Report of the HydroPower Acquisition Working Group

October 25, 2016

Contents

SUMMARY

Pursuant to Act 130 the Vermont Hydroelectric Power Acquisition Working Group was tasked with studying the potential acquisition of the hydroelectric facilities owned by TransCanada and located on the Connecticut and Deerfield Rivers. This report fulfils these requirements.

There are three questions inherent in the question of whether the State of Vermont should acquire an ownership interest in the hydroelectric assets.

1. Would an ownership interest provide a benefit to the State?
2. If an ownership interest provides a benefit, what form should it take?
3. Is it feasible to acquire an ownership interest?

Due to the short time-line for submitting a bid, the expected cost of the assets, and the significant costs associated with preparing a legitimate bid, it was not feasible for the State to pursue a bid on its own. The State explored the potential of entering into a partnership with potential bidders, however, many of the bidders have sufficient assets that a partnership is not necessary, and the timing associated with legislative and regulatory approval created a disincentive for such a bidder to submit a joint bid with the State.

This does not mean that there is no further mechanism for the State to obtain some beneficial interest in the dams. As discussed in detail below, the State or the Vermont utilities could enter into a long-term contract for the output of the facilities, and could also explore an equity stake or outright ownership of the facilities directly with the successful bidder.

The Working Group recommends that the Department of Public Service approach the eventual owner of the dam facilities to ascertain interest in a long-term PPA with the inclusion of a provision for purchase of all or some equity stake in the dam facilities. This option would not lock in the State into purchasing the dam facilities but would instead provide time for sufficient public input into such a purchase and a more complete analysis. In making this recommendation, the Working Group is aware that the resources necessary to make such a purchase would be significant. Further, any PPA would need to clearly provide a benefit to Vermont ratepayers and would need to be pursued in consultation with the State's electric distribution utilities to ensure that such a commitment matches the power supply needs of the utilities.

BACKGROUND

A. FORMATION OF THE VERMONT HYDROELECTRIC POWER ACQUISITION WORKING GROUP

On May 25, 2016, Act 130 was signed by the Governor.[1] Included in Section 3 of the Act is the creation of a Vermont Hydroelectric Power Acquisition Working Group. The Working Group consists of seven members:

> (1) the Secretary of Administration or designee who shall serve as chair; (2) the State Treasurer or designee; (3) the Commissioner of Public Service or designee; (4) two persons chosen by the Governor, at least one of whom shall be an employee of a regional planning commission serving communities that host at least two hydroelectric facilities owned by TransCanada Hydro; (5) one person chosen by the Speaker of the House; and (6) one person chosen by the Senate Committee on Committees.[2]

Act 130 requires the Working Group to:

> (1) Review and study the principal policy, economic, environmental, and engineering issues involved in a purchase of the dam facilities, including:
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> (A) the administrative and structural options for the ownership of the dam facilities and the sale and distribution of their power output, including ownership through the creation of a limited purpose State public power authority, the Vermont Public Power Supply Authority, by one or more Vermont utilities, or by a public-private partnership; and
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> (B) the alternatives for disposition of the power output of the dam facilities, including wholesale and retail sales within and outside the State and use of the power within a portfolio to support advanced and renewable energy technologies, and the impacts of these alternatives on the credit-worthiness of the State and the ability of Vermont utilities to access investment capital on reasonable commercial terms.
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> (2) Prepare recommendations on the purchase of the dam facilities.[3]

[1] See, Act 130, Sections 3-5, with Sec. 4 codified in 30 V.S.A. §§ 8040-8052) (2016).
[2] Act 130, Section 3(b).
[3] Act 130, Section 3(c).

Pursuant to the Act, the Working Group shall submit a report by August 1, 2016 to relevant Senate and House committees.

