REDACTED

SANSOUCY
ASSOCIATES

Appraisal Report as of April 1, 2023

Comerford and McIndoe Hydroelectric Developments

Town of Monroe, NH

Owned By:
Great River Hydro, LLC

REDACTED

PRIVILEGED AND CONFIDENTIAL

Sansoucy Associates
148 Main Street | Lancaster, NH 03584
101 Gulliver Street | Fountain Inn, SC 29644

Photo Source:
greatriverhydro.com

SANSOUCY
ASSOCIATES
Complex Utility and Property Valuation, and Regulatory Consulting

REDACTED

December 29, 2023

via email
{*monroeselectmen@monroenh.org*}

Board of Selectmen
Ms. Diane Gibson Smith
Town of Monroe
P.O. Box 63
Monroe, NH 03771

RE: Appraisal Report of Comerford and McIndoe Hydroelectric Developments, owned by Great River Hydro, LLC, located in the Town of Monroe, NH as of April 1, 2023:

Dear Board of Selectmen,

Pursuant to your request, please find attached an appraisal report setting forth the *"as is"* retrospective market value of the real and personal property owned by the above listed owner(s) in the Town of Monroe, NH. This report is intended to comply with the purpose and reporting requirements set forth by the 2020/2021 Edition (Extended to December 31, 2023) of the *Uniform Standards of Professional Appraisal Practice* (USPAP) for an appraisal report. This report presents a summary discussion of data, reasoning, and analyses that were considered and utilized in the appraisal process to develop the conclusion of value. Additional documentation and information have been retained in our work files. The extent to which information and conclusions are presented in this report is consistent with the needs of the intended users and use of the appraisal. This appraisal was prepared to express the *"as is"* retrospective opinion of market value for the subjects of this report.

The enclosed report describes the properties that are the subject of this report, the data gathered, and the valuation approaches used in the preparation of this appraisal. As a result of our investigation and analysis of the information gathered, the estimated *"as is"* retrospective market value of the properties owned by the above listed owner in the Town of Monroe, NH as of April 1, 2023, is:

	A		B		C
Row	Description		Comerford		McIndoe
1	**Valuation Summary**				
2	Reconciled Market Value:		$264,000,000		$23,700,000
3	*less: Total Land Monroe, NH*		*$1,151,700*		*$421,100*
4	*less: Total Land Barnet, VT*		*$4,347,400*		*$1,225,400*
5	***Subtotal Property Improvements:***		***$258,500,900***		***$22,053,500***
6	***Allocation to Barnet, VT***				
7	Percent Allocation	*17.5%*		*11.4%*	
8	***Total Taxable Improvements:***		***$45,237,658***		***$2,514,099***
9	***Allocation to Monroe, NH***				
10	Percent Allocation	*82.5%*		*88.6%*	
11	***Total Taxable Improvements:***		***$213,263,243***		***$19,539,401***
12	*Plus: Land - Monroe, NH*		*$1,151,700*		*$421,100*
13	***Total Taxable Value - Monroe, NH (rounded):***		***$214,414,900***		***$19,960,500***

This transmittal letter is intended to be relied upon only if it is accompanied by the attached report. The reconciled value indicated above provides our opinion of fair market value, but to understand the process of developing and reconciling this value opinion, it is necessary to read and understand the report and its supporting documentation, if any is provided. Pursuant to USPAP's record keeping requirement, we have retained all our work papers, calculations, research, cost trends, costing work sheets, comparable sales data, income approach worksheets, etc. in our files at 148 Main Street, Lancaster, New Hampshire.

We hereby certify that we have taken into consideration all the factors which are felt to be pertinent to the final value estimate, and that we have not knowingly or intentionally omitted any important data.

If you have any questions, please do not hesitate to contact us.

Sincerely,

SANSOUCY ASSOCIATES

George Sansoucy

George E. Sansoucy, P.E. (NH)
NHCG – 774
NH DRA Certified Property Assessor Supervisor

SA/mks
Enclosures

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LIST OF ACROYNMS

13th Edition	The Appraisal of Real Estate, 13th Edition
14th Edition	The Appraisal of Real Estate, 14th Edition
A&G	Administrative and General
ACP	Alternate Compliance Payment
AFUDC	Allowance for Funds During Construction
CAMA	Computer Assistance Mass Appraisal
CapEx	Capital Expense
CEII	Critical Energy Infrastructure Information
CELT	Capacity, Energy, Loads and Transmission
CFS/cfs	Cubic Feet per Second
CIAC	Contribution In Aid of Construction
CPI	Consumer Price Index
CPR	Continuing Property Records
CT	Connecticut (River)
CWIP	Construction Work In Progress
DAM	Day-Ahead Market
DCF	Discounted Cash Flow
EBITDA	Earnings Before Interest Taxes Depreciation and Amortization
ECAR	East Central Area Coordination
EIA	Energy Information Administration
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
GAAP	Generally Accepted Accounting Practices
GW	Gigawatt
HWI	Handy-Whitman Index of Public Utility Construction Costs
IDC	Interest During Construction
IOU	Investor-Owned Utility
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
kW	Kilowatt
kWh	Kilowatt-hour
kWh-yr.	Kilowatt-hour per Year
LIHI	Low Impact Hydro Institute

LLC	Limited Liability Company
LMP	Locational Marginal Price
LMP	Locational Marginal Pricing
MACC	Mid-Atlantic Area Council
MAIN	Mid-American Interconnected Network
MSL	Mean Sea Level
MVS	Marshall Valuation Services
MW	Megawatt
MWh	Megawatt-hour
MWh-yr.	Megawatt-hour per Year
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
O&M	Operating & Maintenance
PPA	Power Purchase Agreement
PUC	Public Utilities Commission
PV	Present Value
RCN	Reproduction/Replacement Cost New
RCNLD	Reproduction/Replacement Cost New Less Depreciation
REC	Renewable Energy Certificate
RFP	Request for Proposal
ROE	Return On Equity
RPS	Regional Portfolio Standards
RS Means	The R.S. Means Historical Cost Index
RTM	Real-Time Market
SBA	Small Business Administration
SEC	Securities and Exchange Commission
SEDAR	Canadian System for Electronic Document Analysis and Retrieval
SMD	Standard Market Design
SNCR	Selective Non-Catalytic Reduction
TCPM	TransCanada Power Marketing
USBR	U.S. Bureau of Reclamation Cost Index
USGS	United States Geological Service
USPAP	*Uniform Standard of Professional Appraisal Practice*
VTPUC	Vermont Public Utility Commission
WACC	Weighted Average Cost of Capital

PROBLEM IDENTIFICATION & OPINION OF VALUE

Type of Report:

Revaluation Appraisal Report

Client Identification:

Town of Monroe, New Hampshire (Town)

Intended Use and User:

The intended use of the report is to provide an "as is" retrospective opinion of market value for *ad valorem* tax purposes as of the valuation date of April 1, 2023. The intended user(s) of this report is the Town of Monroe, and the Monroe Board of Selectmen.

Problem Identified:

The problem to be solved is the estimation of an "as is" retrospective opinion of market value for the fee simple interest in the subject property located in the Town of Monroe, NH based on market conditions that existed on the valuation date of April 1, 2023, which can be used by the intended user(s) of this report for the previously stated purpose.

The assignment elements, market analysis, property description, and the valuation analysis presented in this report outline the nature of the problem and identify the key market conditions that derive the value of the Developments. The Developments are considered special purpose property and thus are subjected to very unique market forces compared with traditional real property such as residential or commercial, which are further discussed below.

Property Name and Location:

Comerford Hydroelectric Station & McIndoe Hydroelectric Station (collectively referred as the Developments) are part of the Fifteen Mile Falls Project – FERC Project No. 2077 and are located on the Connecticut River in the Towns of Monroe, NH and Barnet, VT.

Ownership:

Great River Hydro, LLC (Owner), a subsidiary of Hydro-Quebec.

Interest and Property Rights Appraised:

The property right appraised is the fee simple estate which includes all the certificates, privileges, permits, licenses, rights, consents, and grants utilized in owning and operating the subject property of this appraisal.

Date of Valuation, Date of Site Inspection, and Date of Report:

Date of Valuation (Effective Date): April 1, 2023

Date of Site Inspection: June 4, 2021, and September 23, 2022

Date of Appraisal Report: December 29, 2023

The USPAP edition applicable to this appraisal is USPAP 2020-2021 (Extended to December 31, 2023).

Value Type:

Fair Market Value

Indicated Value:

	A	B	C
Row	**Description**	**Comerford**	**McIndoe**
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13	***Total Taxable Value - Monroe, NH (rounded):***	***$214,414,900***	***$19,960,500***

Property Type:

Hydroelectric Generating Stations

Property Description:

See Report

Project Operating Data:

The Fifteen Mile Falls Project is operated as both storage and release and run-of-river, depending on the need and available river flows. The 11-year (2012-2022) average historic generation for the Developments are as follows:

- Comerford Station: **340,355 MWh**
- McIndoe Station: **43,617 MWh**

Property Use Presently and Property Use in Appraisal:

Property Use Presently: Hydroelectric generating facility

Property Use in Appraisal: Hydroelectric generating facility

Tax Parcel Identifier:

Monroe, NH Parcel ID(s): Parcel|000-007 (improvements only), Parcel|R04-003 (1.1-acres), Parcel|R04-004 (13-acres), Parcel|R08-006 (38.2-acres), Parcel|R08-007 (10-acres), Parcel|R08-008 (65-acres), Parcel|R11-011 (86-acres)*, Parcel|R11-012 (81-acres), Parcel|R11-013 (5-acres), Parcel|R11-014 (94.6-acres), Parcel|R11-022 (28-acres), Parcel|R11-023 (14-acres), Parcel|U02-048 (17.3-acres), Parcel|U03-008 (0.147-acres), Parcel|U03-009 (5.2-acres), Parcel|U03-010 (1.3-acres), Parcel|U03-011 (0.15-acres), Parcel|U03-012 (0.33-acres), and Parcel|U03-013 (20.58-acres)

**Great River Hydro Parcel |R11-011 total acres equal 86. Ten acres of this parcel are accounted for on New England Power Company Parcel|R11-011-00A.*

Zoning:

The Developments are located in a variety of zoning jurisdictions in Monroe, New Hampshire, and Barnet, Vermont located along the Connecticut River. In most cases, the Developments are non-conforming uses which pre-date the existence of zoning in the various towns. Therefore, the Developments' non-conforming uses are considered typical. In addition, electrical generating facilities are typically permitted by FERC, or by the Vermont and/or New Hampshire Energy Facility Siting Processes.

USPAP ASSIGNMENT CONDITIONS & ELEMENETS

Purpose of Assignment:

The purpose of the assignment is to express an "as is" retrospective opinion of fair market value for the property as of April 1, 2023.

Definition of Fair Market Value:

The definition of market value used is derived from NH RSA 75:1, which defines market value as:

> "Market value means the property's full and true value as the same would be appraised in payment of a just debt due from a solvent debtor."

Our conclusions of market value as provided herein conforms to NH DRA REV 601.32, which defines market value as follows:

a) Is the most probable price, not the highest, lowest, or average price;
b) Is expressed in terms of money;
c) Implies a reasonable time for exposure to the market;
d) Implies that both buyer and seller are informed of the uses to which the property may be put;
e) Assumes an arm's length transaction in the open market;
f) Assumes a willing buyer and a willing seller, with no advantage of being taken by either buyer or seller; and
g) Recognizes both the present use and the potential use of the property. Ther term includes "full and true value."

Scope of Appraisal and Work:

The scope of our services in this assignment included the research and analyses necessary to identify the appraisal problem to be solved and undertake the research and analyses necessary to develop credible assignment results. The following provides a summary of our problem identification, research, and analyses of the physical and economic characteristics of the subject property, and the standard appraisal techniques employed to arrive at our opinion.

Extent of Investigation:

In preparing this appraisal and providing our estimate of value, we employed commonly accepted appraisal techniques and procedures. This included a review of facts and data associated with the subject property, which was generally performed by George E. Sansoucy, P.E (NH) and staff. In addition, the following factors were considered with respect to the subject property.

- History and nature of the electric industry including potential expansions in the region;
- Physical characteristics, condition, and utility of the property;
- Historic, existing, and future use of the property;

- Analysis of subject property's capacity and utilization;
- Economic demand for the subject or its utility including historic and future cash flow potential;
- General economic and market conditions for the property;
- Identification and analysis of sales considered comparable to the subject;
- Documentation, maps, and plans provided by the Owner;
- Federal Energy Regulatory Commission documents and filings;
- US Energy Information Administration documents and filings;
- ISO-New England publications;
- Handy-Whitman Index and RSMeans cost estimators;
- Value Line Investment Survey;
- Various industry and market publications and articles;
- Documents, files, maps, and plans held in the appraiser's files.
- Information available in the public domain;
- Other lesser factors; and
- Site visit by George Sansoucy on June 4, 2021, and September 23, 2022.

The information gathered and analyzed in estimating the market value of the subject included information collected by the appraiser as well as information provided by the owner and in the public domain. This information is cited in this report where necessary to allow the intended user(s) to understand the source and relevance of this information.

Appraisal Process:

In developing this appraisal and estimate of value, all three traditional approaches to value were considered which include the cost, sales comparison, and income capitalization approaches. The applicability and development of each approach is set forth in this report along with the reconciliation to a single value estimate.

Update of Prior Appraisals:

This appraisal report is performed under a new assignment and does not update any prior appraisals.

Extraordinary Assumptions:

An extraordinary assumption implies that if the assumption was found to be false, the opinion of value could be altered. The following extraordinary assumptions were employed:

- Fair market value of certain parcels of land owned in fee by the Owner of the subject property(ies) are those values set by the Municipalities' assessor using the Municipalities' CAMA system. For this report, we make the extraordinary assumption that the CAMA system value developed by the Municipality represents fair market value.
- We have assumed, for this report, that the subject(s) are in good working order and its condition and reliability are consistent with its claimed capability reported to the NH and VT PUC, ISO-NE, and FERC.

Hypothetical Conditions:

A hypothetical condition is that which is contrary to what exists but is supposed for the purpose of the analysis. Hypothetical conditions were not employed in the valuation of the subject(s).

Jurisdictional Exceptions:

A jurisdictional exception is an assignment condition that voids the force of a part or parts of the *Uniform Standards of Professional Appraisal Practice* (USPAP) when compliance with a part or parts of USPAP is contrary to law or public policy applicable to the assignment. The jurisdictional exception rule was not employed in this assignment.

Sales History of the Subject Property:

The Developments were sold to Hydro-Quebec as part of a transaction which included the total hydroelectric assets of Great River Hydro NE, LLC in September 2022 for a total consideration of $2.25 billion. This sale is discussed in the Sales Comparison section of this report.

Exposure/Marketing Time:

Current appraisal guidelines require an estimate of reasonable exposure time linked to the value opinion. The reasonable exposure time is presumed to precede the effective date of the appraisal. Exposure time is typically defined as the length of time a property interest being appraised would have been offered on the market prior to the hypothetical consummation of a sale at market value on the effective date of the appraisal.

The exposure time in this assignment is assumed to be approximately one to two years and is based on our experience with similar types of properties and discussions with market participants.

Highest and Best Use:

Highest and best use may be defined as the reasonably probable and legal use of the vacant land or an improved property that is physically possible, appropriately supported, financially feasible, and that results in the highest value. The four criteria that the highest and best use must meet are: legal permissibility, physical possibility, financial feasibility, and production of maximum profitability. These criteria are usually considered sequentially; for example, a use may be physically possible, but this criterion is irrelevant if it is not feasible or is legally prohibited.

The definition of highest and best use applies specifically to the highest and best use of the land and/or property. It is to be recognized that in cases where a site has existing improvements on it, it may be concluded that the highest and best use may very well be different from the existing use. The existing use will continue, however, unless and until the value in its highest and best use exceeds the total value of the property in its existing use.

Highest and Best Use as Vacant

The land which consists of and supports the Comerford development (180.9± MW) and McIndoe development (10.5± MW) are currently improved with hydroelectric developments which are licensed by FERC and located on land that is categorized for the purpose of this report as project boundary land. The project boundary land is essential to the operation of the Developments due to its proximity to the Connecticut River and to the impoundment and discharge areas of each Development.

The removal of these improvements would require both FERC and ISO-NE approval based upon a determination that the improvements were no longer required for electric system reliability and/or economic reasons. Therefore, it may not be legally possible to utilize the sites as though vacant. In addition to the legal requirements to make the sites vacant, a review of the subjects' land values indicates that the sites as improved exceed the value of the sites as vacant. However, if it were possible to make the sites vacant, the highest and best use would be as sites for a hydroelectric facility held for future use due to the unique characteristics of the sites and limited number of locations which could be put to a similar use.

Highest and Best Use as Improved

As stated previously, the subject(s) sites are improved with hydroelectric developments. This use is considered to be both legally permissible and physically possible. A review of the Subject(s) operating information and our income analysis indicate that they also generate a positive cash flow and are therefore financially feasible.

The Developments are operated pursuant to the FERC license which dictates the operational characteristics and limit of water that can be impounded for future use. Therefore, the Developments' existing operations are considered to be at or near maximum productivity and profitability. No additional or alternative operating methods, modifications, or additions to the site are considered possible, which would result in greater productivity of the existing site(s) or improvements as of the valuation dates.

Individual Contributions:

The following individuals have contributed appraisal support to the signer of this report:

Matthew Sansoucy, P.E.(SC), CGA (NH-1074), has provided technical support, support in developing the three methods of value, and report preparation for this assignment.

Competency Statement:

The appraiser has experience in valuing property of similar size, type, complexity, and geographic location. Therefore, no professional assistance or steps were required to meet the competency rules of USPAP.

Certification:

See End of Report

Assumptions and Limiting Conditions:

1. Acceptance and/or use of this report constitutes full acceptance of the Assumptions and Limiting Conditions and special assumptions set forth in this report. It is the responsibility of the client or its' designees to read in full, comprehend, and thus become aware of the Assumptions and Limiting Conditions. We assume no responsibility for any situation arising out of a failure to become familiar with and understand the report.

2. Unless otherwise specifically noted in the body of the report, it is assumed that title to the subject property or properties appraised is clear and marketable and that there are no matters or exceptions to title, either recorded or unrecorded, that would adversely affect marketability or market value of the subject property. We are not aware of, nor have we been advised of, any title defects other than those defects that are specifically described in the report. We have not examined title and make no representations relative to the condition thereof. Additionally, other than those specifically noted in the report, we have not reviewed documents regarding liens, encumbrances, easements, deed restrictions, and other conditions that may affect the quality of title. Insurance against financial loss resulting in claims that may arise out of defects in the subject property's title should be sought from a qualified title company that issues or insures title to real property.

3. Unless otherwise specifically noted in the body of this report, it is assumed~~:~~ that the existing improvements on the subject property or properties are structurally sound, seismically safe and code conforming; that all building systems (mechanical/electrical, HVAC, elevator, plumbing, etc.) are in good working order with no major deferred maintenance or repair required; that the roof and exterior are in good condition and free from intrusion by the elements; that the structures/improvements have been engineered in such a manner that they, as currently constituted, conform to all applicable local, state, and federal building codes and ordinances. We have not been retained, in connection with this appraisal assignment, as an independent structural, mechanical, electrical, or civil engineer to perform engineering analyses on the condition of the subject property above and beyond our observations, data analysis, and experience regarding the relative condition of the improvements, which are necessary to develop an opinion of value for the appraisal. Unless otherwise specifically noted in the body of the report, no problems, either physical or functional, were brought to our attention by our client, the intended users of this report, the subject property's ownership or management, etc. It is specifically assumed that any knowledgeable and prudent purchaser would, as a precondition to closing a sale, obtain a satisfactory engineering report relative to the structural integrity of the property and the integrity of building systems. Structural problems and/or building system problems may not be visually detectable. If engineering reports exist, or are developed in the future, which indicate negative factors relative to the condition of improvements/structures such information could have a substantial negative impact on the conclusions reported in this appraisal. Accordingly, if negative findings are reported, we reserve the right to amend our appraisal conclusions.

4. Unless otherwise specifically stated in this report, we have not observed, and we have no knowledge of the existence of hazardous material, which may or may not be present on, or in, the property~~.~~ The presence of substances such as asbestos, urea formaldehyde foam insulation, contaminated groundwater, or other potentially hazardous materials may affect the value of the property. The value estimate is predicated on the assumption that there is no such material on, or in, the property that would cause a loss in value. If the client desires, or requires, an expert opinion as to the existence of hazardous materials on, or in, the subject property, the client is urged to retain an expert in this field. We are not hazardous materials experts, and we assume no responsibility for identifying, quantifying, or providing any advice to the client or any other party as to the existence of hazardous materials that may or may not be associated with the subject property.

5. Unless otherwise specifically stated in this report, no intangible property such as cash, receivables, working capital, prepaid expenses, royalties, patents, workforce valuation, trademarks or goodwill, which are not typically considered as real property, has been considered in the report. To the extent that personal property, as defined by individual states, and real property as defined by individual states, or any combination thereof, is specifically included in this report as tangible property for valuation based on the laws and regulations in effect as of the appraisal date.
6. Unless otherwise specifically stated in this report, it is assumed that all data furnished by the client, property owner, owner's representative, or persons designated by the client or owner to supply said data are accurate and correct. Any material error, which may be present in data or information provided to us could have a substantial impact on our assignment results and conclusions. Thus, if we are made aware of any such error, we reserve the right to amend our assignment results and conclusions reported in the report.
7. Unless otherwise noted in the body of the report, it is assumed that there are no mineral deposit or subsurface rights of value involved in this appraisal, whether they be gas, liquid, or solid. Nor are the rights associated with extraction or exploration of such elements considered unless otherwise stated in this appraisal report. Unless otherwise stated it is also assumed that there are no air or development rights of value that may be transferred.
8. Unless otherwise specifically stated in this report, we are not aware of any contemplated public initiatives, governmental development controls, or additional regulatory controls that would significantly affect the value of the subject.
9. The estimate of market value, which may be stated within the body of this report, is subject to change with market fluctuations over time. Market value is highly related to exposure, time promotion, effort, terms, motivation, and conclusions surrounding the offering. The value estimate(s) considers the productivity and relative attractiveness of the property, both physically and economically, on the open market.
10. Projections of income, expenses, and economic conditions utilized in this report are not predictions of the future, but rather they are estimates of current market expectations for future income and expenses. The achievement of the financial projections will be affected by fluctuating economic conditions and is dependent upon other future occurrences that cannot be assured. Actual results may vary from the projections considered herein.
11. Unless otherwise specifically stated in this report, it is assumed that all required licenses, certificates of occupancy, consents, or other legislative or administrative authority from any local, state, national government, or private entity or organization have been or can be obtained or renewed for any use on which the value estimates contained in this report is based.
12. We have identified our client and any intended users of this report in the body of the report. No other party, other than the client, is a party to the appraiser-client relationship for this assignment. Any person who receives a copy of this appraisal report as a consequence of disclosure requirements that apply to our client, does not become an intended user of the report unless the client had specifically identified them at the time we accepted the assignment.

