the arbitrators may be executed in any number of counterparts, each of which shall be deemed an original, and all of which shall constitute together one and the same instrument.

We hereby certify that this Final Award of Arbitrators was made in Burlington, Vermont.

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Dated: December 10, 2013

Henry J. Fieldman

Henry J. Fieldman

Dated: December 10, 2013

Steven A. Shapiro

Steven A. Shapiro

Dated: December 10, 2013

George Gluck, Panel Chair

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