B. SUMMARY OF TRANSCANADA ASSETS FOR SALE

TransCanada is buying Columbia Pipeline Group for $10.2 billion and is looking to sell its northeast generation assets in order to finance the purchase. The assets for sale include the following:

<u>Hydroelectric Assets</u>

Hydroelectric Station / Water Storage Reservoir	Capacity (MW)	In Service	Location
Connecticut River Facilities			
Second Connecticut Lake Dam	Storage only	1914	Pittsburg NH
First Connecticut Lake Dam	Storage only	1915	Pittsburg NH
Moore Station	192	1957	Littleton NH & Waterford VT
Comerford Station	167	1930	Monroe NH & Barnet VT
McIndoe Station	11	1931	Monroe NH & Barnet VT
Wilder Station	41	1950	Lebanon NH & Hartford VT
Bellows Falls Station	48	1928	Walpole NH & Rockingham VT
Vernon Station	36		
Deerfield River Facilities			
Somerset Dam	Storage only	1911	Somerset VT
Searsburg Station	5	1925	Searsburg VT
Harriman Station	41	1925	Readsboro & Whitingham VT
Sherman Station	6	1927	Rowe & Monroe MA
Deerfield No. 5 Station	14	1974	Rowe & Florida MA
Deerfield No. 4 Station	6	1913	Buckland & Shelburne MA
Deerfield No. 3 Station	7	1912	Buckland & Shelburne MA
Deerfield No. 2 Station	7	1913	Conway & Shelburne MA

Given that the facilities are located in a series on the Connecticut and Deerfield Rivers, the individual units can be operated as effectively two generating resources rather than 13 distinct generators. Accordingly, there is a very significant disincentive for the owner to sell individual units. In addition to the actual dams and powerhouses, there are approximately 30,000 acres – located in Vermont, New Hampshire, and Massachusetts – associated with the hydro facilities.

In addition to the hydroelectric facilities, TransCanada is selling the following generation assets in the Northeast.

Plant	Fuel Type	Capacity (MW)	In-Service Date	Location
Ocean State Power	Natural gas and #2 fuel oil	560	1990, 1991	Burrilville, RI
Ravenwood Generating Station	Natural gas, fuel oil, kerosene	2,480	1963, 1964, 1965, 2004	Queens, NY
Ironwood Power Plant	Natural gas	778	2001	Lebanon, PA
Kibby Wind Farm	Wind	132	2010	Kibby, ME

In addition to the physical assets, the sale includes TransCanada Power Marketing, which provides retail electricity supply and demand response in restructured states. It has a retail portfolio that consists of large commercial and industrial customers with over 1,000 MW of load.

Act 130 limited the scope of this report to reviewing the potential purchase of only the hydroelectric assets, and the possibility of acquiring the fossil-fuel-fired generators and the power marketing firm are not considered.

C. PROCESS FOR THE TRANSCANADA SALE

TransCanada is a publicly traded corporation and is therefore obligated to conduct an open solicitation process that results in the maximum value from the sale of the assets. TransCanada has informally indicated that it is willing to consider selling the hydro assets separately, although they have made clear that that they will not carve out individual stations from this category. TransCanada has engaged JP Morgan to conduct the sale and the sale is expected to be conducted through the following multiple steps.

On May 26, JP Morgan sent to interested parties a brief description of the assets for sale and also a non-disclosure agreements that bidders must sign before gaining access to any additional information, including details on the process such as the deadline for submitting an initial bid. Once a bidder signs the non-disclosure agreement, it would not be able to prepare a bid with another bidder absent approval from TransCanada, and a representative of JP Morgan indicated informally that the process of approving would likely take longer than the process for submitting a bid.

JP Morgan will only send the description and non-disclosure agreement to the principal of an entity that can demonstrate that they have access to capital. Based on a discussion with a representative of JP Morgan, the State would need to have the head of the HydroElectric Power Authority contact JP Morgan and explain the financing ability of the authority before the State could receive the non-disclosure agreement. Further, the non-disclosure agreement would not provide the ability for a public entity to make exceptions for state public records law.[4]

From that point there will be a two-stage bid process. In the first stage, bidders submit an indicative bid. After review, TransCanada will select some subset of the bidders from the first stage that are then allowed to conduct additional due diligence, such as physical review of the assets, review of employee contracts and other personnel records, etc. After this review, the short-list of bidders submit a second, more detailed offer. TransCanada can select one or more bidders to begin a round of final negotiations. Since TransCanada is conducting this sale to raise money to purchase another company, it is expected that it will try to conduct the process relatively quickly.

The deadlines for submitting the initial and final bids are not public and can only be obtained through signing a non-disclosure agreement. There have been informal indications that the initial bids were due in mid-July, with final bids likely due in September.

Regulatory approval for the sale of the assets must also be obtained from the Federal Energy Regulatory Commission, the Vermont Public Service Board, and possibly regulatory agencies in New Hampshire and Massachusetts.