13. We have identified the intended use of this appraisal in the body of the report. The scope of work for this assignment is based, in part, on the intended use of the appraisal, therefore any use of this report for any other purpose will invalidate its results.

14. This appraisal report, its attachments, and/or addenda may not be duplicated in whole or in part without the specific written consent of the appraiser nor may this report or copies hereof be transmitted to third parties without said consent, which consent the appraiser reserves the right to deny. Exempt from this restriction is duplication for the internal use of the client and its' designees. Also exempt from this restriction is transmission of the report to any court, governmental authority, or regulatory agency having jurisdiction over the party/parties for whom this appraisal was prepared, provided that this report and/or its contents shall not be published, in whole or in part, in any public document without the express written consent of the appraiser, which consent the appraiser reserves the right to deny.

    This report shall not be advertised to the public or otherwise used to induce a third party to purchase the property or to make a "sale" or "offer for sale" of any "security", as such terms are defined and used in the Securities Act of 1933, as amended. Any third party, not covered by the exemptions herein, who may possess this report, is advised that they should rely on their own independently secured advice for any decision in connection with this property. The appraiser shall have no accountability or responsibility to any such third party.

15. Any value estimate provided in the report applies to the subject property as described, and any pro ration or division of the title of that property into fractional interests will invalidate the value estimate, unless such pro ration or division of interests has been set forth in the report.

16. Any allocation of the total valuation in this report between land and improvements applies only under the highest and best use as identified in the report. Component values for land and/or buildings are not intended to be used in conjunction with any other property or appraisal and are invalid if so used.

17. The maps, plats, sketches, graphs, photographs and exhibits included in this report are for illustration purposes only and are to be utilized only to assist in visualizing matters discussed within this report. Except as specifically stated, data relative to size or area of the subject and comparable properties has been obtained from sources deemed accurate and reliable.

18. It is assumed that the subject property is, or will be, under prudent and competent management and ownership, and is neither inefficient nor super-efficient.

19. It is assumed that the subject property is in full compliance with all applicable federal, state, and local environmental regulations and laws unless noncompliance is stated, defined, and considered in the appraisal report.

20. No survey of the boundaries of the subject property was undertaken. All acreage, area~~s~~ measurements and dimensions furnished are presumed to be correct.

21. The Americans with Disabilities Act (ADA) became effective January 26, 1992. Notwithstanding any discussion of possible readily achievable barrier removal construction items in this report, the appraiser has not made a specific compliance survey

and analysis of this property to determine whether it is in conformance with the various detailed requirements of the ADA. It is possible that a compliance survey of the property, together with a detailed analysis of the requirements of the ADA, could reveal that the property is not in compliance with one or more of the requirements of the ADA. If so, this fact could have a negative effect on the value estimated herein. Since the appraiser has no specific information relating to this issue, the effect of any possible non-compliance with the requirements of the ADA was not considered in estimating the value of the subject property.

APPRAISAL OVERVIEW

Introduction

This appraisal report was prepared by Sansoucy Associates and presents the opinion of value regarding the properties referred to as the Comerford and McIndoe developments (collectively referred as the Developments) owned by Great River Hydro, LLC (GRH or Owner) located on the Connecticut River in the Towns of Monroe, NH and Barnet, VT. The Developments are a part of three stations that compose the Fifteen Mile Project (FERC Project No. 2077): Moore, Comerford, and McIndoe. Depending on the need and available river flows, both Comerford and McIndoe may operate as either a storage–release or as a run-of-river hydro. The most recent license for the Fifteen Mile Falls Project was issued by FERC on April 8, 2002, and expires on March 31, 2042. The Town of Monroe is our client and has retained Sansoucy Associates to prepare an appraisal report setting forth our estimate of market value for the Comerford and McIndoe Hydroelectric Developments as of April 1, 2023.

In developing this appraisal and estimate of value, all three traditional approaches to value were considered. These include the cost, sales comparison, and income capitalization approaches, which were reconciled into a final estimate of market value for the Developments. The applicability and development of each approach is set forth in this report along with the reconciliation to a single value estimate.

Separation/Allocation of Comerford and McIndoe Assets

Comerford and McIndoe, like GRH's other hydros on the Connecticut River, are unique in that they are physically situated within two states, and in multiple communities in those two states. Because of this, the appraisal of the Developments requires consideration of the effects of its location in multiple states and municipalities. Among these considerations are the property tax rates in each property tax jurisdiction, state laws regarding the taxation of lands that are subject to conservation easements, and the portion of the physical improvements that are located in each jurisdiction. Our assignment for this report is to appraise GRH's interest in Comerford and McIndoe in the Town of Monroe, NH, which requires an allocation of the overall plants between all of the jurisdictions in which they are located.

In 2013, we undertook a separation study that focused on breaking out all the improvements of the Developments. In this study we concluded that the percentage of the improvements, including the dam, site work, reservoir construction, powerhouse, taxable equipment such as turbines and generators, and all other improvements that are owned by GRH for the Developments. The results of the allocation study are as follows:

<u>Comerford Station</u>

- New Hampshire: 82.5 % of Improvements
- Vermont: 17.5% of Improvements

McIndoe Station

- New Hampshire: 88.6% of Improvements
- Vermont: 11.4% of Improvements

These allocations were agreed upon by the Company and Towns and utilized by the Courts in the TransCanada property tax appeal litigation.

REGIONAL DESCRIPTION

County Description

The Town of Monroe, NH is located in Grafton County, which is located in the upper west central region of New Hampshire and is bordered by the Connecticut River and Vermont to the West. Grafton is the second-largest county in New Hampshire. As of the 2020 census, Grafton County's population was 91,118.[1] The total area of Grafton County is 1,750 square miles, of which 1,709 square miles is land and 41 square miles is water. Figure 1 depicts Grafton County in red.

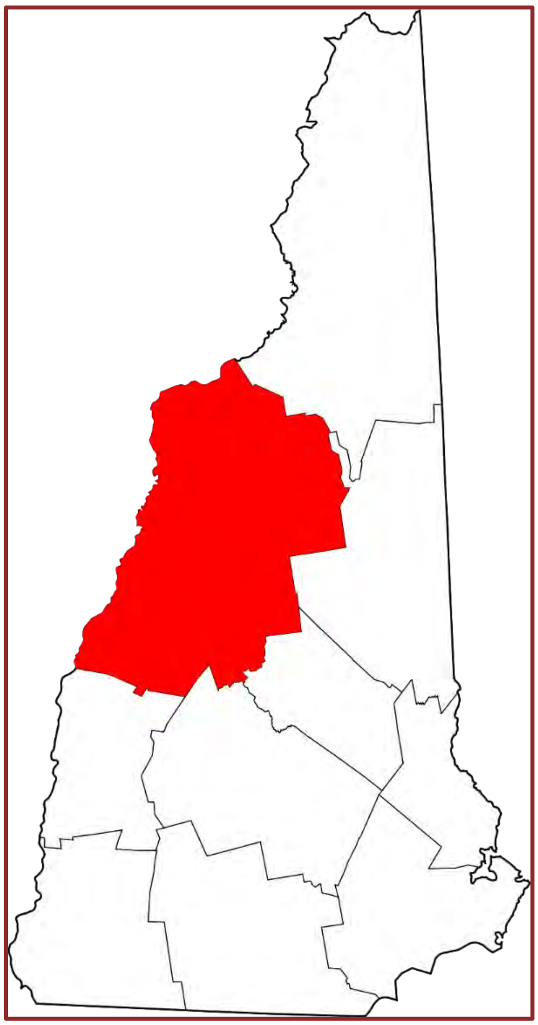

Figure 1: Grafton County, NH

[1] United States Census Bureau

Town Description

Monroe is located in the northwest region on the Vermont/New Hampshire border and is framed by the towns in New Hampshire: Bath to the south, Lyman to the east, and Littleton to the north; and in Vermont by: Waterford to the north, Barnet to the west, and Ryegate to the south.

Figure 2: Town of Monroe, NH[2]

[2] NHES New Hampshire Employment Security – Economic and Labor Market Information Bureau | Community Profiles Monroe, NH

PROPERTY DESCRIPTION

Introduction

The Connecticut River originates near the Canadian border and flows to the Long Island Sound for approximately 407 miles, encompassing a total drainage are of 11,250 square miles.[3] Twelve major hydropower projects currently exist on the river, beginning with the Canaan Project near the headwaters and Connecticut Lakes, and ending with the Holyoke Project. Overall, the Connecticut River's total elevation change is nearly 2,700'.

Figure 3: Connecticut River Basin and Dams[4]

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[3] Great River Hydro Wilder Project, Pre-Application Document 3-1
[4] Great River Hydro Pre-Application Document "Project and Upper Connecticut River Basin" 3-2

Generally, the western banks of the Connecticut River serve as the border between the states of Vermont and New Hampshire. The border was officially established by order of the United States Supreme Court in a ruling that resulted from a lawsuit brought by the State of Vermont against New Hampshire in 1933. The court ruled that a survey would be done, and markers would be placed that would locate the Vermont/New Hampshire boundary at the CT River's original high-water mark as designated by an 1897 marker located in Vernon, Vermont. The survey was completed in 1936 by Samuel S. Gannett and his report was filed with the Supreme Court. The markers that Mr. Gannett placed are essential in the valuation of any property that is located on the CT River because they delineate which part of a property lies in Vermont and which part lies in New Hampshire. Hydroelectric facilities that existed in 1936 were the locations of some of the Supreme Court markers that were installed on the actual border. In areas where there were no structures in the river, monuments were installed on the Vermont side of the CT River indicating, by triangulation, the actual location of the border.[5]

The CT River has and continues to have a very significant impact on the economies, agriculture, recreation, and the character of both states. It had been utilized as a major transportation corridor for over two hundred years, providing a conduit for the delivery of local products such as timber and agricultural goods. The CT River also provided a reliable power source for industry along the CT River from Beecher Falls, Vermont to the Massachusetts border. These industries included paper mills, furniture factories, shoe and garment factories, grain mills, and machine and tool companies. The CT River began to be utilized to produce electricity at the turn of the twentieth century when a small station was built in Stratford, New Hampshire for the production of electricity for the local area. The Vernon Projects' plans and construction commenced around 1905 and the facility went online in 1909. Several other stations were constructed on the CT River until the final major project, Moore Development was built and went online in 1957. Construction of the Comerford and McIndoe stations were completed and began commercial operation in the early 1930's.

Site Descriptions

The Developments are part of the Fifteen Mile Falls Project – FERC Project No. P-2077 located on the Connecticut River in Monroe, New Hampshire and Barnet, Vermont. The Developments are subject to the requirements imposed by the license issued by the FERC. The license, issued on April 8, 2002, encompasses the entire Fifteen Mile Falls Project sites and all of the improvements and dictates the mode of operation, flow of water through the facilities, and use of the sites and improvements. The FERC license expires on March 31, 2042.

The Fifteen Mile Falls Project spans approximately 26-miles and is composed of three developments and three reservoirs. The Project has a total installed capacity of 333.2 MW spread between the three developments, all being remotely controlled from the Renewable Operations Center in Wilder, VT. The Moore Development, located at river mile (RM) 283, is the first upstream development and consists of an 11-mile-long reservoir with a designed head of 150 feet. It's four Francis type turbine-generator units along with a fifth brushless synchronous generator yield a plant generator capacity of 159.5 ± MW. The next two developments that are the subjects of this report are described below.[6]

[5] Supreme Court of the United States, October Term, 1936, The State of Vermont vs. The State of New Hampshire; Report of the Special Commissioner, Samuel S. Gannett
[6] Low Impact Hydropower Institute – Fifteen Mile Falls (LIHI Cert. # 39) Recertification Application January 2022 | Page 6 - 12

Comerford Development

The Comerford Development is located at RM 275 and has a total plant generator capacity of 167.8± MW with a summer capacity rating of 165.9± MW. The Development began commercial operation in 1930 after two years of construction in a monumental ceremony when President Herbert Hoover pressed the button that sent an electrical impulse over a 700-mile circuit opening the turbine gates and set the generators in motion, thus placing a monumental mark in history of the electrical development and progression of the time-period. The development was named after the president of the New England Power Association, Frank D. Comerford.[7]

The Comerford Development is a seasonal storage development operated as a peaking facility due to its upstream connection with the Moore Development and its methods of operation. The development consists of: a 7-mile-long reservoir with a surface area of 1,093 acres and 32,270 acre-feet of gross storage at the normal maximum operating level of 650 feet msl and a minimum operating level of 624 feet msl; a roll-fill earth and concrete gravity dam 170 feet high and 2,253 feet in length; an 850-foot-long concrete spillway with six 7-foot-wide by 9-foot-high sluice gates, four bays of 8-foot-high flashboards and seven 10-foot-high stanchion bays; four steel penstocks each 150 feet long; and a powerhouse with four Francis type turbine-generator units. Unit 1 turbine is rated at 22,000 kW under a design head of 172 feet and Units 2-4 each are rated at 49,600 kW under a design head of 172 feet. The combined rated discharge of the four units is 12,990 cfs. Unit 1 generator is rated at 39,000 kVA and a 0.9 power factor, yielding a rated capacity of 35,100 kW. Unit 2-4 generators, having been recently rewound, are rated at 54,000 kVA and a 0.9 power factor, yielding rated capacities of 48,600 kW each. The overall rated plant generator capacity is 180,900 kW. Maximum station output at full load is 162,960 kW under a net head of 174 feet and combined turbine discharge of 13,300 cfs. In addition, the Station contains several ancillary components such as: crane station, crane service bldg., bubbler, black start generator, LP gate, and an emergency generator. [8 & 9]

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[7] The North Star Monthly – *The Fifteen Mile Falls area changed forever in 1928.*
[8] Low Impact Hydropower Institute – Fifteen Mile Falls (LIHI Cert. # 39) Recertification Application January 2022 | Page 6 - 12
[9] Great River Hydro, LLC response to Request for Information & Production of Documents from the Town of Monroe, NH – July 2023

Figure 4: Comerford Station[10]

Figure 5: The Historical Comerford Operation Button[11]

[10] Comerford Hydroelectric Station – Great River Hydro
[11] Comerford Hydroelectric Station – Great River Hydro

Figure 6: Comerford Dedication Plaque

Figure 7: Comerford Station Dam

Figure 8: Comerford Interconnection

[redacted]

[redacted]

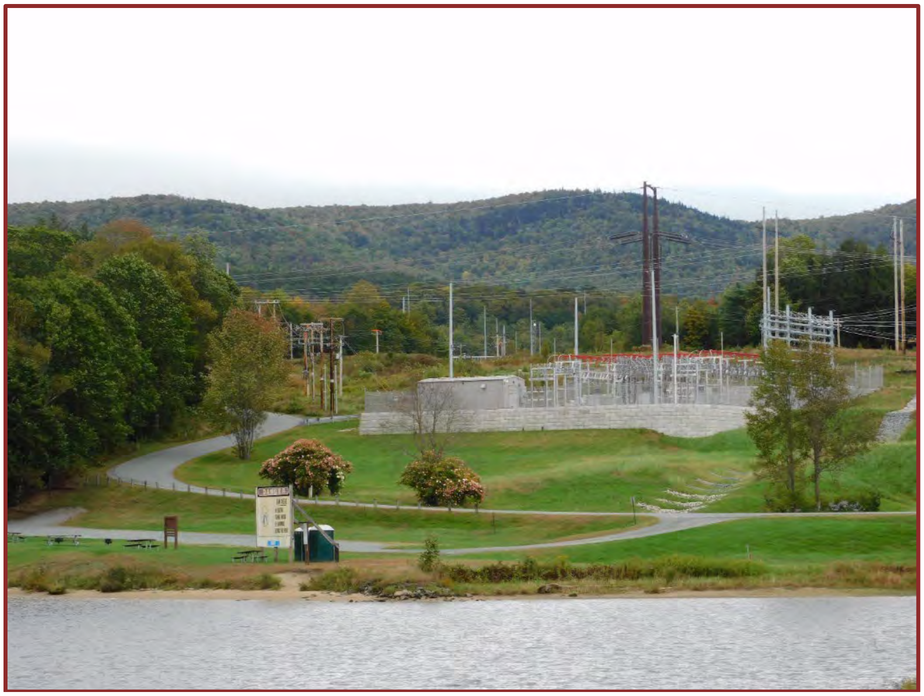

Figure 10: Comerford Substation

McIndoe Development

The McIndoe Development is located at RM 268 and has an overall rated plant generator capacity of 10.56± MW with a summer capacity ratting of 10.2± MW. The Development began commercial operation in 1931.

The McIndoe Development is a seasonal storage development operated as a peaking facility due to its upstream connection with the Moore and Comerford Developments and their methods of operation. The McIndoe Development is primarily used to capture and smooth the discharge from the two upstream developments by discharging itself at a more constant rate throughout each day in comparison with the two upstream developments. The McIndoe generation schedule results in a building of the head-pond throughout the day and a draw down overnight due to the upstream generation schedule priority of the Comerford & Moore Stations. The McIndoe Development consists of: a 5-mile-long reservoir with a surface area of 465 acres and 4,500 acre-feet of gross storage at a normal maximum operating level of 451 feet msl; a concrete gravity dam with an overall length of 730 feet and a max height of 25 feet; a 520-foot-long concrete spillway with a 12-foot-wide by 13- foot-high skimmer gate, three 24-foot-wide by 25-foot-high Steel Tainter gates, a 300-foot-long spillway flashboard section with 3-foot-high flashboards, and two 50-foot-wide by 14-foot-high stanchion bays; and a powerhouse with four Kaplan type turbine-generator units. The turbines have a combined power rating of 2,850 kW each under a design head of 29 feet. The combined rated discharge of the four units is 5,800 cfs. Each generator is rated at 2,640 kW, yielding an overall rated capacity for the station of 10,560 kW. Maximum output at full load is 11,000 kW, under a net head of 23 feet and a maximum turbine discharge of 6,180 cfs. In addition, the Station contains several ancillary components such as: crane, trash rake, bubbler, black start generator, and surge tank. [12 & 13]

Figure 11: Downstream view of McIndoe Development[14]

[12] Low Impact Hydropower Institute – Fifteen Mile Falls (LIHI Cert. # 39) Recertification Application January 2022 | Page 6 - 12
[13] Great River Hydro, LLC response to Request for Information & Production of Documents from the Town of Monroe, NH – July 2023
[14] Comerford Hydroelectric Station – Great River Hydro

Figure 12: Upstream view of McIndoe Development[15]

Figure 13: Dam and Bypass McIndoe Development

[15] Comerford Hydroelectric Station – Great River Hydro

Figure 14: McIndoe Crane

[redacted]

[redacted]

[16] Comerford Hydroelectric Station – Great River Hydro

Unit Operating Data for the Developments

Hydroelectric plants have several operational constraints that may be universal to hydroelectric facilities in general or to plant specific facilities due to location and the surrounding environmental and infrastructural constrains either to the plant and/or the river system. One of these constraints that affect the operation of the hydroelectric facility is the environmental seasonal effects on the stream flow of the river and therefore the capacity of the plant. For example: hydroelectric facilities located in the northeastern region of the U.S. typically experience a higher capacity in the winter-spring months than in the summer-fall months due to the melting of snow and larger amounts of precipitation on average.

A summary of the units' operating data is provided in Table 1.

Table 1: Unit Data for the Developments

	A	B	C	D	E	F
		Capacity (MW)				
Row	Generator Unit	Nameplate	Summer	Winter	Primary Fuel	Operating Year
1	***Comerford Development***					
2	GEN1	22.0	22.5	22.5	Water	1930
3	GEN2	48.6	47.8	48.5	Water	1930
4	GEN3	48.6	47.8	48.5	Water	1930
5	GEN4	48.6	47.8	48.5	Water	1930
6	*Subtotal:*	***167.8***	***165.9***	***168.0***		
7	***McIndoes Development***					
8	GEN1	2.6	2.3	2.4	Water	1931
9	GEN2	2.6	2.3	2.4	Water	1931
10	GEN3	2.6	2.8	3.0	Water	1931
11	GEN4	2.6	2.8	3.0	Water	1931
12	*Subtotal:*	***10.4***	***10.2***	***10.8***		

Energy Generation

Great River Hydro's facilities on the Connecticut River have a combined qualified capacity of 492± MW and an average annual generation of approximately 1,325,000 MWh. Great River Hydro has significant control of the river beginning at its dams on First and Second Connecticut Lakes. From the Second Connecticut Lake to the Massachusetts border, approximately 73% of the head water of the Connecticut River is captured for hydroelectric production.[17]

The amount of energy that a hydroelectric plant generates during on-peak hours versus off-peak hours is critical in the overall profitability for the plant because on-peak energy sells at a higher price than

[17] http://des.nh.gov/organization/divisions/water/wmb/rivers/conn2.htm; The CT River A Report to the General Court, December 1991; page 2, 2d.

off-peak energy. A typical run-of-the-river hydroelectric plant will generate 47% of its energy on-peak (non-holiday weekdays, 7 AM to 11 PM) and 53% off-peak (11 PM to 7 AM non-holiday weekdays, all day on holidays and weekends).

Both Comerford and McIndoe's on-peak generation is greater than that of the typical hydroelectric plant. Even further, Comerford and McIndoe's on-peak generation is actually greater than its off-peak generation. Historically higher than typical on-peak percentages at the Developments indicate that both stations benefit from the significant control capabilities on the Connecticut River beginning at its source. This ability to control nearly the entire river from its source to the tailrace of Vernon Project and beyond allows GRH to make the best use of its available water without violating its Federal Energy Regulatory Commission (FERC) license requirements for minimum flows, etc. This ability to capitalize on the storage and control features both upstream and at the individual plants makes the Connecticut River hydroelectric system unique in the marketplace.