ADMINISTRATIVE AND STRUCTURAL OPTIONS FOR OWNERSHIP OF THE DAM FACILITIES

A. FULL STATE OWNERSHIP

The State, through the Vermont HydroElectric Power Authority created in Act 130, could purchase the hydro facilities outright.

Pursuant to Act 130, the Hydro Authority would have:

> the authority to finance, purchase, own, operate, or manage any interest in the hydroelectric power facilities along the Connecticut and Deerfield Rivers located in Vermont, New Hampshire, and Massachusetts, and to sell the electric energy under the control of the Authority from those facilities at wholesale to authorized wholesale purchasers. The purchase and operation of an interest shall be pursued with the following goals
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> (1) to promote the general good of the State;
>
> (2) to stimulate the development of the Vermont economy;

[4] H. 577 does include a provision that allows for commercial and financial information to be exempt from the Public Records Act.

> (3) to increase the degree to which Vermont's energy needs are met through environmentally-sound sustainable and renewable in-state energy sources;
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> (4) to lessen electricity price risk and volatility for Vermont ratepayers and to increase system reliability;
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> (5) to not compete with Vermont utilities;
>
> (6) to ensure that the credit rating of the State will not be adversely affected and Vermont taxpayers will not be liable should the purchase of the facilities fail because of the failure to produce sufficient revenue to service the debt, the failure of a partner, or for any other reason; and
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> (7) to cause the facilities to be operated in an environmentally-sound manner consistent with federal licenses and purposes.[5]

Oversight for the Authority would be by seven directors: five appointed by the Governor, the State Treasurer, who serves ex officio, and a representative of the Department of Public Service, appointed by the Commissioner, who shall serve at the pleasure of the Commissioner.[6] In addition, the Hydro Authority "shall employ and compensate a manager who shall serve under a contract for a specific term or at the pleasure of the Authority."[7] The Hydro Authority would be able to issue bonds, enter into contracts, employ personnel, and other related authorizations needed to own and operate the dam facilities.[8]

In addition to the Hydro Authority, the Vermont Public Power Supply Authority is another entity that is authorized under statute to own and operate facilities such as the TransCanada hydro resources. VPPSA has broad authority under 30 V.S.A. Chapter 84 to acquire facilities. However, State oversight of the dam facilities, if owned by VPPSA, would be limited; discretion over VPPSA's actions is held by its Board of Directors, which consists of appointees from each of the member municipalities or cooperatives. If a goal of having state ownership of the dam facilities is greater state control over the operation of the facilities and associated lands, the VPPSA model would need to be legislatively changed to alter the composition of the Board of Directors. Given the legislative authorization of the Hydro Authority, it is unclear that changes to the long-standing VPPSA model are worthwhile if the only purpose is to identify an appropriate entity to own and manage the dam facilities.

A significant benefit of state control over the dam facilities is the ability to exercise direct control over the resource and associated lands. While the state has the ability to provide significant input into the management of the facilities through the federal licensing process (described further in Section V.B and Appendix B, below), it has very limited authority to

[5] 30 V.S.A. § 8040(b).
[6] 30 V.S.A. § 8043.
[7] 30 V.S.A. § 8044.
[8] 30 V.S.A. § 8046.

actually require any changes to the operation of the facilities or the management of the associated land outside of the relicensing process. This raises issues such as:

(1) How would the State manage the assets differently than a private entity seeking to maximize profit from power production capability of the facilities?

(2) To what extent would State management that differs from a private entity influence the economics of owning the assets?

(3) Would the State want to have direct control over assets that are also located in New Hampshire and Massachusetts?

In order to determine whether State ownership would be beneficial, it would be necessary to more fully understand the management objectives and how these objectives would impact the economics of any purchase. A vague statement to the effect that the dams should be managed to balance the objectives of renewable energy production and water quality management does not provide any meaningful guidance. For instance, the economics of a purchase primarily directed toward maximizing renewable energy production would be more favorable than if the primary purpose is to maximize water quality benefits. Once such a priority is made, it will drive the economics of the purchase and subsequent management, and any drastic change in management from that initial guidance could potentially have significant impacts on the economic viability of the assets or the environmental decisions made regarding the water resources.