Table 2 through Table 5 below provides the historic annual generation as well as on & off-peak generation for the Developments, which was sourced from EIA and GRHs company submissions. We utilize the following annual average generations for the Developments going forward for this appraisal:

- Comerford Station: **340,400 MWh**
- McIndoe Station: **43,600 MWh**

Table 2: Comerford Annual Generation

	A	B
Row	**Year**	**Annual Generation (MWh)**
1	2010	376,036
2	2011	399,084
3	2012	303,785
4	2013	323,769
5	2014	353,821
6	2015	343,613
7	2016	292,603
8	2017	380,902
9	2018	352,123
10	2019	417,566
11	2020	324,177
12	2021	230,921
13	2022	326,209
14	*Average:*	***340,355***

Table 3: McIndoe Annual Generation

	A	B
Row	**Year**	**Annual Generation (MWh)**
1	2010	49,444
2	2011	48,210
3	2012	41,895
4	2013	47,144
5	2014	40,981
6	2015	42,171
7	2016	44,557
8	2017	34,406
9	2018	45,464
10	2019	48,539
11	2020	44,241
12	2021	35,399
13	2022	44,569
14	*Average:*	***43,617***

Table 4: Comerford On & Off-Peak Generation

	A	B	C	D
		Generation (MWh)		
Row	Year	All Hours	On-Peak	Off-Peak
1	2010	376,036	[redacted]	[redacted]
2	2011	399,084	[redacted]	[redacted]
3	2012	303,785	[redacted]	[redacted]
4	2013	323,769	[redacted]	[redacted]
5	2014	353,821	[redacted]	[redacted]
6	2015	343,613	[redacted]	[redacted]
7	2016	292,603	[redacted]	[redacted]
8	2017	380,902	[redacted]	[redacted]
9	2018	352,123	[redacted]	[redacted]
10	2019	417,566	[redacted]	[redacted]
11	2020	324,177	[redacted]	[redacted]
12	2021	230,921	[redacted]	[redacted]
13	2022	326,209	[redacted]	[redacted]
14	*Average:*	***340,355***	[redacted]	[redacted]

Total of On-Peak:	[redacted]	[redacted]
Total of Off-Peak:	[redacted]	[redacted]

Table 5: McIndoe On & Off-Peak Generation

	A	B	C	D
		Generation (MWh)		
Row	Year	All Hours	On-Peak	Off-Peak
1	2010	49,444	[redacted]	[redacted]
2	2011	48,210	[redacted]	[redacted]
3	2012	41,895	[redacted]	[redacted]
4	2013	47,144	[redacted]	[redacted]
5	2014	40,981	[redacted]	[redacted]
6	2015	42,171	[redacted]	[redacted]
7	2016	44,557	[redacted]	[redacted]
8	2017	34,405	[redacted]	[redacted]
9	2018	45,464	[redacted]	[redacted]
10	2019	48,539	[redacted]	[redacted]
11	2020	44,241	[redacted]	[redacted]
12	2021	35,399	[redacted]	[redacted]
13	2022	44,569	[redacted]	[redacted]
14	*Average:*	***43,617***	[redacted]	[redacted]

Total of On-Peak:	[redacted]	[redacted]
Total of Off-Peak:	[redacted]	[redacted]

Property Tax Rate

A breakdown of the Municipality's tax rate is set forth in Table 6. The Developments are not subject to the Monroe portion of the State Education Tax, but instead, they are considered by the NHDRA (New Hampshire Department of Revenue) to be utility property that is subject to the New Hampshire 83F Utility tax at a rate of $6/1000.

Table 6: Monroe Property Tax Rate

	A	B	C	D	E	F	G	H
			Tax Rate [$/1000]				Total Tax Rate [$/1000]	Net Utility Tax Rate [1] [$/1000]
Row	Municipality	Year	Municipal	County	State Ed.	Local Ed.		
1	***Monroe, NH***							
2		2018	1.35	1.21	2.07	6.06	10.69	15.22
3		2019	1.52	1.46	2.00	6.36	11.34	15.94
4		2020	2.08	1.85	1.90	7.28	13.11	17.81
5		2021	1.70	1.73	1.70	6.65	11.78	16.68
6		*2022*	***2.02***	***1.78***	***1.36***	***7.03***	***12.19***	***17.43***

[1] Utility Property in New Hampshire is not subject to the State Education Tax. Therefore, the *Total Tax Rate - State Ed. Rate + 6.60 = Net Utility Tax Rate*

Zoning Data

The Developments are located in a variety of zoning jurisdictions in Monroe, New Hampshire, and Barnet, Vermont located along the Connecticut River. In most cases, the Developments are non-conforming uses which pre-date the existence of zoning in the various towns. Therefore, the Developments' non-conforming uses are considered typical. In addition, electrical generating facilities are typically permitted by FERC, or by the Vermont and/or New Hampshire Energy Facility Siting Processes.

Previous Assessment

A summary of the previous year's assessment in the Town of Monroe, NH is provided below in Table 7. The taxable property which makes up the total Developments is inclusive of land, real property improvements, and personal property.

Table 7: Previous Assessment

	A	B	C	D	E	F
				2022 Assessed Value		
Row	Parcel/Tax ID	Description	Acres	Land	Imrpovements	Total
1	***Great River Hydro - Land Values in Monroe, NH***					
2	R04-003	Vacant Fee Land	*1.1*	$400	-	$400
3	R04-004	Vacant Fee Land	*13*	$9,900	-	$9,900
4	R08-006	Vacant Fee Land	*38.2*	$83,100	-	$83,100
5	R08-007	Vacant Fee Land	*10*	$7,800	-	$7,800
6	R08-008	Vacant Fee Land	*65*	$19,200	-	$19,200
7	R11-011	Vacant Fee Land	*86*	$86,000	-	$86,000
8	R11-012	Vacant Fee Land	*81*	$138,900	-	$138,900
9	R11-013	Industrial Land	*5*	$170,000	-	$170,000
10	R11-014	Vacant Fee Land	*94.6*	$118,200	-	$118,200
11	R11-022	Vacant Fee Land	*28*	$19,900	-	$19,900
12	R11-023	Vacant Fee Land	*14*	$42,600	-	$42,600
13	U02-048	Vacant Fee Land	*17.3*	$41,600	-	$41,600
14	U03-008	Vacant Fee Land	*0.147*	$400	-	$400
15	U03-009	Industrial Land	*5.2*	$52,000	-	$52,000
16	U03-010	Vacant Fee Land	*1.3*	$3,300	-	$3,300
17	U03-011	Vacant Fee Land	*0.15*	$400	-	$400
18	U03-012	Industrial Land	*0.33*	$3,300	-	$3,300
19	U03-013	Vacant Fee Land	*20.58*	$48,500	-	$48,500
20		***Subtotal:***	*480.91*	$845,500	$0	$845,500
21	***Great River Hydro - Improvements in Monroe, NH***					
22	000-007	*Comerford Station*			$174,951,000	
23	000-007	*McIndoe Station*			$12,319,900	
24		***Total Assessment of Property:***	*480.91*	$845,500	$187,270,900	**$188,116,400**

MARKET ANALYSIS

Energy Markets

For this report, we continue to rely on energy price forecasts that are designed to forecast ISO wholesale (spot) prices into the future. We rely on these forecasted "spot" prices as the basis for the revenues earned by the Developments in our discounted cash flow analyses for this report, but we do so with an eye on the current market sales and market sales trends. We recognize that most buyers of hydroelectric facilities rely on forecasted cash flows in their buying decisions, and that buyers are often conservative in their estimates of cash flows. We also recognize the fact that if buyers are to make successful bids for the prospective purchase of a hydroelectric facility, they will have to be competitive with those buyers who have affiliated power marketing companies. These types of buyers can, and do, consider their ability to add value to a prospective purchase by using their power marketing affiliate's ability to remarket the energy produced at the hydro being considered for purchase.

The price of energy at any given time is a function of the intersection of supply and demand for electricity at a particular location. In the short-run, supply is relatively constant therefore demand is typically satisfied by existing units with prices established through some form of least cost bidding. Since demand is constantly fluctuating from minute to minute, hour to hour, day to day, and season to season, generating units are dispatched based on a system where the least cost bid which satisfies the last increment of demand establishes a marginal price which reflects the price of energy that will be received by all participating units. This price is called the Locational Marginal Price (LMP) (Locational due to the various regions this price is set in order to account for locational influences on the price of electricity such as congestion or demand). This type of bidding results in all lower bidders receiving the marginal price, or selected bid, of the last unit bid and results in units with low costs and corresponding low bids operating more hours of the year relative to more expensive units with higher costs. Hydroelectric facilities have no fuel costs, and therefore submit bids near zero. Generating resources like this (such as nuclear, wind, solar, etc.) are called "price takers", and do not typically have a minimum price necessary to dictate if the resource can run or not run.

The price of wholesale electricity is primarily a function of two commodities, which are *energy* and *capacity* (although additional commodities exist). The energy price typically represents the price necessary to produce a kilowatt-hr or megawatt-hr of electricity. The capacity price typically represents the payment necessary to support investments for generation resources. ISO-NE utilizes a capacity market to ensure and secure enough generating resources to meet peak demand and thus ensure reliability and availability of power. Typically, the capacity price reflects the necessary revenue to attract new generation investment of a combined cycle gas turbine plant, although this price can fluctuate based on current market conditions.

ISO New England

ISO-New England (ISO-NE) serves as the independent, non-profit Regional Transmission Organization for New England.[18] ISO-NE is responsible for the reliability, sustainability, and

[18] ISO-NE 2003 Annual Report

settlement of electricity in the region. The current energy market consists of "Day-Ahead" and "Real-Time" markets for electricity for each node within the eight zones discussed below. The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before the day of operation. The real-time market reconciles any difference occurring between the day-ahead schedule and the real-time load.

On March 1, 2003, the ISO-NE Standard Market Design (SMD) was implemented and included Locational Marginal Pricing (LMP) for eight zones in New England.[19] The SMD zones correspond with geographic regions and are as follows:

- Maine
- New Hampshire
- Vermont
- Rhode Island
- Connecticut
- Western/Central Massachusetts
- Northern Massachusetts (including Boston)
- Southeastern Massachusetts

The LMPs are calculated for each zone based on a load-weighted average of the node prices in each zone. As the market matures, these zones and nodes will inevitably change due to changes in the electric system's physical characteristics and the regional economics of each location.[20]

Day-Ahead Market (DAM)

The DAM provides clearing prices for generation, demand, and external contracts a day prior to operation. In the DAM, participants submit supply offers and demand bids for energy for each zonal location. The ISO-NE constructs zonal supply and demand curves for each location to determine clearing prices for the day-ahead LMP.[21]

Real-Time Market (RTM)

The RTM is a spot market for energy. The DAM can differ from the RTM when demand bids are not identical to the actual demand, or unforeseen generation or transmission outages, transmission constraints or changes from expected demand results in revised supply and demand situations.[22] The RTM offers generators the opportunity to offer additional supply or, if conditions warrant, the ISO-NE may call on certain generators for reliability purposes.

[19] ISO-NE 2003 Annual Report
[20] This is evidenced by the creation of the SWCT (southwestern Connecticut) load zone (FERC, Order on Compliance Filing, Docket No. ER03-563, November 8, 2004).
[21] ISO NE 2016 Manual
[22] ISO-NE 2016 Manual

Energy Price Forecast

The present and future price of wholesale electricity and capacity are among the most important factors in determining a generating facility's market value. The formation of electric prices is typically driven by several region-specific factors which include demand for wholesale electric commodities, the amount of megawatts available, the type of plants within the zone, fuel source and availability, cost of fuels, and market structure.

Natural gas has become the dominant fuel used to produce electricity in the region and is no longer dependent on the price of oil because it is produced domestically and its supply and demand no longer flows with the supply and demand of oil. However, the price of oil still sets the maximum price of electricity in New England because utilities are capable of fuel switching between natural gas and oil. As of the valuation date, New England energy markets remain relatively flat to slightly rising as the price of natural gas has begun to increase from its recent historic lows.

Because electric energy prices fluctuate, we develop our income approach for this appraisal by utilizing a 20-year DCF analysis, and to develop our DCFs we require forecasts of revenues (and expenses) for each of the 20 years. As stated earlier, energy markets are not primarily driven by inflation solely or other common metrics by which we can simply escalate current energy prices, so it is essential that we employ energy market price forecasts that reflect the variables which drive electricity prices year over year. We have developed an energy price forecast based on the key drivers of price fluctuations, primarily the price of gas.

Natural gas is the primary driver behind the price of electricity (LMP) in New England, as shown in Figure 16. To determine the forecasted price of electricity based on this relationship, we first looked at the various forecasts available for the Henry Hub gas pricing point in Louisiana. Henry Hub is typically representative of the wholesale price of gas before transmission costs for the US, as it interconnects with nine interstate pipelines which feed gas to much of the US. Additionally, NYMEX offers standardized gas contracts based on the Henry Hub prices. Wellhead prices typically follow Henry Hub prices.

There is a strong correlation between the Henry Hub and the price of natural gas and the average wholesale price of natural gas in New England, as well as the average wholesale price of natural gas in New England and the price of electricity. The Henry Hub, due to its importance to the United States gas supply, serves as the primary price point for natural gas futures contracts. Transportation costs, pipeline costs, additional operation, maintenance, markup, and fees contributed to a generally higher price of natural gas in New England, but price fluctuations typically move up and down with the Henry Hub spot price. Likewise, as natural gas is the primary fuel in New England for power generation, the electricity price is heavily correlated with the wholesale price of natural gas in New England. From these indicators, and utilizing multiple Henry Hub forecasts, we can compute a forecasted average wholesale price of electricity for the DCF period. Additional adjustments were made for inflation utilizing an energy specific CPI for the region.

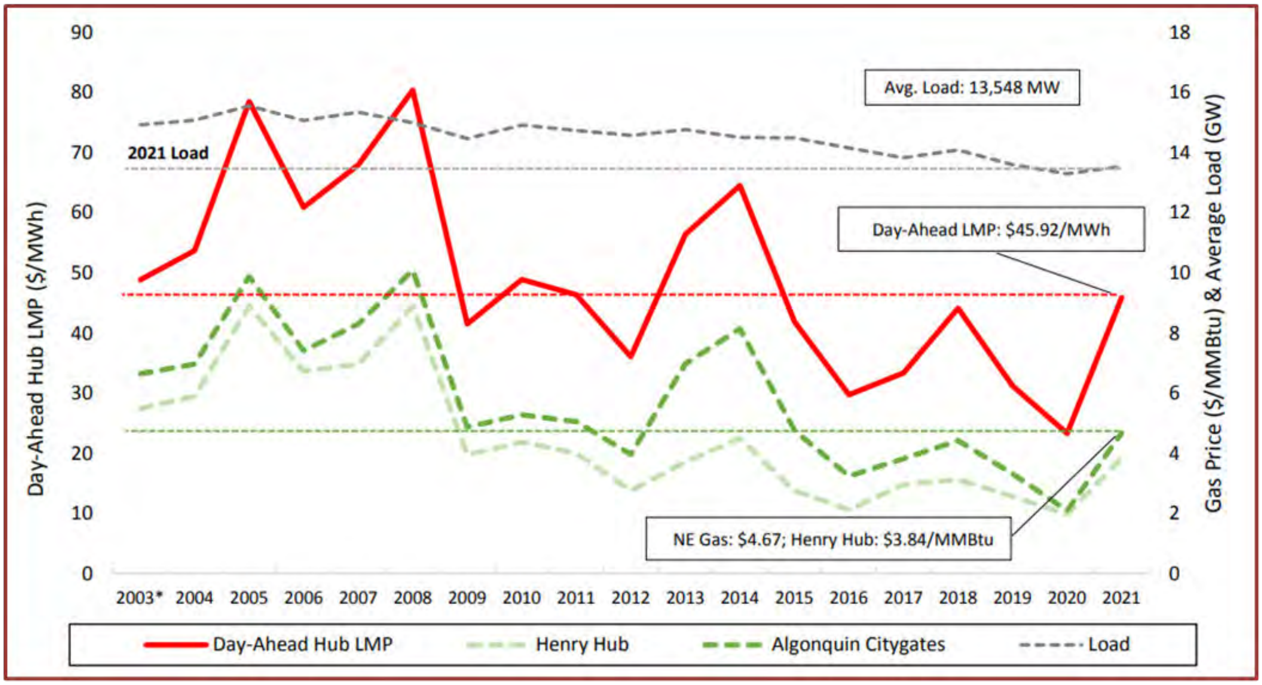

Figure 16: ISO-NE Natural Gas vs Day-Ahead LMP[23]

Capacity Market

Generally, hydroelectric facilities are qualified, at some level of capacity, to receive capacity payments to compensate the owners of the facility for its availability to the market. These payments are made to hydro owners based on the facility's "qualified" capacity, which is reported by ISO-NE in its Forward Capacity Auction (FCA) Markets website. We rely on the ISO-NE reported "qualified" capacity in our DCF analyses.

The Forward Capacity Market (FCM) is designed to promote adequate and economic investment in supply and demand reduction resources throughout ISO-NE's various regions. The FCM is a result of a FERC Settlement filed in early 2006 which establishes transition payments from December 31, 2006, through May 31, 2010. As part of the Settlement, an FCA will be held each year approximately three years in advance of the resource period. For example, the FCA 14, completed in 2020, sets the capacity price from June 1, 2023, to May 31, 2024.

Due to the excess amount of capacity in the region and the auction clearing at the floor prices for auctions 1-7, payments are prorated to all of the capacity which is bid into each auction. In FCA 8, the price cleared at the ceiling and capacity was paid based on the administrative ceiling. The results of the auctions and prorated prices are set forth in Table 8.

[23] ISO-NE 2021 Annual Report, p 2 Figure 1-1

Table 8: Forward Capacity Auction Results[24]

	A	B	C	D	E
Row	FCA #	Capacity Commitment Period	Capacity Clearing Price [$/kW - Month]	Payment Rate [$/kW - Month]	Date(s) of Auction
1	FCA 5	June1, 2014 - May 31, 2015	$3.21	$2.86	Jun 6-7, 2011
2	FCA 6	June1, 2015 - May 31, 2016	$3.43	$3.13	Apr 2-3, 2012
3	FCA 7	June1, 2016 - May 31, 2017	$3.15	$2.74	Feb 4-5, 2013
4	FCA 8	June1, 2017 - May 31, 2018	$15.00	$7.03	Feb 3, 2014
5	FCA 9	June1, 2018 - May 31, 2019	$9.55	$9.55	Feb 2, 2015
6	FCA 10	June1, 2019 - May 31, 2020	$7.03	$7.03	Feb 8, 2016
7	FCA 11	June1, 2020 - May 31, 2021	$5.30	$5.30	Feb 6, 2017
8	FCA 12	June1, 2021 - May 31, 2022	$4.63	$4.63	Feb 5-6, 2018
9	FCA 13	June1, 2022 - May 31, 2023	$3.80	$3.80	Feb 4, 2019
10	FCA 14	June1, 2023 - May 31, 2024	$2.00	$2.00	Feb 3-4, 2020
11	FCA 15	June1, 2024 - May 31, 2025	$2.61	$2.61	Feb 8, 2021
12	FCA 16	June1, 2025 - May 31, 2026	$2.59	$2.59	Feb 7, 2022
13	FCA 17	June1, 2026 - May 31, 2027	$2.59	$2.59	Mar 6, 2023

The capacity market in New England has been increasingly vulnerable, producing large swings in auction results and payment rates based on the action and reaction of generators, new entries, and renewables, which may or may not rely on the capacity market for economic viability. Generator retirements, new entries, weather inconsistencies, and changes to the auction mechanics have contributed to the volatility in the past 10 years. Further, an influx of renewable energy generation facilities that have been proposed and sponsored through state renewable energy initiatives have altered traditional market dynamics of supply and demand, further impacting the capacity prices and the FCM. The underlying principles of a relatively untested capacity market are beginning to show shortcomings in a rapidly changing energy market.

The ISO-NE has recognized this vulnerability and has begun to take measures to, at a minimum, observe the need for and propose changes in market mechanics and additional compensation. The first of these changes began with Forward Capacity Auction 13, where a substitute auction was held separate from the primary auction for entry of sponsored preemptive renewable resources in an attempt to maintain competitive pricing in the primary auction. This enhancement, CASPR (Competitive Auctions for Sponsored Policy Resources), allows sponsored resources to buy out the capacity supply obligations held by older, higher-emitting generators.[25] This auction mechanism can help alleviate some of the price suppression caused by renewable energy sources, while maintaining compensation to the conventional generators through a "secondary market".
Secondly, the ISO has begun to formulate a market that recognizes the key components to a reliable energy system going forward. These components include attributes such as carbon free resources, on-site fuel storage, battery and energy storage, and fuel diversity. As stated in the 2019 ISO-NE Regional Electricity Outlook, the ISO has implemented measures to protect and enhance price formations

[24] ISO-NE Forward Capacity Auction Result Report
[25] ISO-NE Participant Readiness Project Outlook CASPR Project

during scarcity and surplus conditions, as well as strengthened financial consequences for resources that do not perform as committed.[26] Additional economic incentives are being developed to help keep some resources from retiring prematurely, incentivize fuel storage, and encourage operational flexibility. As quoted from ISO-NE, "Through this new market construct, the pricing signals will have to motivate resources to alleviate the energy-security problem and may result in periodic higher prices and volatility." [27]

The vulnerabilities associated with the FCM structure came to the forefront in 2018 when Mystic Generating Station announced its retirement in 2022, putting the Distrigas LNG Import Terminal at risk of closure.[28] This accelerated the analysis and implementation of a temporary solution to address and compensate generators with fuel security, and generators contributing to the fuel diversity of the region. Beginning with FCA 14, a separate auction for fuel storage, titled Seasonal Interim Settlement Mechanism, has been introduced to incentivize conventional generators and new technologies to invest in fuel security measures, such as coal stocks, battery storage, on-site nuclear fuel, pumped storage, and gas storage. [29] This additional auction mechanism is an example of the necessary changes to the fundamental principles of the electric market in ISO-NE. As annual energy use and consumption and required capacity continues to be stagnant or decline and historic grid demand patterns are being upended, the need for a functioning, stable, and reliable grid is not changing, and is beginning to be brought to the forefront of attention.

To replace the Seasonal Interim Settlement Mechanism, ISO-NE is implementing a Day-Ahead Ancillary Service which is focused on procuring response services to cover the gap of day-ahead awards and ISO-NE's real-time energy forecasts. Additionally, ISO-NE is seeking solutions to address resource adequacy from an operational level. Currently, ISO-NE is identifying methodologies to qualify generation resources based on not only their design capabilities, but the certainty of that generator's availability when considering seasonal impacts such as firm fuel capacity, onsite fuel storage, stored water, and firm pipeline capacity.

Beginning in winter 2018/2019, the ISO began forecasting a 21-day energy assessment of New England, giving generators advanced notice to schedule fuel deliveries and availability to help maximize their participation in the energy market. Generators are now also allowed to include an opportunity cost in their day-ahead offers to reflect the costs associated with preserving fuel when supplies are limited. [30]

One of the most significant changes to the capacity market is the implementation of a pay for performance (PFP) payment, which is separate from the Forward Capacity Auction. [31] This PFP reallocates capacity payments from resources that do not perform their obligations to resources that perform above their obligations during times of system stress. This system was implemented in the winter of 2018/2019.

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[26] ISO-NE 2019 Regional Electricity Outlook, January 2019, pp. 35-36
[27] ISO-NE 2019 Regional Electricity Outlook, January 2019, p. 4
[28] Business Wire "Exelon Generation Files to Retire Mystic Generating Station in 2022, Absent any Regulatory Solution." March 29, 2018
[29] ISO-NE 2019 Regional Electricity Outlook, January 2019, p. 36
[30] ISO-NE 2019 Regional Electricity Outlook, January 2019, p. 35
[31] ISO-NE 2019 Regional Electricity Outlook, January 2019, p. 35

Finally, market changes to the way generators receive revenue may shift away from the capacity market altogether as alternative markets and services are created. As of today, ISO has submitted several proposals to FERC and continues to develop additional commodities within the ancillary service market which are focused on grid and fuel reliability and stability, or "Energy Security".

These initial changes to the market mechanics will play a vital role and signal the evolution of the fundamental principles of the ISO-NE. However, the effects of the shortcomings currently existing in the market are already being felt and may outpace the reaction of the ISO and implementation of these new market mechanics. As discussed previously, the announcement of the closure of Mystic and the swift action taken by the ISO to issue the Reliability Must Run contract indicates that the tipping point of the capacity pricing decline has already been reached, as it is evident that the ISO recognizes that the capacity market is not compensating generators critical to the safe operation of the grid at the level necessary to be economically feasible. While the retirement of Mystic would traditionally be normal within a competitive marketplace (i.e., the introduction of lower cost, higher efficiency technology drives the continued improvement of the system through replacement), infrastructure constraints and reliability concerns are not allowing the market to act in a strictly competitive manner.

Natural gas constraints have been of considerable concern to the ISO-NE as well as to new entrants who simply cannot procure the level of gas needed to run consistently and economically without the closure of another plant. These constraints are impacted even further by the depressed capacity pricing, squeezing the margins of potential new entrants past the point of feasibility. Consistently, natural gas demand exceeds the pipeline capacity of approximately 4 billion cubic feet per day (Bcf/d) in the winter months, putting a heavy reliance on peak shaving facilities and import terminals.[32] Compounding this issue is the foreseeable increase in natural gas exports out of the northeastern and northcentral United States region and out of the country as more LNG export facilities are being constructed. Naturally, end users in New England will be required to compete for supply with exporters as the ability to export gas becomes easier.

In summary, neither the pipeline capacity nor the capacity market is adequate to attract new entrants into the current FCM. While the latest capacity auction (FCA 17) closed at a clearing price of \$2.59/kW-mo.,[33] the current Cost of New Entry (CONE) for FCA 18 has been finalized at \$14.22/kW-mo. (\$170.64/kW-yr.) for a combined cycle plant.[34] This indicates that even if pipeline capacity were available, which it is not, a combined cycle plant would likely not be built until the compensation levels increased to or above the CONE, either through the capacity market or ancillary and other service payments. Logical markets, including ISO-NE, can be temporarily upset by illogical entries of plants which are not apparently economically feasible, from time to time.

While it remains uncertain of the finalized energy landscape and how exactly it will compensate resources, we are certain that there are currently and will be additional compensation mechanisms available to conventional generators in the very near future. ISO-NE has also recognized this expected rise in compensation;

[32] ISO-NE Operational Fuel-Security Analysis, January 12, 2018, p. 23
[33] ISO-NE Forward Capacity Auction Result Report FCA 17
[34] ISO-NE ORTP Summary "Forward Capacity Market Parameters"

"The capacity market value over the past two years was higher, reflecting a rash of generation retirements that led to a smaller amount of competing supply and thus higher prices. Strong competition has generally kept capacity market auction prices low for most years. However, as energy-market revenues decrease over time, the prices in the capacity and ancillary markets will likely rise to cover the costs for resources that rely solely on market revenue (i.e., without state- and federal-based incentives) needed to balance renewable resources and provide energy security, particularly in winter." [35]

For these reasons, and the reasons discussed above, we choose to account for these additional compensation mechanisms in the capacity payment rate, although it will most likely be a blend of capacity payments and ancillary service or other payment types. We therefore utilize the actual auction results for DCF periods 1 through 4 (2023 through 2026) and a multi-scenario model which analyzes the future earning potential of the Developments under three conditions:

- Forecasted capacity price which normalizes to 2/3 of the CONE price, adjusted for inflation. This scenario represents a market which recognizes the need for additional generation, drifting towards a price attractive enough to spur new development.
- Forecasted capacity price which normalizes to 1/3 of the CONE price, adjusted for inflation. This scenario represents a continued suppressed market for the foreseeable future, which may be suppressed due to the prevention of retirement of older units such as Mystic, or the inundation of renewable energy into the market.
- Forecasted capacity price which normalizes to the average historic capacity price, adjusted for inflation. This scenario provides a guideline based on the historic performance of the capacity market, and if that performance continued into the foreseeable future.

Renewable Energy Certificates (RECs)

Hydroelectric facilities are generally considered to be renewable power generators and, as such, many of them are eligible to sell Renewable Energy Certificates, which are more commonly referred to as RECs. The eligibility for the sale of RECs is determined for each individual facility by one or several criteria that are facility-specific and several criteria that are State- or region-specific. Certain facilities qualify because they have made plant improvements that increase generation, and this "incremental" generation commonly qualifies the facility for Class I RECs, which are often sold in the Connecticut, New Hampshire, and Massachusetts REC markets. In most markets, Class I RECs sell for the highest prices for hydro RECs compared to other classes of RECs. New "incremental" generation is usually approved by FERC when the operator files a request to be approved for Federal Production Tax Credits. FERC's approval of this type of request is generally the mechanism that "qualifies" a facility to sell Class I RECs. Most states have Renewable Portfolio Standards (RPS) that set forth the conditions under which a hydro facility (or other renewable facility) may sell RECs. For instance, Massachusetts allows small hydro's (less than 7.5 MW capacity) located in the region to sell Class II RECs if they meet certain requirements set by the Low Impact Hydropower Institute. Once qualified, these facilities are generally eligible to sell Class II RECs for all, or most, of their generation. Each state in the region has its own RPS, but generally operators are allowed to sell their RECs in any of the markets that are located in the region.

[35] ISO-NE 2019 Regional Electricity Outlook, January 2019, p. 20

The Comerford Development has been awarded Class I RECs from the State of New Hampshire (Revised Authorization 6-4-2021) and RPS Class I RECs from the State of Massachusetts. The New Hampshire Class I RECs NH Certification Number (NH-21-1-0041) was authorized on 6-4-2021 to reflect the increase in capacity of the facility from 162 MW to 169 MW (began commercial operation as of March 22, 2013) granting of NH Class I REC eligibility for all generation over the annual historical generation baseline of 298,236 MWh.[36]

Comerford Station has been awarded RPS Class I RECs (1405-15) from the State of Massachusetts back in 2015. Comerford Station was awarded an Output Qualification of 5.70% of total Generation. In addition, Comerford is qualified for Vermont Tier I (100% of Generation), LIHI (100% of Generation), and CT CEO (Unit 1 only – 100%)

The McIndoe Station has been qualified for ME Class II, RI Existing, CT CEO, VT Tier I, and LIHI (all 100%) of generation produced.

[36] New Hampshire Public Utilities Commission – Revised Authorization for Class I Renewable Energy Certificate (REC) Eligibility

POTENTIAL BUYERS

Introduction

There is currently a relatively robust market for hydroelectric facilities of almost all capacities in the region and this market appears to be driven by several factors. One factor is the relative reliability of positive cash flows derived from hydroelectric operations that are located on quality rivers utilizing proven and mature technology. Positive cash flows for hydroelectric facilities are generally a function of energy markets, low operating costs relative to other generation properties due primarily to the exclusion of fuel costs, and the relatively long useful lives of the infrastructure and a majority of the equipment. Many of the operating hydroelectric facilities in the region were originally constructed in the early 1900s and are still utilizing the original dams, gates, generators, and turbines. Additionally, modern computer technology, coupled with hydraulic controls, has allowed automation to be introduced to the operation of the facilities, lowering the operating costs even further. Many hydroelectric facility owners own and operate several plants and are able to perform much of the operations from a central location. There are three primary types of buyers for the Developments which can competitively and actively seek hydroelectric plants for purchase and hold the buying power necessary for the acquisition of a hydro station.

Independent Merchant Owner Operators

This includes several independent owner operators who are actively seeking to purchase large to mid-size hydroelectric plants in the area such as the current Owner, Hull Street Hydro, Eagle Creek, Central Rivers Power, LS Power, and others. There are other, larger international entities that have been active buyers of these types of properties for the last several decades. Examples are companies such as Italy-based Enel, Canada-based Brookfield Power, Ontario Power Generation, NextEra, FirstLight, Hydro-Quebec, and others. These companies, and others, currently own facilities of similar capacity to the Developments in the region. This relatively large pool of potential buyers for properties like the Developments has the effect of maintaining the sales prices of hydroelectric facilities in the area. This relative market stability occurs even during a period of flat or slowly increasing energy prices.

Regulated Utilities

Vermont hosts one of the largest hydroelectric owner-operators in New England, Green Mountain Power. Green Mountain Power, who owns the largest fleet of hydroelectric plants in New England, has committed to 100% carbon-free by 2025 and 100% renewable by 2030. GMP has and continues to seek viable plants to purchase or contract with and add to their growing fleet of renewable energy procurement and does so with continued support of regulators. Their model may be emulated by other regulated utilities in the region in an effort to procure clean energy for their customers.

Tax Exempt or Municipal Ownership

In addition to this sampling of the more common likely buyers, there are also electric cooperatives and power authorities comprised of taxable and nontaxable municipality groups or entities such as the New York Power Authority.

COST APPROACH

Introduction

The cost approach is one of the three primary approaches used to develop an indication of market value. The cost approach is based upon the assumption that a buyer would pay no more for the subject than the cost of producing an equally desirable substitute, assuming no undue delay in creating the substitute property. The cost approach is most relevant when the property is new and constructed with state-of-the-art design and materials, or when the property is a specialty or special purpose property. The relevance of the cost approach is also a function of market supply and demand as of the valuation date, which will determine whether the cost of new property can be supported by the market or whether excess supply has diminished the property's ability to earn a return on and of invested capital.

The cost approach starts with a market-based estimate of the cost necessary to replace or reproduce the improvements associated with the Developments and deduce the appropriate deterioration and obsolescence to arrive at the market value of the improvements. The cost new and the estimates of depreciation are market-based and account for physical deterioration as well as functional and external obsolescence.

Reproduction/Replacement Cost Primary Methods

The calculation of the cost new for the Developments can be developed using multiple approaches and techniques to arrive at an opinion of cost new. The selection of the method and technique to apply will vary depending on the type and age of the subject, availability of data, and the purpose of the appraisal. There are two types of cost new for property improvements.

- **Replacement Cost New** represents the cost to construct assets with similar utility to the subject using modern materials and current standards and design.

- **Reproduction Cost New** is the estimate of cost to construct an exact duplicate of the assets being appraised and will include any obsolescence found in the subject.

In developing the cost new, the method utilized may depend on the availability of original cost records or reliable sources of known cost data. Original cost records may be utilized to trend the data to current market conditions. Absent of this data there are three primary methods of estimating the cost new. Each method is considered when choosing the appropriate method for a subject property. These methods include the comparative-unit method, the unit-in-place method, and the quantity survey method used for both reproduction and replacement. The methods, including cost index trending, are each generally defined by *The Appraisal of Real Estate, 15th ed.* *(Appraisal Institute)* as follows:

- ***Cost Index Trending:*** Cost manuals and electronic databases periodically update the cost index tables that reflect changes in the cost of construction over a period of years. Cost indices can be used to convert a known cost as of a past date into a current cost estimate. Sometimes cost index tables can be used to adjust costs for different geographic areas. Cost index trending is also useful for estimating the current cost of one-of-a-kind items when standard costs are not available. However, there are practical limitations in applying this procedure because the reliability of the current cost indication tends to decrease as the time span increases.[37]

- *Comparative-Unit Method:* The comparative-unit method is used to derive a cost estimate measured in dollars (or some other currency) per unit of area. The method employs the known costs of similar structures adjusted for market conditions and physical differences. Indirect costs may be included in the unit cost or computed separately. If the comparable properties and the subject property are in different markets, an appraiser may need to make an adjustment for location.[38]

- *Unit-in-Place Method:* In the unit-in-place method (also known as the segregated cost method), individual unit costs for various building components are applied to the various subcomponents in the structure or to linear, area, volume, or other appropriate measures of these components. Using this method, appraisers compute a unit cost based on the actual quantity of materials used plus the labor of assembly required for each unit of area.[39]

- *Quantity Survey Method:* The most comprehensive and accurate method of cost estimating is the quantity survey method. A quantity survey reflects the quantity and quality of all materials used in the construction of an improvement and all categories of labor required. Unit costs are applied to these figures to arrive at a total cost estimate for materials and labor. Then the contractor adds a margin for contingencies, overhead, and profit.[40]

The ability to utilize a particular approach is a function of the type of property and the availability of information on which to develop the approach and reach a conclusion. For this analysis we utilize the Comparative-Unit Method.

Reproduction Cost New – Quantity Survey

To develop the cost new for the Developments, a quantity survey has been performed previously for the Developments, which details the take-off of all of the primary components of construction of the plant. Added to the costs of the detailed take-offs are indirect costs, profits, overheads, owner's tasks, engineering, permitting, insurance, taxes during construction, and interest during construction, all commonly known as indirect (soft) costs added to the direct (hard) costs of construction. The detailed quantity take-offs were performed using the license drawings of the dams and power houses which provide plans and elevations of the as-constructed facilities. In addition, GRH and/or its predecessors have provided detailed documentation, plans, and specifications of equipment, structures and improvements, and electrical one-line and three-line diagrams.

The unit quantities developed in the quantity survey take-off tables are then costed using the nationally recognized RSMeans (Means) cost manuals. These cost manuals are publicly available through RSMeans for purchase and follow the CSI (Construction Specifications Institute) number reporting

[37] Appraisal Institute. *"The Appraisal of Real Estate, 14th ed."* 2013, pp. 583-584.
[38] *Id.* at p. 584.
[39] *Id.* at p. 590.
[40] *Id.* at p. 594.

format for various types of construction material, labor, and categories. The numbering system used in RSMeans (which is the same in all of the RSMeans books) is provided in the quantity survey take-off table. The unit costs new are provided such that the quantities are multiplied times the unit cost to arrive at a total cost new.

The quantity survey analyses, performed in 2010, were then trended to the valuation date of April 1, 2023.

Table 9 summarizes the direct and indirect costs used to estimate the reproduction costs new for the Developments, as of April 1, 2023.

Table 9: Reproduction Cost New

	A	B	C	D	E	F
Row	Facility	Estimated Direct RCN (2010)	Estimated Indirect RCN (2010)	Total Estimated RCN (2010)	Handy-Whitman Index Factor as of 7/1/2022[1]	Total Trended Estimated RCN
				[A+B]		[CxD] (Rounded)
1	Comerford	$458,700,892	$261,459,508	$720,160,400	1.43	$1,029,600,000
2	McIndoe	$36,625,887	$22,016,756	$58,642,643	1.43	$83,800,000

[1] HWI Factor Calculated by dividing 1/1/2023 Total Hydraulic Production Plant Index of 702 by the 1/1/2010 index of 491

Depreciation

The three basic types of depreciation recognized, evaluated, and applied in the cost approach are physical depreciation, functional and external obsolescence. The following subsections summarize the application of depreciation to the Developments.

Physical Depreciation

Physical Depreciation, or the day-to-day wear and tear of the Station, is estimated using the age-life method. The ratio of age to estimated useful life is calculated using the useful physical life of the improvement as the denominator and the effective age of the improvement as the numerator.

The first step of the equation is to determine the effective age of the property. In order to complete the equation, an estimate of the expected useful physical life of the Station was made. Although a common term, "life" may have several definitions when used for appraisal purposes. There is the "economic life" derived from paired sales of property and other market influences, a pure "physical life" which would describe the period of time an item may exist, and "useful physical life" which is the period of time that an item is expected to be able to perform its duties. For the purposes of this assignment, the appraiser has considered the economic life of the generating technologies at the Station.

Hydroelectric plants have proven to be long-lived assets, with many dams, turbines, and buildings built in the 1900s to 1920s still in use today. Other short-lived assets are routinely maintained, as it is required to maintain a level of reliability that is conducive to the owner's obligation to ISO-NE to be available for power generation and capacity. Many facilities in New England are operating under their second or third license extension. Additionally, the Developments have undergone numerous upgrades and overhauls; the major components like the dam, turbines, and generators have substantial remaining economic life. The Developments have gone through the process of relicensing through FERC, indicating that the Developments is projected to be functionally capable of operation for at least an additional 20 years at a very high level of safety and reliability. Although the Developments are nearly 100 years old, its remaining physical and economic life is substantial due to the consistent maintenance, capital improvement, inspection, and preservation of the dam's integrity, as well as its potential for relicensing.

For the Developments, the effective age can be estimated by observing the current condition of the Station, the effects of ongoing maintenance and capital improvements, dam safety reports, recent upgrades, as well as the economic analyses performed and necessary in support of the relicensing application. Based on the recent license application, which implies the Station has no significant deficiencies, deferred maintenance, or safety issues, we estimate the Developments have an economic life of at least two license periods of 40 years each. The estimation of the effective age of the stations is based on our observations at the time of past site inspections, consideration of past or recent upgrades and improvements, and estimations of required future upgrades and improvements. All of which contribute to Facilities' reliability and profitability. Based on these considerations we estimate the effective age of the Developments to be approximately 40 years, or 50% depreciated. Therefore, the reproduction cost new less physical depreciation is as follows:

Table 10: Reproduction Cost New Less Depreciation

	A	B	C
Row	Facility	Trended RCN	Calculated RCNLD [RCN*(40/80)]
1	Comerford	$1,029,600,000	$514,800,000
2	McIndoe	$83,800,000	$41,900,000

Functional Obsolescence

Functional Obsolescence is a loss in value that may be caused by a deficiency or a superadequacy. Some forms of functional obsolescence are curable, while others are incurable. "Functional obsolescence, which may be curable or incurable, can be caused by a deficiency—that is, some aspect of the subject property is below standard in respect to market norms. It can also be caused by a superadequacy—that is, some aspect of the subject Property exceeds market norms." [41]

The Developments are designed to maximally utilize the available resource under the requirements and restrictions set forth by the licenses. Therefore, no functional obsolescence is attributed to the Developments.

[41] Appraisal Institute. "The Appraisal of Real Estate, 14th ed.". 2013, p. 624

Economic Obsolescence

The final element of obsolescence to be considered in the cost approach is *external* or *economic obsolescence*. "External obsolescence can be temporary or permanent. For example, value loss due to an oversupplied market may be regained when the excess supply is absorbed, and the market works its way back to equilibrium. In contrast, the value loss due to proximity to an environmental disaster may be permanent." [42] External obsolescence usually carries a market-wide effect and influences a whole class of properties, rather than just a single property. External obsolescence may affect only the subject property when its cause is location, e.g., proximity to negative environmental factors or the absence of zoning and land use controls.

The external obsolescence associated with the Developments was analyzed using the income shortfall method. The income shortfall method compares the cost new less physical deterioration and functional obsolescence with the estimated net present value (NPV) of future cash flows to determine if the remaining cash flows are sufficient to support this value. If the cash flows are insufficient to support the cost new less physical deterioration and functional obsolescence, a deduction is made for obsolescence. If the cash flows exceed this figure, the obsolescence is still deducted but results in a reversal of other forms of depreciation due to the earning potential of each facility.

This measure of economic obsolescence is most often used in the valuation of this type of property by using either the sales of similar property or the income capitalization approach. The income approach for the Developments indicates a value less than the cost new less depreciation, indicating some level of economic obsolescence. This is not atypical of hydroelectric facilities, as most were constructed during a time where heavy civil works projects were much more cost effective to construct; they could not be built today with the same level of economic payback expected by investors. Economic obsolescence is analyzed and accounted for in the reconciliation section of this report.

Land Value Estimate

The total land value that we assume for the land and land rights associated with the Developments in Barnet, VT is $4,347,400 for Comerford and $1,225,400 for McIndoe. The total land value that we assume for the land and land rights associated with the Developments in Monroe, NH is shown in Table 11. Of the total, $1,151,700 is associated with Comerford and $421,100 is associated with McIndoe.

[42] Appraisal Institute. "The Appraisal of Real Estate, 14th ed.". 2013, p. 632

Table 11: Land Assessments

	A	B	C
Row	**Parcel ID**	**Acres**	**Land Value**
1	***Great River Hydro - Land Values in Monroe, NH***		
2	R04-003	*1.1*	$3,900
3	R04-004	*13*	$21,600
4	R08-006	*38.2*	$90,900
5	R08-007	*10*	$17,000
6	R08-008	*65*	$42,100
7	R11-011	*86*	$240,900
8	R11-012	*81*	$189,900
9	R11-013	*5*	$250,000
10	R11-014	*94.6*	$161,600
11	R11-022	*28*	$87,200
12	R11-023	*14*	$46,600
13	U02-048	*17.3*	$56,900
14	U03-008	*0.147*	$500
15	U03-009	5.2	$251,000
16	U03-010	*1.3*	$4,600
17	U03-011	*0.15*	$500
18	U03-012	*0.33*	$41,300
19	U03-013	*20.58*	$66,300
20	***Total Land & Flowage Rights:***	***480.91***	**$1,572,800**

Summary of Value Estimate Using the Cost Approach

Table 12 summarizes the final indicated value of the Cost Approach, which includes the reproduction cost new less physical and functional obsolescence, plus the value of the land as discussed previously. Economic obsolescence will be evaluated and applied during the reconciliation of value in this report.