Ownership of the facilities would also mean that the State assumes liability for dam safety and also incurs relicensing costs (which would also be subject to regulatory agencies in New Hampshire and Massachusetts).

Act 130 provides the HydroPower Authority with the ability to bond for the acquisition of the facilities.

As discussed below, the State's consultant estimates the economic value of the dam facilities to be in the range of $975 million to $1.376 million. Without an obvious alternative source, the State would need to issue debt for any acquisition cost (plus working capital). The State's existing outstanding tax supported debt is $637 million. If Vermont's direct or moral obligation debt is used to finance the dam facilities it would seriously impair the State's future debt capacity and affordability. It is Treasurer's view that there is a strong possibility that the State could lose one or more of its triple-A ratings, and this would increase the State's cost to raise capital funds for many years to come. Alternatively, the State could create an enterprise fund type structure where only the electric utility revenues are available to pay debt service. However, the financial risks to the State could be substantial as it is not a core function of the State to go into the electric generation business. There is a risk that rating agencies will be concerned with the State participating in a large financial venture that has private business risk with which the State has little direct experience. There is a risk that future regulatory changes could affect revenues available for debt service and these revenues may not be sufficient. Unanticipated events such as natural disasters, new regulations, technology changes, terrorist activities, etc., could increase the State's operating expenses and need for capital. It is not certain that a new independent authority would have access to capital markets to fund the requirements. Investors and the rating agencies are becoming more focused on governments taking large business financing risks even when the debt is assumed to be self-supporting.

B. Public-Private Partnership

Under this model, the State of Vermont would acquire some level of ownership, although it would not be sole owner. A partnership can have multiple forms: a percent equity share of all assets or some subset, ownership in some subset of products, an agreement with one or any number of partners, etc. Typically, a 10% or greater share in ownership would be necessary in order to have a seat on the board and ability to influence decisions. A common element of all the partnership models is that Vermont incurs both benefits and liabilities related to ownership. Accordingly, appropriate due diligence would be required before entering into a partnership.

A Vermont presence (either the state or a distribution utility) has some intangible benefits associated with potentially demonstrating public support for the regulatory process; however, a partnership increases the complexity of the acquisition and it's unlikely that regulatory approvals will be particularly difficult to obtain. Additionally, the State should expect to incur very significant legal expenses involving the structuring of any partnership agreement as outside counsel with specific mergers and acquisition experience would need to be retained.

The benefit of a private/public partnership is that the partner would presumably bring experience of operating and maintaining hydro assets. Additionally, depending on the structure of the partnership, the State of Vermont would presumably have some ability to influence the management of the assets for energy, environmental, and recreational purposes.

C. Ownership by Vermont Utilities

Unlike the other New England states, Vermont's electric distribution utilities remain vertically integrated, which means that they can own and enter into long-term contracts for generation.[9] Many of Vermont's utilities own generation assets, including a large number of hydroelectric plants, and Vermont's utilities jointly own the McNeil biomass generating station. The total amount of generation owned by the Vermont utilities is less than that of the dam facilities, and the acquisition of the assets would be a significant increase in the rate base of the Vermont utilities. By way of example, the total rate base investment of Green Mountain Power Corporation, as of March 2015, is approximately $1.2 billion, which includes all of the assets, including poles, wires, substations, and physical facilities. GMP serves approximately 78% of the State's total load; the other distribution utilities have much smaller rate base investments.

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[9] Municipally and cooperatively owned electric utilities in most other New England states are also allowed to own generation and enter into long-term contracts as these utilities are not subject to the restructuring that occurred in most New England states.

Despite the large size relative to its existing rate base, Green Mountain Power Corporation would likely be able to finance the acquisition on reasonable terms. Prior to withdrawing ratings in 2013, Moody's had given Green Mountain Power and Central Vermont Public Service each an 'A3' first mortgage bond rating and 'Baa2' issuer rating. In December 2015 Standard and Poor's gave GMP an issuer credit rating of 'A-' and an 'A' senior secured issue rating on its long-term senior secured debt. The recent financial performance of the company indicates that its credit position is stable if not improving. Recent utility deals have typically been credit neutral because they have been financed with a balanced mix of debt and equity.

Ownership of all the assets by any of the other Vermont utilities, on an individual basis, would be a very large investment, would be difficult to finance and would likely have an adverse impact their credit position. Vermont's smaller electric distribution utilities could enter into a partnership with each other and/or the state to acquire an interest in the assets.