Table 12: Final Indicated Value of Cost Approach

	A	B	C	D
Row	**Facility**	**Reproduction Cost New Less Depreciation**	**Land and Land Rights**	**Indicated Value of Cost Approach**
1	Comerford	$514,800,000	$1,151,700	**$515,951,700**
2	McIndoe	$41,900,000	$421,100	**$42,321,100**

SALES COMPARISON APPROACH

Introduction

In the sales comparison approach, the appraiser develops an opinion of value by analyzing closed sales, listings, and pending sales of properties that are similar to the subject property. The comparative techniques of analysis applied in the sales comparison approach are fundamental to the valuation process. Estimates of market rent, expenses, land value, cost, depreciation, and other value parameters may be derived in the other approaches to value using comparative techniques. Similarly, in applying the sales comparison approach, appraisers often analyze conclusions derived in the other approaches to determine the adjustments to be made to the comparable sale.

The sales comparison approach is most applicable in an active market where the prices paid serve as accurate indicators of the most probable selling price of the property as of the valuation date. The analyses applied in the sales comparison approach are fundamental in the appraisal process and develop market-based estimates of comparison that can then be used to estimate the market values of the Developments. We searched the marketplace for recent sales which would provide reliable estimates of unit prices that could be applied to the Developments. The characteristics that influenced the appraiser's opinion of comparability include the location of the asset(s) that comprise the transactions, motivation of buyers and sellers, financial conditions surrounding the sale, supply and demand in the region at the time, and the physical and economic characteristics of the assets that comprise the property being sold.

The sales comparison approach analysis often results in a unit price that can be applied to a property based on a certain physical attribute such as size, output, etc. For hydroelectric facilities, these unit prices are typically developed by dividing the reported sale price by either the rated or nameplate capacity ($/kW) or by the reported annual generation ($/kWh-yr.). Used as a rule of thumb, the unitizing of the price per capacity can result in relatively consistent price benchmarks but it fails to consider the variance in capacity factors and generation efficiencies for different properties. Unitizing the price per kWh-yr. of annual generation considers a property's capacity factor and its relative efficiency. In analyzing the comparable sales data of recent years, we have seen that sale prices per kWh-yr. have provided a more reliable statistical cluster than using sale prices per rated or nameplate capacity. Therefore, the appraiser has unitized the sale prices of the comparable sales into $/kWh-yr. for this report.

Comparable Sales

Our ongoing search for hydroelectric sales in the region has produced nine comparable sales which we believe are indicative of the market. These nine sales are shown and summarized below in Table 13.

Table 13: Comparable Hydroelectric Sales

		A	B	C	D	E	F	G	H	I	J
Sale #	GES Sale #	Selling Entity	Purchasing Entity	Plants	Date of Agreement	Sale Date	Sale Price	Installed Capacity (MW)	Average Annual Generation of Units Sold (MWh)	Sale Price per KW (F÷(Gx1,000))	Sale Price per KWh-yr. (F÷(Hx1,000))
1	775	Verso Androscogoggin Power, LLC	Eagle Creek Renewable Energy	Riley, Jay, Otis, Livermore	1/6/2016	3/29/2016	$62,000,000	30.05	140,399	$2,063	$0.44
2	679	Northbrook, NY sub of Chicago Holdings, indirect sub of Veresen	Glen Park Holdco sub of Restless Hydro, LLC sub of I Squared Capital Private equity Investment Manager	Glen Park	5/24/2016	8/1/2016	$61,000,000	32.65	146,924	$1,868	$0.42
3	992	Brown Bear II Hydro Inc.	Eagle Creek Renewable Energy	Worumbo	UNK	11/21/2016	$60,000,000	19.40	97,452	$3,093	$0.62
4	1164	Enel Green Power North America	Green Mountain Power	Salmon Falls, Rollinsford, Lower Valley, Woodsville, Mascoma, Somersworth, EHC, Kelly's, Dewey's Mills, Barnet, Ottaquechee, Newbury	July-16 / Jan-17	Jan-17/ May-17	$16,200,000	13.84	34,796	$1,171	$0.47
5	988	TransCanada Hydro Northeast Inc.	Great River Hydro NE, LLC	Bellows Falls, Comerford, McIndoes, Moore, Deerfield Nos. 2, 3, 4, 5, Harriman, Searsburg, Sherman, Vernon, Wilder	11/1/2016	4/19/2017	$1,065,000,000	522.87	1,543,523	$2,037	$0.69
6	1129	Madison Paper Industries	Eagle Creek Madison Hydro, LLC	Anson, Abenaki	4/17/2017	7/31/2017	$65,300,000	28.92	142,226	$2,258	$0.46
7	1385	I Squared Capital Advisors LLC.	Intergex Renewable Energy, Inc.	Curtis, Palmer Falls	8/17/2021	10/25/2021	$321,556,000	58.80	329,915	$5,469	$0.97
8	1287	AEP Generation Resources Inc.	Eagle Creek Racine Hydro, LLC	Racine	2/1/2021	12/30/2021	$88,000,000	47.50	171,422	$1,853	$0.51
9	1419	Great River Hydro Finance, LLC	HQI US Holding LLC	Bellows Falls, Comerford, McIndoes, Moore, Deerfield Nos. 2, 3, 4, 5, Harriman, Searsburg, Sherman, Vernon, Wilder	9/29/2022	2/10/2023	$2,250,000,000	568.70	1,438,125	$3,956	$1.56
										Average all Sales	$0.68
										Median all Sales	$0.51
										Selected Indicator of Value	**$0.60**

Comparable Sale 1: In January of 2016, Verso Androscoggin Power, LLC and Verso Maine Power Holdings, LLC agreed to sell four hydroelectric facilities to Eagle Creek Renewable Energy, LLC for $62,000,000. These facilities, totaling 30 MW, provided power to Verso's paper mill, and each operate under a 50-year license valid through 2048. Eagle Creek Renewable Energy, LLC, owns and operates 58 hydroelectric facilities in the United States totaling 638 MW of capacity. The portfolio, located on the Androscoggin River in Maine, produces an average of 140,399 MWh per year, imputing a purchase price of $0.44/kWh-yr.

Comparable Sale 2: In mid-2016, Fort Chicago Holdings II, U.S., LLC sold its last U.S. hydroelectric facility, Glen Park, to Glen Park Hydro, LLC (Cube Hydro), as part of Fort Chicago's strategy to exit its power generation business. Glen Park Hydro, LLC was formed specifically for the transaction, and is ultimately controlled by I Squared Capital (Cube Hydro), a private equity investment manager with hydroelectric investments totaling 159 MW. Glen Park is a 32.65 MW run-of-the-river hydroelectric facility on the Black River in Glen Park, NY. Glen Park has a five-year average generation of 146,924 MWh, which at a sales price of $61 million, yields a value of $0.42/kWh-yr.

In June 2019, Ontario Generation announced that it had agreed to purchase this facility as part of a portfolio of plants, totaling 370 MW of capacity, owned by Cube Hydro. This sale closed in October 2019 and is discussed in the subsequent section below.

Comparable Sale 3: In late 2016, Eagle Creek Renewable Energy closed on the acquisition of the Worumbo Hydroelectric Facility from Brown Bear II Hydro Holdings, LLC. Worumbo Hydro consists of 19.4 MW of capacity and produces approximately 97 million kWh/yr. To date, Eagle Creek owns and operates six facilities, including Worumbo, on the Androscoggin and Little Androscoggin Rivers. Located in Lisbon, ME, the facility sold for $60,000,000, or $0.62/kWh-yr.

Comparable Sale 4: In mid-2017, Green Mountain Power Corporation (GMP) closed on its acquisition of 12 hydroelectric facilities from Enel Green Power North America. The plants are located in New Hampshire, Vermont, and Maine, and make up a total of 13.84 MW, with Dewey's Mill being the largest at 2.78 MW.

A final purchase price of $16,200,000 was heavily examined by the Vermont PUC, as many of the plants were outside of GMP's service area and required additional regulatory oversight. During the VT PUC hearing, GMP estimated the generation that would be gained in the transaction to total 42,022,000 kWh.

The year following the sale, the 12 plants generated just 27,517,000 kWh, which yields a realized price of $0.59/kWh-yr. This actual generation is reflective of the level of service and construction necessary to realistically produce the electricity that GMP informed the VT PUC would be realized. Upon closing the acquisition, GMP immediately began maintenance and repairs. This work is ongoing, indicating the level of deferred maintenance that should be considered in the sales analysis.

Our analysis calculated a 10-year historic average generation of 34,796,000 kWh, imputing to a sales price of $0.47/kWh-yr. We believe that $0.47kWh-yr. best represents the total value the plants could provide at the time of the sale.

Comparable Sale 5: On March 17, 2016, TransCanada (TC) of Calgary, Alberta announced its intention to acquire the Columbia Pipeline Group for approximately $13 billion USD. As part of this strategy, the company also announced that it would sell its U.S. Northeast power assets, which include assets owned by TransCanada Hydro Northeast, Inc. On November 1, 2016, TransCanada and ArcLight Capital Partners announced that ArcLight's affiliate, Great River Hydro signed a "…definitive agreement to acquire TransCanada's New England hydroelectric power portfolio." According to a TC press release, ArcLight agreed to pay $1.065 billion for the hydro assets. According to TC, the $1.065 billion selling price does not include TC's power marketing business, which is expected to be sold at a later date. A 5-year average generation of 1,388,273 MWh yields an indicated sales price of $0.77/kWh-yr., while a 10-year average generation of 1,543,523 MWh yields an indicated sales price of $0.69/kWh-yr.

Comparable Sale 6: In mid-2017, Madison Paper Industries sold interest in multiple properties and entities to Eagle Creek Madison Hydro, LLC (a wholly owned subsidiary of Eagle Creek Renewable Energy, LLC) for a total purchase price of $69,300,000. This transaction included the sale of the Anson and Abenaki hydroelectric facilities, as well as Madison Paper Industries' interests in the headwaters, including Kennebec Water Power Company and the Brassau Project (P-2615). The consideration allocated to the Anson and Abenaki facilities is $17,000,000 and $48,300,000, respectively totaling $65,300,000. The Anson Hydroelectric Project is a run-of-river generating facility located at the site of the former Madison Paper Mill on the Kennebec River consisting of five turbine-generating units with a total installed capacity of 9 MW. The Anson Hydroelectric Project is a run-of-river generating facility located at the site of the former Madison Paper Mill on the Kennebec River consisting of eight turbine-generating units with a total installed capacity of 19.917 MW. After adjusting the sale to account for the Kennebec Water Power Company and Brassau, the indicated sales price was $0.46/kWh-yr.

Comparable Sale 7: In October of 2021, Innergex HQI USA, LLC closed on the purchase of the Curtis Palmer Development from affiliates of I Squared Capital Advisors for a reported sales price of $321,556,000. The project consists of two developments, Curtis and Palmer Falls, and is located on the Hudson River in Corinth, NY. The project is operated in cooperation with an extensive storage system located in the headwaters of the Hudson River. All of the output of the Curtis Palmer facility is sold to Niagara Mohawk Power Corporation pursuant to a long-term amended and restated power purchase agreement dated January 5, 1995, and accepted for filing by FERC on March 14, 1995. The agreement includes the sale of energy, RECs, and capacity and expires upon the earlier of either December 31, 2027, or the delivery of cumulative 10,000 GWh (expected in 2026). Following the expiration of the PPA, it is expected that the project will sell energy, RECs, and capacity in the NYISO market. The projects' combined 10-year average generation is 329,915 MWh, which indicates a sales price of $0.97/kWh-yr.

Comparable Sale 8: In 2021, Ontario Power Generation Inc, through its subsidiary Eagle Creek Racine Hydro, LLC acquired the Racine Hydroelectric Project from AEP Generation Resource Inc. Racine is a 47.5 MW run-of-river project on the Ohio River in Meigs County, OH. The original 50-year federal license was issued in December of 1973. At the time of the sale, the project was in the process of being relicensed. The consideration totaled $88,000,000, which implies a sales price per kWh of $0.51/kWh-yr.

Comparable Sale 9: In September of 2022, Great River Hydro NE, LLC (Great River) agreed to sell the portfolio of New England hydroelectric projects that it had acquired from TransCanada in 2016 to a subsidiary of Hydro-Quebec (HQ). The summer rating for the combined portfolio totaled 568.7 MW. The sales price is reported to be $2.250 billion, including the assumption of $750 million in debt. This transaction implies an appreciation in the value of the assets of more than $1 billion in six years. Based on the 10-year average generation for the portfolio, this transaction yields a value indicator of $1.56 per kWh-yr.

Additional Sales Discussion and Other Probative Sales Considered for Valuation[43]

In addition to the nine primary comparable sales considered, there are several other transactions that are probative and/or worthy of discussion. Table 14 is a summary of these sales. Following Table 14 is a discussion of each transaction.

[43] USPAP Advisory Opinion 34

Table 14: Probative Hydroelectric Sales

		A	B	C	D	E	F	G	H	I
Sale #	GES Sale #	Selling Entity	Purchasing Entity	Plants	Sale Date	Sale Price	Installed Capacity (MW)	Average Annual Generation of Units Sold (MWh)	Sale Price per KW (E÷(Fx1,000))	Sale Price per KWh-yr. (E÷(Gx1,000))
1		PSNH (Eversource Energy)	Hull Street (Central Rivers)	Amoskeag, Smith, Garvins, Ayers Island, Eastman Falls, Jackman, Gorham, Hooksett, Canaan	8/1/2018	$83,000,000	68.20	345,922	$1,217	$0.24
2	1163	Cube Hydro Partners and Helix Partners	Ontario Power Generation	19 Hydro Projects	10/7/2019	$1,120,000,000	369.40	1,363,621	$3,032	$0.82
3	1128	Eagle Creek Renewable Energy, LLC	Ontario Power Generation	63 Small Facilities	11/27/2018	$512,000,000	216.00	UNK	$2,370	N/A
4	1420	Hull Street (Central Rivers)	LS Power Equity Partners IV	45 Hydro Projects	TBD - 2023	TBD	330.00	TBD	TBD	TBD

Probative Sale 1: A portfolio of nine hydroelectric facilities in New Hampshire sold in August of 2018. On June 10, 2015, Public Service Company of New Hampshire (PSNH) entered into a legislatively mandated restructuring and rate stabilization agreement with the New Hampshire Public Utilities Commission (NHPUC). This agreement required PSNH to sell all its power plants, including nine small to medium sized hydroelectric plants. This agreement was amended on January 26, 2016, and further subjected to a partial litigation settlement. The final order was issued on July 1, 2016, which initiated the sale process.

The amount of capital investment under contest and settled in this docket through the divestiture of all powerplants was over $400 million. The forced sale of PSNH's generation assets was deemed by the NHPUC to be in the best public interest and was commenced through a controlled and legislated competitive solicitation by JP Morgan Securities. PSNH complied with the findings which benefited it with a guaranteed settlement for the return of its investment in the pollution control devices installed at the Merrimack Coal Fired Power Station in Bow, NH, which facilities were mandated under previous state legislation. The final disposition of hydroelectric plants was approved in the NHPUC Order 26,080 on November 29, 2017. Hull Street Energy Hydro LLC submitted the winning bid for the hydro facilities and was approved to purchase the assets. The transaction closed in August 2018.

The auction and the purchase were put on a fast track with required closing dates. The entire bidding and buying community knew that this was a forced sale. There were numerous stipulations regarding employee benefits, continuance of service, and long-term liabilities that were required of the buyers. As a result, findings presented in the approval order determined that the sale was not arm's length or indicative of market value. The order stated "…the total sales price and any allocated prices for the generation facilities contained in the Hydro PSA being approved by this Order is not a statement of fair market value of those facilities for any state and/or local property tax purposes…" Therefore, we recognize but do not consider this transaction as a comparable sale for this analysis, as the circumstances do not reflect a typically motivated seller and reflect considerations atypical for a transaction indicative of fair market value.

Probative Sale 2: In October of 2019, Ontario Power Generation (OPG), a provincially owned Crown corporation of Ontario, Canada, closed on the acquisition of Cube Hydro Partners and Helix Partners for $1.12 billion USD. Collectively the acquisition includes 19 hydroelectric plants in 5 states with a cumulative average historic generation of 1,363,621 MWh annually, indicating a sales price of $0.82/kWh-yr. Note that OPG is provincially owned (i.e., government owned) and is able to finance 100% of the purchase through its corporate public debt program. This debt is assumed to be 100% tax exempt.

Probative Sale 3: In August of 2018, it was announced that Eagle Creek Renewable Energy, LLC, which owns and operates 76 hydroelectric facilities totaling approximately 216 MW, would be purchased by Ontario Power Generation (OPG), a provincially owned Crown corporation of Ontario, Canada. The total consideration is believed to be approximately $512 million, which would indicate a sales price of $2,370/KW-capacity.

Probative Sale 4: In November of 2022, Hull Street Capital reached an agreement whereby affiliates of LS Power Equity Partners IV would acquire its 45-project hydroelectric portfolio, totaling nearly 330 MW. The majority of the projects are located in New England and New York and include the

New Hampshire facilities included in the PSNH Divestiture, acquired by Hull Street in 2018. The terms of the transaction have not been published.

Sales Comparison Approach Analysis

To determine an indicated value from the sales comparison approach based on its kWh-yr. generation, the first step is to determine the amount of energy the Developments will produce and subsequently sell to the market or buyer. Generation is determined by analyzing the historic generation of the plant. Based on information reported to various administrations, the Developments have a selected average of: **340,355 MWh** for the Comerford Station and **43,617 MWh** for McIndoe Station per year over the last 13 years (Refer to Table 2).

Indicated Value of Sales Comparison Approach

We have compared the Developments to the average comparable sales price of $0.68/kWh-yr. (mean sales price of $0.51/kWh-yr.) The Developments have unique beneficial attributes which are a result of both the original design and the improvements made by the Owner which meet or exceed that of the average hydroelectric plants that transact regularly within the regional market. As the primary purpose of the Developments is to create electricity and income for its owner, these benefits are best quantified by their impact on the earning potential of the Developments as it compares to the average hydro in the region. While no direct adjustments were made to the sales themselves, we consider these incremental benefits of the unique attributes of the Developments in the reconciliation of this report.

Additionally, probative and historic sales of hydroelectric facilities would indicate a strong and increasing market trend and sentiment towards hydroelectric technology in the renewable energy sector. We therefore reconcile to an indicated value of $0.60/kWh-yr., recognizing both the median and mean sales prices from the comparable sales analyzed. However, as more probative sales occur, the selected indication of value may be considered a conservative estimate. This is supported by the sale of the Developments in early 2022 for approximately $1.56/kWh-yr. or nearly three times the selected indication of value.

Therefore, the indicated value of the Sales Comparison Approach as of April 1, 2023 is:

- Comerford Station: **$204,200,000** (rounded) (340,355,000 kWhs x $0.60)
- McIndoe Station: **$26,150,000** (rounded) (43,617,000 kWhs x $0.60)

INCOME CAPITALIZATION APPROACH

Introduction

The income capitalization approach derives a value estimate based on the total present worth of all anticipated future benefits that arise from ownership of the property. The income approach is considered to be, in the appropriate circumstances, the best means of estimating the value of an income-producing property. Implicit in this approach is consideration of the amount and probability of receiving future income from operation of the property.

The basic concept behind the income approach may be represented by the following formula:

$$Value\ (V) = \frac{Income\ (I)}{Rate\ (R)}$$

Value (V) is a direct function of the future Income (I) and an inverse function of the comparative risk of the investment which is reflected by the cost of capital or Capitalization Rate (R). This basic formula can be used to estimate the value of any given property by capitalizing the anticipated future cash flows by the perceived risk associated with receiving the cash flow as compared with other investments available in the market.

The critical elements of the income capitalization approach are the reliability of the anticipated future cash flows and the cost of capital associated with the particular investment.

Methods used to capitalize future income include the "Direct" and "Yield" Capitalization approaches. Each of the approaches is premised on the relationship described above, between value, income, and perceived risk. The approaches are each defined as follows:

- ***Direct Capitalization*** *is a method used in the income capitalization approach to convert a single year's income expectancy into a value indication. This conversion is accomplished in one step, by dividing the net operating income estimate by an appropriate income rate.*[44]

- ***Yield Capitalization*** *is used to convert future benefits, typically a periodic income stream and reversion, into present value by discounting each future benefit at an appropriate rate or by applying an overall rate (developed using one of the yield capitalization methods) that explicitly reflects the investment's income pattern, change in value, and yield rate.*[45]

In this valuation, we will utilize a Yield Capitalization approach to estimate the value of the Developments, as this is the approach most often used to estimate the value of merchant generators by market participants. Yield Capitalization, by way of a discounted cash flow, can be utilized to account for changes in the revenue, expenses, depreciation, etc. over the course of a selected period (as opposed to direct capitalization which assumes stable cash flows). As discussed previously, cash

[44] Appraisal Institute. "*The Appraisal of Real Estate, 14th ed.*". 2013, pp. 491.
[45] Appraisal Institute. "*The Appraisal of Real Estate, 14th ed.*". 2013, pp. 510.

flows are affected in the future by differing electricity prices, capacity prices, accelerated depreciation, etc. Yield Capitalization best deals with the effect of these changes.

Discounted Cash Flow

Discounted Cash Flow (DCF) analysis is a procedure in which a yield rate is applied to a set of income streams and a reversion to determine whether the investment property will produce a required yield given a known acquisition price. If the rate of return is known, DCF analysis can be used to solve for the present value of the property. If the property's purchase price is known, DCF analysis can be applied to find the rate of return.[46]

For the purpose of this report, we have determined an appropriate rate of return for the Developments. We have employed this rate of return in our calculations of a weighted average cost of capital/discount rate. Since we have estimated a known rate of return, we are employing the DCF Analysis to solve for the present value of the Developments. Please refer to Table 15 and Table 19 for our DCF inputs, including our discount rate assumption. Where referenced, the selected rate of inflation when applied is 3% annually.

Revenue

Generation

To determine revenue, the first step is to determine the amount of energy and capacity the Developments will produce and subsequently sell to the market or buyer. As discussed previously in this report, we utilize 13-year averages as the going forward generation for the Developments. Based on information provided in previous assignments, the Developments are able to achieve a better on-peak/off-peak ratio than average due to the peaking ability. A typical run-of-river hydro will achieve 47% of its power production during on-peak hours, which is representative of how many on-peak hours occur during a year.

Energy and Capacity

The Developments can sell both their energy and capacity, as well as any Renewable Energy Certificates (RECs). As discussed in the Market Analysis section of this report, forecasts were developed and utilized to determine the going forward energy and capacity price forecast based on the forecasted relationship of natural gas to energy, as well as the likelihood of the capacity price recovering to an attractive rate (as represented by the CONE) necessary to spur new development of capacity in New England. As discussed previously, DCFs were analyzed based on three scenarios: a low-capacity scenario, a high-capacity scenario, and a historic capacity scenario. Capacity payment rates for the first four years of the DCF are the forward capacity auction (FCA) prices and auction results, weighted to account for the fact that the auctions run from June to May. For all other DCF years we have relied on our adjusted forecasted FCA pricing as described in the Market Analysis section of this report.

[46] Appraisal Institute. "*The Appraisal of Real Estate, 14th ed.*". 2013, pp. 530

The capacity payments for the Developments in our DCF are based on the ISO "qualified capacity" as reported by ISO-NE to FERC for any given year.

Ancillary Services

[redacted]

Renewable Energy Certificates (RECs)

REC revenue is available to the Developments, and is not considered in the DCF analyses, as discussed previously.

Expenses

The Developments incur three primary categories of expenses: operating and maintenance, administrative and general, and capital expenditures.

Operation and Maintenance Expenses (O&M) & Administrative and General Expenses (A&G)

The historic operating and maintenance expenses were provided by the Company in previous assignments. [redacted] We perform an expense study of hydroelectric projects across the eastern part of the country. This study yields an average expense for a plant the size of the Developments of approximately $3 million annually, combined. [redacted]

Capital Expenditures (CapEx)

Historic CapEx and CapEx projections were provided by the Owner, [redacted] We therefore utilize 1% of the total valuation annually in CapEx, adjusted for inflation. This amounts to approximately $1,600,000 to $2,000,000 per year in CapEx for period 1 of the DCF analyses.

Property Taxes

Property taxes are included as an adder to the discount rate below.

Discount Rate

Discount Rate

The discount rate selected was based on a review of the market metrics from our guideline companies. Based on the published after-tax equity rates of 11 guideline independent power producers and 5 regulated utilities, the average after-tax equity rate realized in 2022 was 9.0%. The 10-year average (2013-2022) after-tax equity rate was 8.6%. Ultimately, the 10-year average after-tax equity rate of 8.6% was selected for the DCF analysis. The debt rate was selected based on current BBB rated corporate bond yields of 5.5%. A 60%/40% debt to equity ratio was selected, yielding a total Weighted Average Cost of Capital (WACC), or discount rate, of 5.9%. Property taxes are then adjusted for income tax benefits and added to this discount rate.

Discount Factor and Terminal Capitalization Rate

The discount factor is the present value (for any given year of the DCF) of the discount rate. The discount factor is applied to the after-tax net cash flow which results in the discounted cash flow.

Hydroelectric plants are designed to last between 100-150 years. They utilize public resources and are licensed to do so by the Federal Energy Regulatory Commission. These licenses are issued for 30 to 50 years. Many sites in the United States are beginning their third license renewals. When one values hydroelectric plants using the income approach and the discounted cash flow methodology, the discounting period of 20 years for example is so short that there is significant residual value at the end of the discount cash flow term. The property will be maintained to top condition and will be available as a valuable asset to the owner at the end of the term. It is therefore necessary to revert the future value of the plant at the end of the DCF to a present value today of the plant and add that reversionary value to the present value of the stream of cash flow. This is essentially the same as preparing a 40-to-50-year discounted cash flow. The capitalization rate used to value the Developments at the end of the discounting period is the same capitalization rate used today if the risk profile of the Developments has not changed, which it has not. It is then discounted back at the same discount rate as the stream of cash flows earned by the plant. This is a common methodology in yield capitalization of income producing property.

Summary of DCF and Value Estimate

The previously described assumptions that relate to revenue and expenses that are applicable and appropriate to the Developments have been incorporated into the DCF. These assumptions and the DCF calculations are shown in Table 15 through Table 22.

Based on the analysis of three revenue scenarios, we believe the indicated value by the income approach for the Developments to be weighted evenly between the three scenarios, as it is most likely that the future capacity market will reflect some sort of blend of the assumptions made under each scenario. We therefore conclude an indicated value of **$294,000,000 for the Comerford Development and $21,300,000 for the McIndoe Development.**

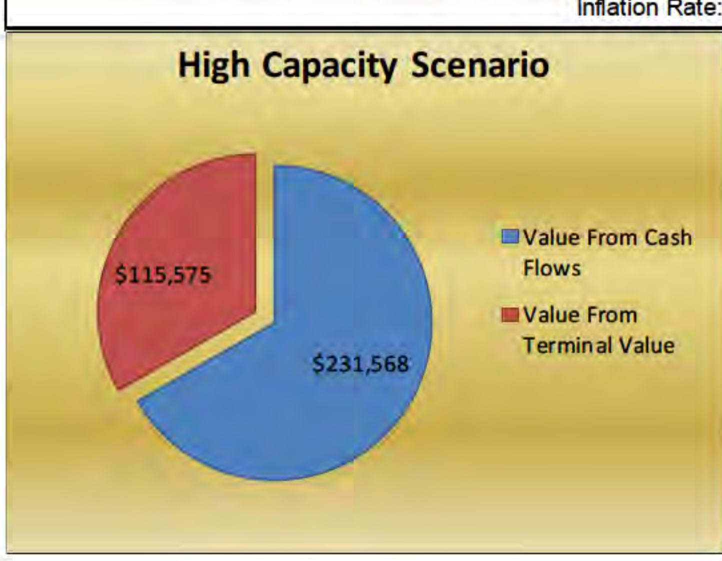
Table 15: Comerford Station DCF Inputs

Yellow Highlighted Cells With Red Font are INPUT cells				
Plant Name:	**Comerford**			
Valuation Date:	**April**	**1**	**2023**	
High Capacity Price Scenario				
Estimated Plant Value:	**$347,100,000**			
Estimated Plant Value ($/kWh-yr):	**$1.02**			
Low Capacity Price Scenario				
Estimated Plant Value:	**$263,500,000**			
Estimated Plant Value ($/kWh-yr):	**$0.77**			
Historic Capacity Price Scenario				
Estimated Plant Value:	**$271,300,000**			
Estimated Plant Value ($/kWh-yr):	**$0.80**			
Location:	Monroe, NH & Barnet, VT			
Electric Market Area:	ISO-NE Northern NE			
Nameplate Capacity (MW):	160			
Assumed Capacity for Capacity Payment (MW):	165.408			

Generation		
Generation Type	**Total MWh**	[redacted]
Historic Net Generation:	340,355	
Qualifying Class I REC Generation:	340,355	

Operating Expenses		
Operation & Maintenance ($/000)	$3,012	Input
Administrative & General ($/000)	$3,249	Input
Capital Maintenance ($/000)	0.50%	Input
Miscellaneous #1	$0	Input
Miscellaneous #2	$0	Input
Miscellaneous #3	$0	Input

Financial Assumptions		
Federal Income Tax Rate:	21.00%	Input (default 21%)
State Tax Rate:	7.50%	Input (default 7.7%)
Effective State Tax Rate:	5.93%	(1 minus Fed Tax Rate) x State Tax Rate)
Combined Income Tax Rate:	26.90%	Fed Tax Rate + Effective State Tax Rate (rounded)
After Tax Total Cost of Capital:	5.90%	Input
Effective Property Tax Percentage:	1.79%	Input
Income Tax Effected Property Tax Percentage:	1.31%	(1 minus Combined Income Tax Rate) x Property Tax Percentage
After Income Tax Weighted Average Cost Of Capital:	7.211%	(debt rate x debt %) x (1 minus Inc Tax Rate) + (equity rate x equity %) + Property Tax Rate
After Income Tax Weighted Average Cost Of Capital (rounded):	7.20%	
Terminal Capitalization Rate:	7.20%	Input
Land/Site Valuation $/1000:	$4,881	Input
Inflation Rate:	3.00%	Input



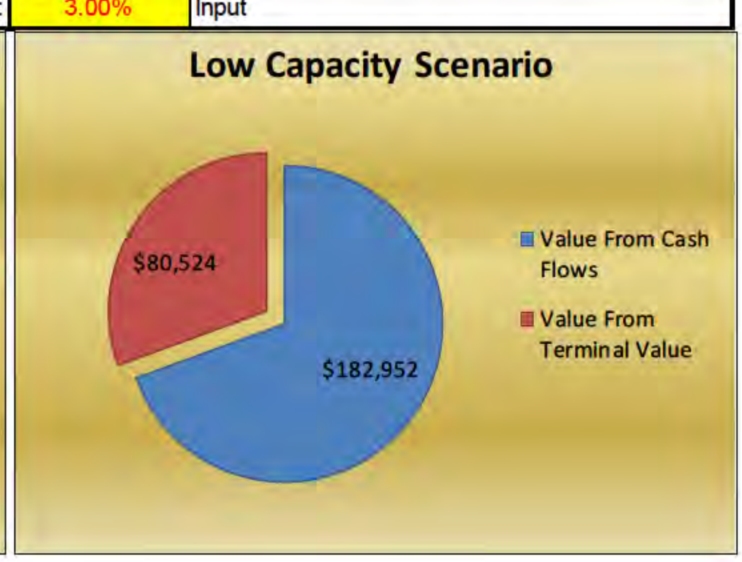


Table 16: Comerford High-Capacity Price Scenario

High Capacity Price Scenario

Row	Plant Name: Comerford		Valuation Date: April 1 2023																			
1	Escalation Rate	3.00%	160	Yellow Highlighted Cells With Red Font are LINKED with Energy, Capacity, & REC																		
2	Blue Cells With Red Font are INPUT Cells For This Worksheet			Tan Highlighted Cells With Red Font are LINKED With DCF Inputs Worksheet																		
3	**DCF Terms**																					
4	Tax Year		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
5	DCF Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6	Escalation Factor		1.000	1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267	1.305	1.344	1.384	1.426	1.469	1.513	1.558	1.605	1.653	1.702	1.754
7	**Plant Capacity and Generation**																					
8	**Capacity (MW) (assumed for capacity payment)**		165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408
9	*Historic On-Peak Generation (MWh)*		[redacted]																			
10	*Historic Off-Peak Generation (MWh)*																					
11	**Total Historic Generation (MWh)**		340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355
12	**Revenue**																					
13	**Wholesale Market Based Energy Revenue**																					
14	*Annual Energy Price On-Peak ($/MWh)*		$58.41	$53.84	$51.39	$49.63	$49.08	$49.58	$50.61	$52.10	$54.06	$56.40	$59.15	$61.57	$63.78	$65.28	$67.09	$69.65	$70.50	$73.45	$75.88	$77.53
15	*Historic Generation - On-Peak ($/MWh)*		[redacted]																			
16	Annual Historic - On-Peak Revenue ($/000)																					
17	*Annual Energy Price Off-Peak ($/MWh)*		$44.83	$41.33	$39.45	$38.10	$37.68	$38.06	$38.85	$39.99	$41.49	$43.29	$45.40	$47.26	$48.96	$50.11	$51.50	$53.46	$54.11	$56.38	$58.25	$59.51
18	*Historic Generation - Off-Peak ($/MWh)*		[redacted]																			
19	Annual Historic - Off-Peak Revenue ($/000)																					
20	**Total Annual Wholesale Market Based Energy Revenue ($/000)**		$17,713	$16,328	$15,585	$15,052	$14,885	$15,036	$15,349	$15,801	$16,394	$17,104	$17,937	$18,672	$19,343	$19,798	$20,348	$21,123	$21,380	$22,277	$23,013	$23,513
21	**Renewable Energy Certificate Revenue**																					
22	*Class I REC Price ($/MWh)*		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
23	*Qualifying Class I REC Generation (MWh)*		340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355
24	Class I REC Revenue ($/000)		$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021
28	**Annual REC Revenue ($/000)**		$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021
29	**Capacity Revenue**																					
30	Capacity (MW) (assumed for capacity payment)		165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408
31	Capacity Rate ($/kW-yr))		$33.01	$27.34	$30.10	$30.79	$31.08	$50.45	$70.94	$92.63	$115.55	$119.02	$122.59	$126.26	$130.05	$133.95	$137.97	$142.11	$146.37	$150.77	$155.29	$159.95
32	**Annual Capacity Revenue ($/000)**		$5,460	$4,523	$4,979	$5,092	$5,141	$8,344	$11,735	$15,321	$19,113	$19,686	$20,277	$20,885	$21,512	$22,157	$22,822	$23,506	$24,212	$24,938	$25,686	$26,457
33	**Misc./Ancillary Revenue**																					
34	**Annual Misc./Ancillary Revenue Escalated by Inflation Rate ($/000)**		$1,766	$1,819	$1,874	$1,930	$1,988	$2,047	$2,109	$2,172	$2,237	$2,304	$2,373	$2,445	$2,518	$2,593	$2,671	$2,751	$2,834	$2,919	$3,006	$3,097
35	**Total All Revenues ($/000)**		$25,960	$23,691	$23,459	$23,095	$23,035	$26,448	$30,214	$34,315	$38,765	$40,115	$41,609	$43,023	$44,394	$45,570	$46,862	$48,402	$49,446	$51,154	$52,727	$54,088
36	**Expenses**																					
37	**Plant Expenses**																					
38	Operation & Maintenance ($/000)	$3,012	$3,012	$3,102	$3,195	$3,291	$3,390	$3,492	$3,596	$3,704	$3,815	$3,930	$4,048	$4,169	$4,294	$4,423	$4,556	$4,692	$4,833	$4,978	$5,127	$5,281
39	Administrative & General ($/000)	$3,249	$3,249	$3,346	$3,447	$3,550	$3,657	$3,766	$3,879	$3,996	$4,115	$4,239	$4,366	$4,497	$4,632	$4,771	$4,914	$5,062	$5,213	$5,370	$5,531	$5,697
40	Capital Maintenance ($/000)	0.50%	$1,711	$1,762	$1,815	$1,870	$1,926	$1,984	$2,043	$2,104	$2,168	$2,233	$2,300	$2,369	$2,440	$2,513	$2,588	$2,666	$2,746	$2,828	$2,913	$3,000
41	Miscellaneous #1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Miscellaneous #2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Miscellaneous #3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	**Total Combined Expenses ($/000)**		$7,972	$8,211	$8,457	$8,711	$8,972	$9,241	$9,519	$9,804	$10,098	$10,401	$10,713	$11,035	$11,366	$11,707	$12,058	$12,420	$12,792	$13,176	$13,571	$13,978
45	**Net Income**																					
46	**Net Operating Cash Flow - EBITDA ($/000)**		$17,988	$15,481	$15,002	$14,385	$14,063	$17,207	$20,695	$24,511	$28,667	$29,714	$30,895	$31,988	$33,028	$33,863	$34,804	$35,982	$36,654	$37,978	$39,156	$40,109
47	**Depreciation and Income Taxes**																					
48	MACRS Depreciation Rate		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
49	Tax Depreciation plus Rollover ($/000)		$12,833	$24,705	$32,074	$38,211	$43,378	$47,401	$46,922	$41,702	$32,460	$19,060	$15,270	$15,266	$15,270	$15,266	$15,270	$15,266	$15,270	$15,266	$15,270	$15,266
50	Rollover Depreciation ($/000)		$0	-$9,224	-$17,072	-$23,827	-$29,315	-$30,194	-$26,227	-$17,190	-$3,793	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	Taxable Income - After All Expenses and Depreciation ($/000)		$5,155	$0	$0	$0	$0	$0	$0	$0	$0	$10,654	$15,625	$16,721	$17,758	$18,596	$19,534	$20,715	$21,384	$22,712	$23,886	$24,843
52	Combined State and Federal Income Tax ($/000)	26.9%	$1,387	$0	$0	$0	$0	$0	$0	$0	$0	$2,866	$4,203	$4,498	$4,777	$5,002	$5,255	$5,572	$5,752	$6,110	$6,425	$6,683
53	**After-Tax Net Cash Flow ($/000)**		$16,601	$15,481	$15,002	$14,385	$14,063	$17,207	$20,695	$24,511	$28,667	$26,848	$26,692	$27,490	$28,251	$28,860	$29,549	$30,409	$30,902	$31,869	$32,730	$33,427
54	**Discount Factor @**	7.20%	0.93284	0.87018	0.81174	0.75722	0.70636	0.65892	0.61466	0.57338	0.53487	0.49894	0.46543	0.43417	0.40501	0.37781	0.35243	0.32876	0.30668	0.28608	0.26687	0.24895
55	**Annual Discounted Cash Flow ($/000)**		$15,486	$13,471	$12,178	$10,892	$9,933	$11,338	$12,721	$14,054	$15,333	$13,396	$12,423	$11,935	$11,442	$10,904	$10,414	$9,997	$9,477	$9,117	$8,735	$8,321
56																						
57	**Sum of the Discounted Cash Flows ($/000)**	$231,568																				
58	Year 20 After-Tax Net Cash Flow ($/000)	$33,427																				
59	Terminal Capitalization Rate	7.2%																				
60	Terminal Value	$464,258																				
61	**Present Value of Terminal Value ($/000)**	$115,575																				
62	**Total DCF Valuation (rounded) ($/000)**	$347,100																				

Table 17: Comerford Low-Capacity Price Scenario

Low Capacity Price Scenario

Row	Plant Name: Comerford		Valuation Date: April 1 2023																			
1	Escalation Rate	3.00%	160	Yellow Highlighted Cells With Red Font are LINKED with Energy, Capacity, & REC																		
2	Blue Cells With Red Font are INPUT Cells For This Worksheet			Tan Highlighted Cells With Red Font are LINKED With DCF Inputs Worksheet																		
3	**DCF Terms**																					
4	Tax Year		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
5	DCF Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6	Escalation Factor		1.000	1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267	1.305	1.344	1.384	1.426	1.469	1.513	1.558	1.605	1.653	1.702	1.754
7	**Plant Capacity and Generation**																					
8	**Capacity (MW) (assumed for capacity payment)**		165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408
9	*Historic On-Peak Generation (MWh)*		[redacted]																			
10	*Historic Off-Peak Generation (MWh)*																					
11	**Total Historic Generation (MWh)**		340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355
12	**Revenue**																					
13	**Wholesale Market Based Energy Revenue**																					
14	*Annual Energy Price On-Peak ($/MWh)*		$58.41	$53.84	$51.39	$49.63	$49.08	$49.58	$50.61	$52.10	$54.06	$56.40	$59.15	$61.57	$63.78	$65.28	$67.09	$69.65	$70.50	$73.45	$75.88	$77.53
15	*Historic Generation - On-Peak ($/MWh)*		[redacted]																			
16	Annual Historic - On-Peak Revenue ($/000)																					
17	*Annual Energy Price Off-Peak ($/MWh)*		$44.83	$41.33	$39.45	$38.10	$37.68	$38.06	$38.85	$39.99	$41.49	$43.29	$45.40	$47.26	$48.96	$50.11	$51.50	$53.46	$54.11	$56.38	$58.25	$59.51
18	*Historic Generation - Off-Peak ($/MWh)*		[redacted]																			
19	Annual Historic - Off-Peak Revenue ($/000)																					
20	**Total Annual Wholesale Market Based Energy Revenue ($/000)**		$17,713	$16,328	$15,585	$15,052	$14,885	$15,036	$15,349	$15,801	$16,394	$17,104	$17,937	$18,672	$19,343	$19,798	$20,348	$21,123	$21,380	$22,277	$23,013	$23,513
21	**Renewable Energy Certificate Revenue**																					
22	*Class I REC Price ($/MWh)*		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
23	*Qualifying Class I REC Generation (MWh)*		340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355
24	Class I REC Revenue ($/000)		$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021
28	**Annual REC Revenue ($/000)**		$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021
29	**Capacity Revenue**																					
30	Capacity (MW) (assumed for capacity payment)		165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408
31	Capacity Rate ($/kW-yr))		$33.01	$27.34	$30.10	$30.79	$31.08	$37.23	$43.72	$50.56	$57.77	$59.51	$61.29	$63.13	$65.03	$66.98	$68.99	$71.06	$73.19	$75.38	$77.64	$79.97
32	**Annual Capacity Revenue ($/000)**		$5,460	$4,523	$4,979	$5,092	$5,141	$6,158	$7,231	$8,363	$9,556	$9,843	$10,138	$10,443	$10,756	$11,078	$11,411	$11,753	$12,106	$12,469	$12,843	$13,228
33	**Misc./Ancillary Revenue**																					
34	**Annual Misc./Ancillary Revenue Escalated by Inflation Rate ($/000)**		$1,766	$1,819	$1,874	$1,930	$1,988	$2,047	$2,109	$2,172	$2,237	$2,304	$2,373	$2,445	$2,518	$2,593	$2,671	$2,751	$2,834	$2,919	$3,006	$3,097
35	**Total All Revenues ($/000)**		$25,960	$23,691	$23,459	$23,095	$23,035	$24,262	$25,710	$27,357	$29,209	$30,272	$31,470	$32,580	$33,638	$34,491	$35,451	$36,648	$37,340	$38,686	$39,884	$40,859
36	**Expenses**																					
37	**Plant Expenses**																					
38	Operation & Maintenance ($/000)	$3,012	$3,012	$3,102	$3,195	$3,291	$3,390	$3,492	$3,596	$3,704	$3,815	$3,930	$4,048	$4,169	$4,294	$4,423	$4,556	$4,692	$4,833	$4,978	$5,127	$5,281
39	Administrative & General ($/000)	$3,249	$3,249	$3,346	$3,447	$3,550	$3,657	$3,766	$3,879	$3,996	$4,115	$4,239	$4,366	$4,497	$4,632	$4,771	$4,914	$5,062	$5,213	$5,370	$5,531	$5,697
40	Capital Maintenance ($/000)	0.50%	$1,293	$1,332	$1,372	$1,413	$1,455	$1,499	$1,544	$1,590	$1,638	$1,687	$1,738	$1,790	$1,844	$1,899	$1,956	$2,015	$2,075	$2,137	$2,201	$2,267
41	Miscellaneous #1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Miscellaneous #2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Miscellaneous #3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	**Total Combined Expenses ($/000)**		$7,554	$7,780	$8,014	$8,254	$8,502	$8,757	$9,020	$9,290	$9,569	$9,856	$10,152	$10,456	$10,770	$11,093	$11,426	$11,768	$12,121	$12,485	$12,860	$13,245
45	**Net Income**																					
46	**Net Operating Cash Flow - EBITDA ($/000)**		$18,406	$15,911	$15,445	$14,841	$14,533	$15,505	$16,690	$18,067	$19,640	$20,416	$21,319	$22,124	$22,868	$23,398	$24,025	$24,880	$25,219	$26,200	$27,024	$27,614
47	**Depreciation and Income Taxes**																					
48	MACRS Depreciation Rate		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
49	Tax Depreciation plus Rollover ($/000)		$9,698	$18,670	$20,027	$20,556	$20,490	$19,625	$16,761	$11,765	$11,540	$11,537	$11,540	$11,537	$11,540	$11,537	$11,540	$11,537	$11,540	$11,537	$11,540	$11,537
50	Rollover Depreciation ($/000)		$0	-$2,759	-$4,581	-$5,715	-$5,957	-$4,119	-$70	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	Taxable Income - After All Expenses and Depreciation ($/000)		$8,708	$0	$0	$0	$0	$0	$0	$6,302	$8,100	$8,879	$9,779	$10,587	$11,329	$11,861	$12,485	$13,343	$13,679	$14,663	$15,485	$16,077
52	Combined State and Federal Income Tax ($/000)	26.9%	$2,342	$0	$0	$0	$0	$0	$0	$1,695	$2,179	$2,388	$2,631	$2,848	$3,047	$3,191	$3,359	$3,589	$3,680	$3,944	$4,165	$4,325
53	**After-Tax Net Cash Flow ($/000)**		$16,064	$15,911	$15,445	$14,841	$14,533	$15,505	$16,690	$16,372	$17,461	$18,028	$18,688	$19,276	$19,821	$20,208	$20,666	$21,291	$21,539	$22,256	$22,859	$23,289
54	**Discount Factor @**	7.20%	0.93284	0.87018	0.81174	0.75722	0.70636	0.65892	0.61466	0.57338	0.53487	0.49894	0.46543	0.43417	0.40501	0.37781	0.35243	0.32876	0.30668	0.28608	0.26687	0.24895
55	**Annual Discounted Cash Flow ($/000)**		$14,985	$13,846	$12,538	$11,238	$10,266	$10,217	$10,259	$9,387	$9,339	$8,995	$8,698	$8,369	$8,028	$7,635	$7,284	$7,000	$6,606	$6,367	$6,100	$5,798
56																						
57	**Sum of the Discounted Cash Flows ($/000)**	$182,952																				
58	Year 20 After-Tax Net Cash Flow ($/000)	$23,289																				
59	Terminal Capitalization Rate	7.2%																				
60	Terminal Value	$323,462																				
61	**Present Value of Terminal Value ($/000)**	$80,524																				
62	**Total DCF Valuation (rounded) ($/000)**	**$263,500**																				