D. Power Purchase Agreement with Eventual Owner

An acquisition model not contemplated under Act 130 is a Power Purchase Agreement (PPA). Under this model, the State of Vermont would have an ownership interest in the output of the assets (energy, capacity, and RECs) but would not have any ownership interest in the assets themselves.

A stably and beneficially priced long-term power purchase agreement for the output of the hydro assets – primarily capacity, renewable energy credits, and energy – has the potential to provide benefits to Vermont ratepayers. Such an arrangement would not provide any immediate opportunity for oversight over the operations and management of the assets and associated land; however, it may be possible to include a provision in a PPA that allows for the eventual purchase of the assets or at least provides an option for first refusal in the event of the sale of the assets. To the extent that the eventual owner is willing to include such a provision in a PPA it would provide a more reasonable time frame for consideration of whether acquisition of the assets is in the best interests of Vermont.

The State could enter into a PPA either through the Hydro Authority or through the Department of Public Service. It's unclear whether there would be sufficient benefits to creating and staffing the Hydro Authority solely to execute and manage a PPA. Alternatively, the DPS has two options under existing statute to enter into power purchase agreements with the eventual owner of the assets. Under Section 211, the DPS may enter into contracts with generators and utilities have the option of purchasing from the Department. This is the mechanism used to purchase power from the New York Power Authority. Additionally, under Section 212a, the Department may enter into contracts and then sell the power directly to retail customers. Apparently this mechanism was used to purchase preference power from NYPA and distribute it to Vermont's investor-owned utilities (certain portions of NYPA power is only available to publically owned utilities); the DPS had voluntary arrangements with the utilities where they would sell directly to specific customers.

Individual utilities could also enter into PPAs with the eventual owner of the assets. One benefit of having the State enter into the PPA is that the owner would be dealing with one contractual party; however, utilities have worked out individual contractual arrangements with sellers in previous circumstances, both jointly[10] and individually.[11]

Utilities can enter into PPAs for energy, capacity and RECs from any eligible resource in New England. Regarding energy, the wholesale market has become the standard against which the reasonable price of energy is compared. The underlying assumption is that markets produce the most economically efficient outcome, i.e., reasonably lowest, price over the long-term. This is intuitive because the seller wants to hedge against future market prices being lower while the buyer wants to hedge against future market prices going higher. Vermont utilities already have a much higher percentage of their energy requirements hedged against market price volatility than any other state in New England.

A PPA for the dam facilities could be beneficial at a time where market prices are low—as it could provide an opportunity to lock in the lower prices. Energy prices are easier to foresee, at least in the short-term. In New England, natural gas generation sets the price in many hours, i.e. is the marginal resource. Therefore, the price of natural gas is a key determinant of the price of all resources will get from the market. It is expected that, due to continued shale gas production, natural gas prices will continue to remain low for the foreseeable future.[12]

Although energy is well hedged, the Vermont utilities have significantly greater open positions with respect to capacity. This is in part due to the fact that Vermont utilities obtain a significant amount of energy from intermittent resources such as wind facilities; such intermittent facilities tend to have low capacity values compared to nameplate capacity. Energy and capacity prices, in theory, should complement each other though in practice the two are not highly correlated. Capacity prices, in particular, are difficult to predict as they tend to spike or dip from year-to-year. In recent years, in New England, energy prices have been low while capacity prices spiked in the three most recent forward capacity auctions. If more reserves are available and/or load forecasts decrease further then it's possible that capacity prices will dip in the next auction. The expectation of where capacity prices will go could also determine whether a long-term contract is beneficial.

Entering into a long-term contract is a decision to lock-in prices for meeting expected load requirements. There is an associated risk that the prices contained in the PPA could be significantly higher than the prices that could be obtained for the products on the market. Additionally, the amount of load, and therefore energy and REC requirements can change for reasons outside a utility's control. For example, a permanent loss of load could result in the need for the utility to sell the hedged amount of energy and RECs into the market, potentially at a loss.

[10] *See,* e.g., Public Service Board Docket 7670, Order of 4/15/11, approving a PPA between twenty Vermont utilities and H.Q. Energy Services (U.S.) Inc.