Table 18: Comerford Historic Capacity Price Scenario

Historic Capacity Price Scenario

Row	Plant Name: Comerford		Valuation Date: April 1 2023																			
1	Escalation Rate	3.00%	160	Yellow Highlighted Cells With Red Font are LINKED with Energy, Capacity, & REC																		
2	Blue Cells With Red Font are INPUT Cells For This Worksheet			Tan Highlighted Cells With Red Font are LINKED With DCF Inputs Worksheet																		
3	**DCF Terms**																					
4	Tax Year		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
5	DCF Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6	Escalation Factor		1.000	1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267	1.305	1.344	1.384	1.426	1.469	1.513	1.558	1.605	1.653	1.702	1.754
7	**Plant Capacity and Generation**																					
8	**Capacity (MW) (assumed for capacity payment)**		165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408
9	*Historic On-Peak Generation (MWh)*		[redacted]																			
10	*Historic Off-Peak Generation (MWh)*																					
11	**Total Historic Generation (MWh)**		340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355
12	**Revenue**																					
13	**Wholesale Market Based Energy Revenue**																					
14	*Annual Energy Price On-Peak ($/MWh)*		$58.41	$53.84	$51.39	$49.63	$49.08	$49.58	$50.61	$52.10	$54.06	$56.40	$59.15	$61.57	$63.78	$65.28	$67.09	$69.65	$70.50	$73.45	$75.88	$77.53
15	*Historic Generation - On-Peak ($/MWh)*		[redacted]																			
16	Annual Historic - On-Peak Revenue ($/000)																					
17	*Annual Energy Price Off-Peak ($/MWh)*		$44.83	$41.33	$39.45	$38.10	$37.68	$38.06	$38.85	$39.99	$41.49	$43.29	$45.40	$47.26	$48.96	$50.11	$51.50	$53.46	$54.11	$56.38	$58.25	$59.51
18	*Historic Generation - Off-Peak ($/MWh)*		[redacted]																			
19	Annual Historic - Off-Peak Revenue ($/000)																					
20	**Total Annual Wholesale Market Based Energy Revenue ($/000)**		$17,713	$16,328	$15,585	$15,052	$14,885	$15,036	$15,349	$15,801	$16,394	$17,104	$17,937	$18,672	$19,343	$19,798	$20,348	$21,123	$21,380	$22,277	$23,013	$23,513
21	**Renewable Energy Certificate Revenue**																					
22	*Class I REC Price ($/MWh)*		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
23	*Qualifying Class I REC Generation (MWh)*		340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355	340,355
24	Class I REC Revenue ($/000)		$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021
28	**Annual REC Revenue ($/000)**		$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021	$1,021
29	**Capacity Revenue**																					
30	Capacity (MW) (assumed for capacity payment)		165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408	165.408
31	Capacity Rate ($/kW-yr))		$33.01	$27.34	$30.10	$30.79	$31.08	$38.53	$44.43	$50.64	$63.47	$65.38	$67.34	$69.36	$71.44	$73.58	$75.79	$78.07	$80.41	$82.82	$85.30	$87.86
32	**Annual Capacity Revenue ($/000)**		$5,460	$4,523	$4,979	$5,092	$5,141	$6,373	$7,348	$8,376	$10,499	$10,814	$11,139	$11,473	$11,817	$12,172	$12,537	$12,913	$13,300	$13,699	$14,110	$14,533
33	**Misc./Ancillary Revenue**																					
34	**Annual Misc./Ancillary Revenue Escalated by Inflation Rate ($/000)**		$1,766	$1,819	$1,874	$1,930	$1,988	$2,047	$2,109	$2,172	$2,237	$2,304	$2,373	$2,445	$2,518	$2,593	$2,671	$2,751	$2,834	$2,919	$3,006	$3,097
35	**Total All Revenues ($/000)**		$25,960	$23,691	$23,459	$23,095	$23,035	$24,478	$25,827	$27,370	$30,152	$31,243	$32,470	$33,610	$34,699	$35,584	$36,577	$37,808	$38,535	$39,916	$41,151	$42,165
36	**Expenses**																					
37	**Plant Expenses**																					
38	Operation & Maintenance ($/000)	$3,012	$3,012	$3,102	$3,195	$3,291	$3,390	$3,492	$3,596	$3,704	$3,815	$3,930	$4,048	$4,169	$4,294	$4,423	$4,556	$4,692	$4,833	$4,978	$5,127	$5,281
39	Administrative & General ($/000)	$3,249	$3,249	$3,346	$3,447	$3,550	$3,657	$3,766	$3,879	$3,996	$4,115	$4,239	$4,366	$4,497	$4,632	$4,771	$4,914	$5,062	$5,213	$5,370	$5,531	$5,697
40	Capital Maintenance ($/000)	0.50%	$1,332	$1,372	$1,413	$1,455	$1,499	$1,544	$1,590	$1,638	$1,687	$1,737	$1,790	$1,843	$1,899	$1,955	$2,014	$2,075	$2,137	$2,201	$2,267	$2,335
41	Miscellaneous #1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Miscellaneous #2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Miscellaneous #3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	**Total Combined Expenses ($/000)**		$7,592	$7,820	$8,055	$8,296	$8,545	$8,801	$9,065	$9,337	$9,618	$9,906	$10,203	$10,509	$10,825	$11,149	$11,484	$11,828	$12,183	$12,549	$12,925	$13,313
45	**Net Income**																					
46	**Net Operating Cash Flow - EBITDA ($/000)**		$18,368	$15,871	$15,405	$14,799	$14,490	$15,676	$16,762	$18,033	$20,534	$21,337	$22,267	$23,101	$23,874	$24,435	$25,093	$25,980	$26,351	$27,367	$28,226	$28,852
47	**Depreciation and Income Taxes**																					
48	MACRS Depreciation Rate		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
49	Tax Depreciation plus Rollover ($/000)		$9,987	$19,226	$21,136	$22,182	$22,598	$22,183	$19,524	$14,805	$11,883	$11,880	$11,883	$11,880	$11,883	$11,880	$11,883	$11,880	$11,883	$11,880	$11,883	$11,880
50	Rollover Depreciation ($/000)		$0	-$3,354	-$5,732	-$7,383	-$8,108	-$6,507	-$2,762	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	Taxable Income - After All Expenses and Depreciation ($/000)		$8,381	$0	$0	$0	$0	$0	$0	$3,227	$8,651	$9,456	$10,384	$11,220	$11,991	$12,554	$13,209	$14,099	$14,468	$15,487	$16,343	$16,971
52	Combined State and Federal Income Tax ($/000)	26.9%	$2,254	$0	$0	$0	$0	$0	$0	$868	$2,327	$2,544	$2,793	$3,018	$3,226	$3,377	$3,553	$3,793	$3,892	$4,166	$4,396	$4,565
53	**After-Tax Net Cash Flow ($/000)**		$16,113	$15,871	$15,405	$14,799	$14,490	$15,676	$16,762	$17,164	$18,207	$18,793	$19,474	$20,083	$20,649	$21,058	$21,539	$22,187	$22,460	$23,201	$23,830	$24,286
54	**Discount Factor @**	7.20%	0.93284	0.87018	0.81174	0.75722	0.70636	0.65892	0.61466	0.57338	0.53487	0.49894	0.46543	0.43417	0.40501	0.37781	0.35243	0.32876	0.30668	0.28608	0.26687	0.24895
55	**Annual Discounted Cash Flow ($/000)**		$15,031	$13,811	$12,505	$11,206	$10,235	$10,329	$10,303	$9,842	$9,738	$9,377	$9,064	$8,719	$8,363	$7,956	$7,591	$7,294	$6,888	$6,637	$6,359	$6,046
56																						
57	**Sum of the Discounted Cash Flows ($/000)**		$187,295																			
58	Year 20 After-Tax Net Cash Flow ($/000)		$24,286																			
59	Terminal Capitalization Rate		7.2%																			
60	Terminal Value		$337,311																			
61	**Present Value of Terminal Value ($/000)**		$83,972																			
62	**Total DCF Valuation (rounded) ($/000)**		**$271,300**																			

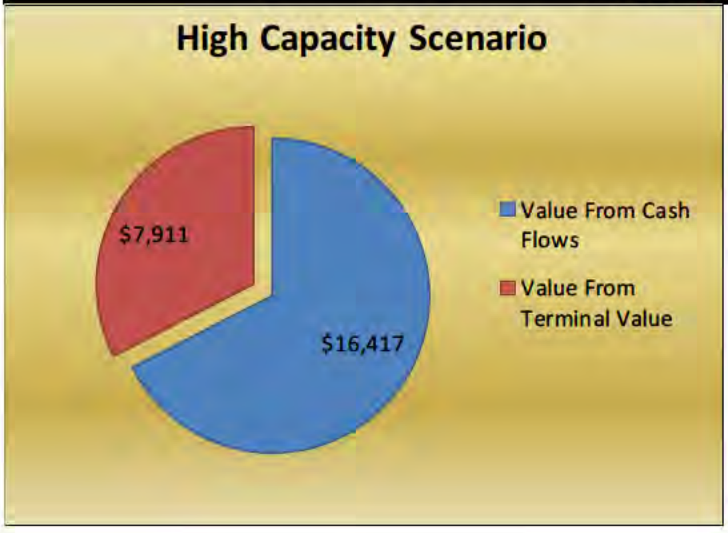
Table 19: McIndoe Station DCF Inputs

Yellow Highlighted Cells With Red Font are INPUT cells			
Plant Name:	McIndoe Falls		
Valuation Date:	April	1	2023
High Capacity Price Scenario			
Estimated Plant Value:	$24,300,000		
Estimated Plant Value ($/kWh-yr):	$0.56		
Low Capacity Price Scenario			
Estimated Plant Value:	$19,600,000		
Estimated Plant Value ($/kWh-yr):	$0.45		
Historic Capacity Price Scenario			
Estimated Plant Value:	$20,000,000		
Estimated Plant Value ($/kWh-yr):	$0.46		
Location:	Monroe, NH & Barnet, VT		
Electric Market Area:	ISO-NE Northern NE		
Nameplate Capacity (MW):	10.56		
Assumed Capacity for Capacity Payment (MW):	10.124		

Generation		
Generation Type	**Total MWh**	[redacted]
Historic Net Generation:	43,617	
Qualifying Class I REC Generation:	43,617	

Operating Expenses		
Operation & Maintenance ($/000)	$634	Input
Administrative & General ($/000)	$317	Input
Capital Maintenance ($/000)	1.00%	Input
Miscellaneous #1	$0	Input
Miscellaneous #2	$0	Input
Miscellaneous #3	$0	Input

Financial Assumptions		
Federal Income Tax Rate:	21.00%	Input (default 21%)
State Tax Rate:	7.50%	Input (default 7.7%)
Effective State Tax Rate:	5.93%	(1 minus Fed Tax Rate) x State Tax Rate)
Combined Income Tax Rate:	26.90%	Fed Tax Rate + Effective State Tax Rate (rounded)
After Tax Total Cost of Capital:	5.90%	Input
Effective Property Tax Percentage:	1.78%	Input
Income Tax Effected Property Tax Percentage:	1.30%	(1 minus Combined Income Tax Rate) x Property Tax Percentage
After Income Tax Weighted Average Cost Of Capital:	7.198%	(debt rate x debt %) x (1 minus Inc Tax Rate) + (equity rate x equity %) + Property Tax Rate
After Income Tax Weighted Average Cost Of Capital (rounded):	7.20%	
Terminal Capitalization Rate:	7.20%	Input
Land/Site Valuation $/1000:	$63	Input
Inflation Rate:	3.00%	Input



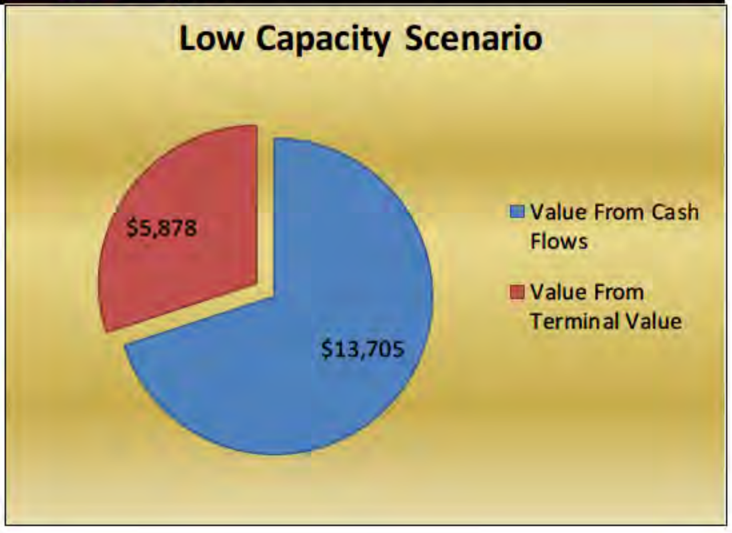


Table 20: McIndoe High-Capacity Price Scenario

Plant Name: McIndoe Falls **Valuation Date:** April 1 2023

High Capacity Price Scenario

Row	Item	Input	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1	Escalation Rate	3.00%	10.56	Yellow Highlighted Cells With Red Font are LINKED with Energy, Capacity, & REC																		
2	Blue Cells With Red Font are INPUT Cells For This Worksheet			Tan Highlighted Cells With Red Font are LINKED With DCF Inputs Worksheet																		
3	**DCF Terms**																					
4	Tax Year		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
5	DCF Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6	Escalation Factor		1.000	1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267	1.305	1.344	1.384	1.426	1.469	1.513	1.558	1.605	1.653	1.702	1.754
7	**Plant Capacity and Generation**																					
8	**Capacity (MW) (assumed for capacity payment)**		10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124
9	*Historic On-Peak Generation (MWh)*		[redacted]																			
10	*Historic Off-Peak Generation (MWh)*																					
11	**Total Historic Generation (MWh)**		43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617
12	**Revenue**																					
13	**Wholesale Market Based Energy Revenue**																					
14	*Annual Energy Price On-Peak ($/MWh)*		$58.41	$53.84	$51.39	$49.63	$49.08	$49.58	$50.61	$52.10	$54.06	$56.40	$59.15	$61.57	$63.78	$65.28	$67.09	$69.65	$70.50	$73.45	$75.88	$77.53
15	*Historic Generation - On-Peak ($/MWh)*		[redacted]																			
16	Annual Historic - On-Peak Revenue ($/000)																					
17	*Annual Energy Price Off-Peak ($/MWh)*		$44.83	$41.33	$39.45	$38.10	$37.68	$38.06	$38.85	$39.99	$41.49	$43.29	$45.40	$47.26	$48.96	$50.11	$51.50	$53.46	$54.11	$56.38	$58.25	$59.51
18	*Historic Generation - Off-Peak ($/MWh)*		[redacted]																			
19	Annual Historic - Off-Peak Revenue ($/000)																					
20	**Total Annual Wholesale Market Based Energy Revenue ($/000)**		$2,253	$2,077	$1,982	$1,915	$1,893	$1,912	$1,952	$2,010	$2,085	$2,175	$2,281	$2,375	$2,460	$2,518	$2,588	$2,687	$2,719	$2,833	$2,927	$2,991
21	**Renewable Energy Certificate Revenue**																					
22	*Class I REC Price ($/MWh)*		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
23	*Qualifying Class I REC Generation (MWh)*		43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617
24	Class I REC Revenue ($/000)		$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44
28	**Annual REC Revenue ($/000)**		$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44
29	**Capacity Revenue**																					
30	Capacity (MW) (assumed for capacity payment)		10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124
31	Capacity Rate ($/kW-yr))		$33.01	$27.34	$30.10	$30.79	$31.08	$50.45	$70.94	$92.63	$115.55	$119.02	$122.59	$126.26	$130.05	$133.95	$137.97	$142.11	$146.37	$150.77	$155.29	$159.95
32	**Annual Capacity Revenue ($/000)**		$334	$277	$305	$312	$315	$511	$718	$938	$1,170	$1,205	$1,241	$1,278	$1,317	$1,356	$1,397	$1,439	$1,482	$1,526	$1,572	$1,619
33	**Misc./Ancillary Revenue**																					
34	**Annual Misc./Ancillary Revenue Escalated by Inflation Rate ($/000)**		$97	$100	$103	$106	$109	$112	$116	$119	$123	$127	$130	$134	$138	$142	$147	$151	$156	$160	$165	$170
35	**Total All Revenues ($/000)**		**$2,728**	**$2,497**	**$2,434**	**$2,376**	**$2,361**	**$2,579**	**$2,830**	**$3,110**	**$3,421**	**$3,551**	**$3,697**	**$3,831**	**$3,959**	**$4,060**	**$4,175**	**$4,320**	**$4,400**	**$4,564**	**$4,708**	**$4,824**
36	**Expenses**																					
37	**Plant Expenses**																					
38	Operation & Maintenance ($/000)	$634	$634	$653	$672	$692	$713	$735	$757	$779	$803	$827	$852	$877	$903	$930	$958	$987	$1,017	$1,047	$1,079	$1,111
39	Administrative & General ($/000)	$317	$317	$326	$336	$346	$357	$367	$378	$390	$401	$413	$426	$439	$452	$465	$479	$494	$508	$524	$539	$556
40	Capital Maintenance ($/000)	1.00%	$242	$250	$257	$265	$273	$281	$289	$298	$307	$316	$326	$335	$346	$356	$367	$378	$389	$401	$413	$425
41	Miscellaneous #1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Miscellaneous #2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Miscellaneous #3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	**Total Combined Expenses ($/000)**		**$1,193**	**$1,229**	**$1,265**	**$1,303**	**$1,342**	**$1,383**	**$1,424**	**$1,467**	**$1,511**	**$1,556**	**$1,603**	**$1,651**	**$1,701**	**$1,752**	**$1,804**	**$1,858**	**$1,914**	**$1,971**	**$2,031**	**$2,092**
45	**Net Income**																					
46	**Net Operating Cash Flow - EBITDA ($/000)**		**$1,535**	**$1,269**	**$1,168**	**$1,072**	**$1,018**	**$1,196**	**$1,406**	**$1,643**	**$1,911**	**$1,994**	**$2,094**	**$2,180**	**$2,258**	**$2,309**	**$2,371**	**$2,462**	**$2,486**	**$2,592**	**$2,677**	**$2,732**
47	**Depreciation and Income Taxes**																					
48	MACRS Depreciation Rate		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
49	Tax Depreciation plus Rollover ($/000)		$909	$1,750	$2,099	$2,428	$2,740	$3,003	$2,991	$2,682	$2,120	$1,290	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081
50	Rollover Depreciation ($/000)		$0	-$481	-$931	-$1,356	-$1,722	-$1,807	-$1,586	-$1,038	-$209	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	Taxable Income - After All Expenses and Depreciation ($/000)		$626	$0	$0	$0	$0	$0	$0	$0	$0	$704	$1,012	$1,099	$1,177	$1,228	$1,290	$1,381	$1,405	$1,511	$1,596	$1,651
52	Combined State and Federal Income Tax ($/000)	26.9%	$168	$0	$0	$0	$0	$0	$0	$0	$0	$189	$272	$296	$317	$330	$347	$371	$378	$406	$429	$444
53	**After-Tax Net Cash Flow ($/000)**		**$1,367**	**$1,269**	**$1,168**	**$1,072**	**$1,018**	**$1,196**	**$1,406**	**$1,643**	**$1,911**	**$1,805**	**$1,821**	**$1,884**	**$1,942**	**$1,979**	**$2,024**	**$2,090**	**$2,108**	**$2,186**	**$2,248**	**$2,288**
54	**Discount Factor @**	7.20%	0.93284	0.87018	0.81174	0.75722	0.70636	0.65892	0.61466	0.57338	0.53487	0.49894	0.46543	0.43417	0.40501	0.37781	0.35243	0.32876	0.30668	0.28608	0.26687	0.24895
55	**Annual Discounted Cash Flow ($/000)**		**$1,275**	**$1,104**	**$948**	**$812**	**$719**	**$788**	**$864**	**$942**	**$1,022**	**$901**	**$848**	**$818**	**$786**	**$748**	**$713**	**$687**	**$647**	**$625**	**$600**	**$570**
56																						
57	**Sum of the Discounted Cash Flows ($/000)**	$16,417																				
58	Year 20 After-Tax Net Cash Flow ($/000)	$2,288																				
59	Terminal Capitalization Rate	7.2%																				
60	Terminal Value	$31,779																				
61	**Present Value of Terminal Value ($/000)**	$7,911																				
62	**Total DCF Valuation (rounded) ($/000)**	**$24,300**																				