[11] *See,* e.g., Public Service Board Orders re Vermont utility PPAs with NextEra Energy Seabrook, LLC (Docket 7742, Order of 11/4/11; Docket 7814, Order of 1/19/12; Docket 7815, Order of 3/9/12; and Docket 7872, Order of 10/31/12).

[12] Due to natural gas pipeline constraints, gas prices and consequently electric prices are expected to see price spikes during periods of cold weather when natural gas is used for heating.

Inversely, hedging load could result in lower prices than market. Regardless of what the market does, a PPA provides price certainty and reduces price volatility.

E. Power Purchase Agreement with Option to Purchase

One possible addition to a PPA is an option to purchase some stake in the facilities at a future date. Under this approach, a clause would be included in the PPA that provides the State or Vermont utilities with the right of first refusal in the event that the assets are sold, and would provide specific dates (e.g., at the end of the contract period or every five years from the date of execution) at which time the State or Vermont utility could negotiate the purchase price for an equity stake or complete ownership of the assets. This would provide the State sufficient time to fully consider and address whether ownership is in the interests of the State. In order to complete a purchase option, a full analysis of the value of the assets would be needed at the time the option is exercised.

This model is not unprecedented, and in fact the City of Burlington Electric Department (BED) purchased Winooski One, a 7.4 MW hydroelectric facility, through such a clause in a PPA between BED and the hydro owner. The contract provided that BED would pay the fair market value of the project at the expiration of the 20-year PPA. As BED and the prior owner could not agree on the fair market value, the parties entered into arbitration and the process required significant resources on the part of BED in order to accomplish the purchase.

It is unclear whether the next owner of the dam facilities would be interested in including such a provision in the contract. Similar to a PPA, such a provision would only provide a benefit if the price is right. As with every other arms-length transaction, the seller and buyer will each attempt to maximize the benefits received and both parties will need to be able to walk away from the deal if the benefit is insufficient.

Economic Value of the Hydro Assets

A. Expected revenue from wholesale electricity markets

The State contracted with Synapse Energy Economics to perform an economic valuation of the dam facilities, included as Attachment A to this report. This section provides an overview of the factors that are considered in the valuation of the facilities.

The value of a generation resource is largely dependent on the payments that it can receive through the wholesale electricity markets administered by ISO New England (ISO-NE) and regulated by the Federal Energy Regulatory Commission, as well as the costs of operation and maintenance. There are four main payment streams that a hydroelectric resource can receive:

Energy

Measured in MWh, this value will depend on the time of day and year that the energy is being generated. Wholesale energy prices are typically higher during peak hours of the day and during winter and summer months. An estimate of the revenues received from the energy market will depend on the timing of the hours that the energy is produced (peak/off-peak hours, summer, winter, and shoulder seasons) and also the estimated wholesale price of energy at that time. While historical average monthly production values can provide some measure of the expected revenue, it is difficult to project with any measure of certainty the expected wholesale energy price. In addition, the amount of energy produced is a result of rainfall and therefore changes considerably from month to month and year to year, with the effect of climate change on rainfall patterns creating further uncertainty. These factors, along with the likely changes in the timing of generation as a result of the relicensing process, will present challenges as to expected energy market revenues.

Additionally, in the past few years ISO-NE has implemented negative pricing, in which a generator that is producing power during off-peak, low load hours must pay to continue generating. Intermittent resources, which are unable to time the production of energy, are more likely to experience negative pricing.

Capacity

This is the maximum instantaneous amount of energy that a resource is expected to deliver during the hour when the New England system is at peak load (typically during the hottest day of the summer) and in the New England wholesale market capacity is measured in kW-month. Unlike energy sales, the value of the assets as capacity supply resources is known with some certainty through the next few years as ISO-NE makes public the capacity supply obligation of every resource receiving capacity payments, and the single clearing price for capacity in that period. The relicensing process would likely result in some reduction in the value of the Wilder, Bellows Falls, and Vernon facilities as capacity supply resources.

Renewable Energy Credits

Every MWh produced by a renewable resource results in creation of one REC. The value of a REC can vary considerably by the age and technology type of resource. The market value for a REC from a wind or solar projects commissioned within the past 10 years is approximately $60. In comparison, the market value of a REC from a 50-year old hydroelectric unit will likely be around $10. Given the age and size of the facilities, most of the RECs produced would likely be of relatively low value, but would be eligible for the Vermont Renewable Energy Standard Tier 1 requirements.[13]

[13] As noted in the Synapse report, a portion of the output from the Vernon and Comerford facilities are eligible for the higher priced RECs.

Ancillary Services

In order to maintain reliability, ISO-NE provides payment streams for resources that can provide specific services. The ancillary services that these facilities might provide include black start capability (the ability to begin generating electricity even in the event of a blackout) and frequency control (the ability to quickly ramp output up or down to respond to changes in load). For most resources, ancillary services provide a small percentage of total revenues and therefore such resources were not studied in the Synapse report.

The proportional value of the revenue streams described above will depend on the specific characteristics of the asset. For example, older oil-fired units seldom produce energy and rely primarily on capacity and some ancillary payments. An intermittent resource will typically receive most of its revenue from energy revenues with a smaller portion of revenues from capacity payments.

B. EXPECTED COSTS

Given that there are no fuel costs associated with the hydro resources, the costs of owning the dam are primarily a function of taxes, operation and maintenance, including regulatory costs. In terms of operations and maintenance, the costs relate to the age of the assets and any upgrades related to environmental obligations (e.g., fish passage and minimum water flow). TransCanada has upgraded some of the related transmission infrastructure since purchasing the assets,[14] however, the conditions of the dams and generating stations are not known. Detailed information regarding asset conditions would be expected to become available during the bidding process once a non-disclosure agreement is signed. Regulatory costs can be significant as well, particularly as three of the dams are currently undergoing relicensing and the remaining dams will need to undergo the process within the next 25 years.

C. ESTIMATED VALUE OF THE TRANSCANADA HYDRO ASSETS

Given the factors notes above, Synapse Energy Economics estimated the value of the dam facilities at $981,000,000 to $1,364,000,000. This is only an estimate and there is information that is not available but is necessary to provide a more precise estimate with a greater degree of confidence. In particular, it is difficult to estimate the economic impacts associated with the relicensing of the Wilder, Bellows Falls, and Vernon facilities and subsequent changes to operations of these facilities. In addition, specific maintenance costs were not available to Synapse Energy Economics.

[14] The work performed was subject to review by the Public Service Board and the resulting PSB orders are public.

POLICY CONSIDERATIONS ASSOCIATED WITH PURCHASING THE DAM FACILITIES

A. ENERGY ISSUES

Regulatory Oversight of the Hydroelectric Assets

Generally, wholesale energy and capacity rates (the rates paid to generators by distribution utilities) and transmission rates are under the jurisdiction of the Federal Energy Regulatory Commission (FERC). In addition, siting determinations associated with most hydroelectric facilities are made by FERC. State entities such as the Public Service Board are responsible for retail rates (the rates by electric end-use customers to the distribution utilities) and for siting of transmission and most generation facilities.

Federal

Under Sections 205 and 206 of the Federal Power Act, the Federal Energy Regulatory Commission has authority to ensure that wholesale rates (the rates paid to generators by distribution utilities) are just and reasonable. At this point, FERC largely defers to the competitive wholesale markets run by ISO-NE to ensure that rates are just and reasonable – FERC is responsible for approving the design of and changes to the markets. In order to effectively operate the facilities any owner will be responsible for fully understanding the wholesale markets administered by ISO-NE. The rules for the market are spelled out in over 400 pages and are subject to constant revision through a structured stakeholder process where any changes to the rules must be approved by FERC. Even if the output from the assets are sold directly to Vermont utilities or are operated directly by Vermont utilities, the facilities must participate in these markets. In addition, the purchaser of the dam facilities must obtain from FERC authority to sell at market-based rates (effectively to be able to participate in the wholesale markets).[15]

Under Section 203 of the Federal Power Act, FERC must approve disposition of any generation assets. Section 301(c) of the Act provides FERC "authority to examine the books and records of any person who controls, directly or indirectly, a jurisdictional public utility insofar as the books and records relate to transactions with or the business of such public utility."[16]

FERC is also responsible for ensuring the safety of the dams, including periodic evaluation and oversight of Emergency Action Plans and Public Safety Plans.[17] Finally, the dams and associated lands are subject to FERC licenses. Any change in the operation of the dams, as well as changes to the management of lands for recreational purposes, would be subject to review under the FERC licensing process.