Table 21: McIndoe Low-Capacity Price Scenario

Low Capacity Price Scenario

Row	Plant Name: McIndoe Falls		Valuation Date: April 1 2023																			
1	Escalation Rate	3.00%	10.56	Yellow Highlighted Cells With Red Font are LINKED with Energy, Capacity, & REC																		
2	Blue Cells With Red Font are INPUT Cells For This Worksheet			Tan Highlighted Cells With Red Font are LINKED With DCF Inputs Worksheet																		
3	**DCF Terms**																					
4	Tax Year		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
5	DCF Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6	Escalation Factor		1.000	1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267	1.305	1.344	1.384	1.426	1.469	1.513	1.558	1.605	1.653	1.702	1.754
7	**Plant Capacity and Generation**																					
8	**Capacity (MW) (assumed for capacity payment)**		**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**	**10.124**
9	*Historic On-Peak Generation (MWh)*		[redacted]																			
10	*Historic Off-Peak Generation (MWh)*																					
11	**Total Historic Generation (MWh)**		**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**	**43,617**
12	**Revenue**																					
13	**Wholesale Market Based Energy Revenue**																					
14	*Annual Energy Price On-Peak ($/MWh)*		*$58.41*	*$53.84*	*$51.39*	*$49.63*	*$49.08*	*$49.58*	*$50.61*	*$52.10*	*$54.06*	*$56.40*	*$59.15*	*$61.57*	*$63.78*	*$65.28*	*$67.09*	*$69.65*	*$70.50*	*$73.45*	*$75.88*	*$77.53*
15	*Historic Generation - On-Peak ($/MWh)*		[redacted]																			
16	Annual Historic - On-Peak Revenue ($/000)																					
17	*Annual Energy Price Off-Peak ($/MWh)*		*$44.83*	*$41.33*	*$39.45*	*$38.10*	*$37.68*	*$38.06*	*$38.85*	*$39.99*	*$41.49*	*$43.29*	*$45.40*	*$47.26*	*$48.96*	*$50.11*	*$51.50*	*$53.46*	*$54.11*	*$56.38*	*$58.25*	*$59.51*
18	*Historic Generation - Off-Peak ($/MWh)*		[redacted]																			
19	Annual Historic - Off-Peak Revenue ($/000)																					
20	**Total Annual Wholesale Market Based Energy Revenue ($/000)**		**$2,253**	**$2,077**	**$1,982**	**$1,915**	**$1,893**	**$1,912**	**$1,952**	**$2,010**	**$2,085**	**$2,175**	**$2,281**	**$2,375**	**$2,460**	**$2,518**	**$2,588**	**$2,687**	**$2,719**	**$2,833**	**$2,927**	**$2,991**
21	**Renewable Energy Certificate Revenue**																					
22	*Class I REC Price ($/MWh)*		*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*	*$1*
23	*Qualifying Class I REC Generation (MWh)*		*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*	*43,617*
24	Class I REC Revenue ($/000)		$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44
28	**Annual REC Revenue ($/000)**		**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**	**$44**
29	**Capacity Revenue**																					
30	Capacity (MW) (assumed for capacity payment)		*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*	*10.124*
31	Capacity Rate ($/kW-yr))		*$33.01*	*$27.34*	*$30.10*	*$30.79*	*$31.08*	*$37.23*	*$43.72*	*$50.56*	*$57.77*	*$59.51*	*$61.29*	*$63.13*	*$65.03*	*$66.98*	*$68.99*	*$71.06*	*$73.19*	*$75.38*	*$77.64*	*$79.97*
32	**Annual Capacity Revenue ($/000)**		**$334**	**$277**	**$305**	**$312**	**$315**	**$377**	**$443**	**$512**	**$585**	**$602**	**$621**	**$639**	**$658**	**$678**	**$698**	**$719**	**$741**	**$763**	**$786**	**$810**
33	**Misc./Ancillary Revenue**																					
34	**Annual Misc./Ancillary Revenue Escalated by Inflation Rate ($/000)**		**$97**	**$100**	**$103**	**$106**	**$109**	**$112**	**$116**	**$119**	**$123**	**$127**	**$130**	**$134**	**$138**	**$142**	**$147**	**$151**	**$156**	**$160**	**$165**	**$170**
35	**Total All Revenues ($/000)**		**$2,728**	**$2,497**	**$2,434**	**$2,376**	**$2,361**	**$2,445**	**$2,554**	**$2,685**	**$2,837**	**$2,948**	**$3,076**	**$3,192**	**$3,301**	**$3,382**	**$3,477**	**$3,601**	**$3,660**	**$3,801**	**$3,922**	**$4,014**
36	**Expenses**																					
37	**Plant Expenses**																					
38	Operation & Maintenance ($/000)	$634	$634	$653	$672	$692	$713	$735	$757	$779	$803	$827	$852	$877	$903	$930	$958	$987	$1,017	$1,047	$1,079	$1,111
39	Administrative & General ($/000)	$317	$317	$326	$336	$346	$357	$367	$378	$390	$401	$413	$426	$439	$452	$465	$479	$494	$508	$524	$539	$556
40	Capital Maintenance ($/000)	1.00%	$195	$201	$207	$213	$220	$226	$233	$240	$247	$255	$263	$270	$279	$287	$296	$304	$314	$323	$333	$343
41	Miscellaneous #1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Miscellaneous #2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Miscellaneous #3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	**Total Combined Expenses ($/000)**		**$1,146**	**$1,180**	**$1,216**	**$1,252**	**$1,290**	**$1,328**	**$1,368**	**$1,409**	**$1,451**	**$1,495**	**$1,540**	**$1,586**	**$1,634**	**$1,683**	**$1,733**	**$1,785**	**$1,839**	**$1,894**	**$1,951**	**$2,009**
45	**Net Income**																					
46	**Net Operating Cash Flow - EBITDA ($/000)**		**$1,582**	**$1,317**	**$1,218**	**$1,124**	**$1,071**	**$1,117**	**$1,186**	**$1,275**	**$1,385**	**$1,453**	**$1,536**	**$1,606**	**$1,667**	**$1,700**	**$1,744**	**$1,816**	**$1,821**	**$1,907**	**$1,971**	**$2,005**
47	**Depreciation and Income Taxes**																					
48	MACRS Depreciation Rate		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
49	Tax Depreciation plus Rollover ($/000)		$733	$1,410	$1,398	$1,387	$1,379	$1,340	$1,178	$883	$872	$872	$872	$872	$872	$872	$872	$872	$872	$872	$872	$872
50	Rollover Depreciation ($/000)		$0	-$93	-$180	-$263	-$308	-$223	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	Taxable Income - After All Expenses and Depreciation ($/000)		$849	$0	$0	$0	$0	$0	$8	$392	$513	$582	$664	$734	$795	$828	$872	$944	$949	$1,035	$1,100	$1,133
52	Combined State and Federal Income Tax ($/000)	26.9%	$228	$0	$0	$0	$0	$0	$2	$105	$138	$156	$179	$198	$214	$223	$235	$254	$255	$278	$296	$305
53	**After-Tax Net Cash Flow ($/000)**		**$1,353**	**$1,317**	**$1,218**	**$1,124**	**$1,071**	**$1,117**	**$1,184**	**$1,170**	**$1,247**	**$1,297**	**$1,357**	**$1,408**	**$1,453**	**$1,477**	**$1,509**	**$1,562**	**$1,566**	**$1,628**	**$1,676**	**$1,700**
54	**Discount Factor @**	7.20%	0.93284	0.87018	0.81174	0.75722	0.70636	0.65892	0.61466	0.57338	0.53487	0.49894	0.46543	0.43417	0.40501	0.37781	0.35243	0.32876	0.30668	0.28608	0.26687	0.24895
55	**Annual Discounted Cash Flow ($/000)**		**$1,263**	**$1,146**	**$989**	**$851**	**$757**	**$736**	**$728**	**$671**	**$667**	**$647**	**$632**	**$611**	**$588**	**$558**	**$532**	**$513**	**$480**	**$466**	**$447**	**$423**
56																						
57	**Sum of the Discounted Cash Flows ($/000)**	**$13,705**																				
58	Year 20 After-Tax Net Cash Flow ($/000)	$1,700																				
59	Terminal Capitalization Rate	7.2%																				
60	Terminal Value	$23,612																				
61	**Present Value of Terminal Value ($/000)**	**$5,878**																				
62	**Total DCF Valuation (rounded) ($/000)**	**$19,600**																				

Table 22: McIndoe Historic-Capacity Price Scenario

Row	Plant Name: McIndoe Falls			Valuation Date: April 1 2023
1	Escalation Rate	3.00%	10.56	Yellow Highlighted Cells With Red Font are LINKED with Energy, Capacity, & REC
2	Blue Cells With Red Font are INPUT Cells For This Worksheet			Tan Highlighted Cells With Red Font are LINKED With DCF Inputs Worksheet

Historic Capacity Price Scenario

Row	Item	Input	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
3	**DCF Terms**																					
4	Tax Year		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
5	DCF Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6	Escalation Factor		1.000	1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267	1.305	1.344	1.384	1.426	1.469	1.513	1.558	1.605	1.653	1.702	1.754
7	**Plant Capacity and Generation**																					
8	**Capacity (MW) (assumed for capacity payment)**		10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124
9	*Historic On-Peak Generation (MWh)*		[redacted]																			
10	*Historic Off-Peak Generation (MWh)*																					
11	**Total Historic Generation (MWh)**		43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617
12	**Revenue**																					
13	**Wholesale Market Based Energy Revenue**																					
14	*Annual Energy Price On-Peak ($/MWh)*		$58.41	$53.84	$51.39	$49.63	$49.08	$49.58	$50.61	$52.10	$54.06	$56.40	$59.15	$61.57	$63.78	$65.28	$67.09	$69.65	$70.50	$73.45	$75.88	$77.53
15	*Historic Generation - On-Peak ($/MWh)*		[redacted]																			
16	Annual Historic - On-Peak Revenue ($/000)																					
17	*Annual Energy Price Off-Peak ($/MWh)*		$44.83	$41.33	$39.45	$38.10	$37.68	$38.06	$38.85	$39.99	$41.49	$43.29	$45.40	$47.26	$48.96	$50.11	$51.50	$53.46	$54.11	$56.38	$58.25	$59.51
18	*Historic Generation - Off-Peak ($/MWh)*		[redacted]																			
19	Annual Historic - Off-Peak Revenue ($/000)																					
20	**Total Annual Wholesale Market Based Energy Revenue ($/000)**		$2,253	$2,077	$1,982	$1,915	$1,893	$1,912	$1,952	$2,010	$2,085	$2,175	$2,281	$2,375	$2,460	$2,518	$2,588	$2,687	$2,719	$2,833	$2,927	$2,991
21	**Renewable Energy Certificate Revenue**																					
22	*Class I REC Price ($/MWh)*		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
23	*Qualifying Class I REC Generation (MWh)*		43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617	43,617
24	Class I REC Revenue ($/000)		$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44
28	**Annual REC Revenue ($/000)**		$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44	$44
29	**Capacity Revenue**																					
30	Capacity (MW) (assumed for capacity payment)		10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124	10.124
31	Capacity Rate ($/kW-yr))		$33.01	$27.34	$30.10	$30.79	$31.08	$38.53	$44.43	$50.64	$63.47	$65.38	$67.34	$69.36	$71.44	$73.58	$75.79	$78.07	$80.41	$82.82	$85.30	$87.86
32	**Annual Capacity Revenue ($/000)**		$334	$277	$305	$312	$315	$390	$450	$513	$643	$662	$682	$702	$723	$745	$767	$790	$814	$838	$864	$890
33	**Misc./Ancillary Revenue**																					
34	**Annual Misc./Ancillary Revenue Escalated by Inflation Rate ($/000)**		$97	$100	$103	$106	$109	$112	$116	$119	$123	$127	$130	$134	$138	$142	$147	$151	$156	$160	$165	$170
35	**Total All Revenues ($/000)**		$2,728	$2,497	$2,434	$2,376	$2,361	$2,459	$2,561	$2,685	$2,894	$3,007	$3,137	$3,255	$3,365	$3,449	$3,546	$3,672	$3,733	$3,876	$3,999	$4,094
36	**Expenses**																					
37	**Plant Expenses**																					
38	Operation & Maintenance ($/000)	$634	$634	$653	$672	$692	$713	$735	$757	$779	$803	$827	$852	$877	$903	$930	$958	$987	$1,017	$1,047	$1,079	$1,111
39	Administrative & General ($/000)	$317	$317	$326	$336	$346	$357	$367	$378	$390	$401	$413	$426	$439	$452	$465	$479	$494	$508	$524	$539	$556
40	Capital Maintenance ($/000)	1.00%	$199	$205	$212	$218	$224	$231	$238	$245	$253	$260	$268	$276	$284	$293	$302	$311	$320	$330	$339	$350
41	Miscellaneous #1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Miscellaneous #2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Miscellaneous #3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	**Total Combined Expenses ($/000)**		$1,150	$1,184	$1,220	$1,256	$1,294	$1,333	$1,373	$1,414	$1,456	$1,500	$1,545	$1,592	$1,639	$1,688	$1,739	$1,791	$1,845	$1,900	$1,957	$2,016
45	**Net Income**																					
46	**Net Operating Cash Flow - EBITDA ($/000)**		$1,578	$1,313	$1,214	$1,119	$1,067	$1,126	$1,189	$1,271	$1,438	$1,507	$1,592	$1,663	$1,726	$1,761	$1,807	$1,880	$1,888	$1,975	$2,042	$2,078
47	**Depreciation and Income Taxes**																					
48	MACRS Depreciation Rate		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
49	Tax Depreciation plus Rollover ($/000)		$748	$1,439	$1,458	$1,475	$1,495	$1,482	$1,331	$1,044	$890	$889	$890	$889	$890	$889	$890	$889	$890	$889	$890	$889
50	Rollover Depreciation ($/000)		$0	-$126	-$244	-$356	-$428	-$356	-$142	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	Taxable Income - After All Expenses and Depreciation ($/000)		$830	$0	$0	$0	$0	$0	$0	$228	$548	$618	$702	$774	$837	$871	$917	$991	$998	$1,086	$1,152	$1,188
52	Combined State and Federal Income Tax ($/000)	26.9%	$223	$0	$0	$0	$0	$0	$0	$61	$147	$166	$189	$208	$225	$234	$247	$267	$268	$292	$310	$320
53	**After-Tax Net Cash Flow ($/000)**		$1,355	$1,313	$1,214	$1,119	$1,067	$1,126	$1,189	$1,210	$1,290	$1,341	$1,403	$1,455	$1,501	$1,526	$1,560	$1,614	$1,619	$1,683	$1,732	$1,758
54	**Discount Factor @**	7.20%	0.93284	0.87018	0.81174	0.75722	0.70636	0.65892	0.61466	0.57338	0.53487	0.49894	0.46543	0.43417	0.40501	0.37781	0.35243	0.32876	0.30668	0.28608	0.26687	0.24895
55	**Annual Discounted Cash Flow ($/000)**		$1,264	$1,142	$985	$848	$753	$742	$731	$694	$690	$669	$653	$632	$608	$577	$550	$531	$497	$482	$462	$438
56																						
57	**Sum of the Discounted Cash Flows ($/000)**	$13,946																				
58	Year 20 After-Tax Net Cash Flow ($/000)	$1,758																				
59	Terminal Capitalization Rate	7.2%																				
60	Terminal Value	$24,418																				
61	**Present Value of Terminal Value ($/000)**	$6,079																				
62	**Total DCF Valuation (rounded) ($/000)**	**$20,000**																				

RECONCILIATION

Summary of Concluded Value Estimates and Reconciled Value

Reconciliation is the process of coordinating and integrating the facts to develop a unified conclusion of market value for the Developments. The reconciliation process for this report requires the consideration of the cost approach to value, the sales approach to value, and the income approach to value for the Developments.

We estimated the cost new of the Developments using the reproduction cost new method. The cost approach for hydroelectric facilities of this age and magnitude can be an insightful indicator of value in the absence of sales and income data. However, the Developments are 100 years old and were built in a different era, when energy prices were much higher on a relative basis than they are today. Because of the high cost of construction relative to expected returns on those costs, the Developments would likely not be constructed today. We consider the cost approach probative to the value to both a regulated buyer and a merchant independent power producer, but do not give it any weight in the reconciliation.

We investigated those sales that were considered probative and/or comparable to the Developments and have considered the sales comparison approach. We believe these sales to be reliable indicators of value relative to the Developments, and therefore weighed the sales comparison approach equally with the income capitalization approach for McIndoe, and 1/3 weight for Comerford, as explained below.

Of the approaches to value used in this report, the income capitalization best accounts for the impact of the expected revenues and timing for those revenues, and various expenses and capital maintenance costs to the Developments. Of significant note is the recent qualification of Class I RECs in the State of Connecticut, New Hampshire, and Massachusetts, which is unusual for projects of this size, and provides a significant level of revenue above and beyond the typical comparable plant. Secondly, Comerford is a large peaking unit, with abilities to capitalize on energy costs at a much greater rate than typical hydros. As can be seen in the sale of the Developments, these factors can warrant a significant premium over typical run-of-river facilities. This premium is best captured in the income approach analysis for Comerford. We therefore weighed the income capitalization approach equally with the sales comparison approach for McIndoe, and two-thirds for Comerford.

Therefore, it is our opinion that the market value of the Developments as of April 1, 2023, are reconciled to a value of:

Table 23: Summary of Valuation Methods and Reconciled Value

	A		B	C
Row	**Description | Approach**		**Reconciled Market Value**	**Property**
1			***Property:***	*Comerford*
2	**Valuation Summary**			
3	*0%*	*Cost Approach*	*$515,951,700*	
4	*33%*	*Sales Approach*	*$204,200,000*	
5	*67%*	*Income Approach*	*$294,000,000*	
6			***Reconciled Market Value:***	***$264,000,000***
7			***Property:***	*McIndoe*
8	**Valuation Summary**			
9	*0%*	*Cost Approach*	*$42,321,100*	
10	*50%*	*Sales Approach*	*$26,150,000*	
11	*50%*	*Income Approach*	*$21,300,000*	
12			***Reconciled Market Value:***	***$23,700,000***

Reconciled Value and Allocation of Property

The Developments are situated in two towns, Monroe, NH and Barnet, VT. Based on our previous separation study, we determined that 82.5% of the improvements for Comerford Station and 88.6% of the improvements for McIndoe Station lie within Monroe. Therefore, the concluded value for the Developments in Monroe as of April 1, 2023, is summarized below in Table 24.

Table 24: Reconciled Value and Allocation of Property

	A	B	C
Row	**Description**	**Comerford**	**McIndoe**
1	**Valuation Summary**		
2	Reconciled Market Value:	$264,000,000	$23,700,000
3	*less: Total Land Monroe, NH*	*$1,151,700*	*$421,100*
4	*less: Total Land Barnet, VT*	*$4,347,400*	*$1,225,400*
5	***Subtotal Property Improvements:***	***$258,500,900***	***$22,053,500***
6	***Allocation to Barnet, VT***		
7	Percent Allocation	*17.5%*	*11.4%*
8	***Total Taxable Improvements:***	***$45,237,658***	***$2,514,099***
9	***Allocation to Monroe, NH***		
10	Percent Allocation	*82.5%*	*88.6%*
11	***Total Taxable Improvements:***	***$213,263,243***	***$19,539,401***
12	*Plus: Land - Monroe, NH*	*$1,151,700*	*$421,100*
13	***Total Taxable Value - Monroe, NH (rounded):***	***$214,414,900***	***$19,960,500***

APPRAISER'S CERTIFICATION

I certify that, to the best of my knowledge and belief,

- The statements of fact contained in this report are true and correct.
- My reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions and are my personal, impartial, and unbiased professional analyses, opinions, and conclusions.
- I have no present or prospective interest in the property that is the subject of this report and no personal (or the specified) interest with respect to the parties involved.
- I have performed appraisals and consulting services on an annual basis for annual assessment purposes and have provided litigation support, when necessary, regarding the property that is the subject of this report within the three-year period immediately preceding acceptance to perform this assignment.
- I have no bias with respect to the properties that are the subject of this report or to the parties involved with this assignment.
- My engagement in this assignment was not contingent upon developing or reporting predetermined results.
- My compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.
- My analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the *Uniform Standards of Professional Appraisal Practice (USPAP).*
- A visual inspection of the property that is the subject of this report was made on June 4, 2021, and September 23, 2022 by George E. Sansoucy, P.E.(NH).
- Matthew Sansoucy, P.E.(SC), Certified General Appraiser, has provided technical support, support in developing the three methods of value, and report preparation for this assignment.
- As of the date of this report, I, George E. Sansoucy, have completed the continuing education program for Practicing Affiliates of the Appraisal Institute.
- My opinion of the total market value of the property identified in the report, as of April 1, 2023, is as shown in the reconciliation section of this report.

George E. Sansoucy

George E. Sansoucy, P.E.(NH)
NHCG – 774
NH DRA Certified Property Assessor Supervisor

SANSOUCY
ASSOCIATES