[15] FERC Orders 697, 816, 652.
[16] *See* 152 FERC ¶ 62016 at 4.
[17] See FERC's overview of the process at http://www.ferc.gov/industries/hydropower/safety.asp.

Vermont

The Vermont Public Service Board has general authority under Title 30 to regulate electric generation companies doing business in Vermont. Under 30 V.S.A. § 109 before a company can transfer certain generation and transmission assets, the PSB must first find that the transfer promotes the general good of the state. Similarly, the PSB must determine under 30 V.S.A. § 231 that the operation of a business under the PSB's jurisdiction will promote the public good before a company can do business in Vermont.

The regulatory oversight of the State's power supply portfolio is generally conducted through 30 V.S.A. § 248. This law requires approval from the PSB before any new generation resource in the state is constructed and also approval of certain long-term contracts and investments that Vermont's electric distribution utilities enter into related to out-of-state generation and transmission facilities. In addition, the PSB reviews all power purchase agreements and capital purchases in the context of rate setting proceedings and can disallow utility costs that were not prudently incurred.

With respect to the siting aspect of Section 248, TransCanada has received PSB approval for certain changes to transmission infrastructure associated with the assets; presumably the future owners would need to obtain approval for any similar upgrades.[18]

To the extent that a Vermont distribution utility enters into a long-term contract with the new owner of the assets for a period greater than ten years and representing more than ten percent of its historic peak demand, the utility would be required to obtain approval under Section 248 from the PSB. This requirement only applies to a contract for output from out-of-state facilities, and therefore a utility could conceivably enter into an arrangement that involved only facilities located inside Vermont without triggering the Section 248 requirement.[19] There are two facilities on the Deerfield River – Harriman and Searsburg – that are fully within Vermont, for a total capacity of 46 MW. Additionally, while the dams of the facilities on the Connecticut River are mostly in New Hampshire, the powerhouses of some of the facilities are located within Vermont; the PSB would have to determine whether Section 248 applied in such a circumstance. Section 248(a)(1)(B) states that no Vermont utility may "invest in an electric generation or transmission facility located outside this State unless the Pubic Service Board first finds that the same will promote the general good of the State and issues a certificate to that effect." To the extent that a Vermont utility acquires any ownership interest in the facilities, other than the ones located in Vermont, the utility must first obtain a certificate of public good from the PSB.

If a Vermont utility acquires an ownership interest or even enters into a PPA with the new owner, State involvement in an acquisition or PPA has the potential to create a conflict regarding regulatory review of the acquisition or PPA. The DPS is responsible for "representing

[18] There would need to be further exploration of whether the transmission facilities are covered by the FERC license and therefore exempt from the PSB's jurisdiction.
[19] It is important to note, however, that the PSB has general jurisdiction under 30 V.S.A. § 209, and could if it so chose open an investigation into any contract that a Vermont utility entered into.

the interests of the people of the State"[20] before the PSB. To the extent that the DPS, through membership on a HydroPower Authority or other mechanism, is involved in the acquisition or PPA, it would not be an independent third party. However, such a situation has arisen before in the context of a PPA, and there are relatively straightforward mechanisms for addressing the potential conflict. For example, when the DPS exercises its authority to resell power under Section 212a, the Attorney General or a member of the Vermont bar is requested by the PSB to represent the interests of the public.[21] Alternatively, the DPS could decline to participate in any State acquisition or PPA through a walling-off of membership on the HydroPower Authority.

Relevant Energy Policy

In order to determine whether an ownership interest in the facilities provides a benefit to Vermont, it is important to review relevant state policies, including specific statutory enactments and the 2016 Vermont Comprehensive Energy Plan.

30 V.S.A. § 202a. – State Energy Policy

> It is the general policy of the state of Vermont:
>
> (1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost effective demand side management; and that is environmentally sound.
>
> (2) To identify and evaluate on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least cost integrated planning; including efficiency, conservation and load management alternatives, wise use of renewable resources and environmentally sound energy supply.

The general State energy policy is broadly written and provides significant flexibility with respect to how this section should be implemented in practice. It makes clear that environmental considerations should be accounted for in decision making, but does not provide specific guidance as to how different considerations should be weighted in balancing potentially competing goals. For example, "environmentally sound energy supply" suggests that hydroelectric facilities should be operated to balance the impact to the river with production of renewable energy. This could include voluntarily implementing operations to maximize water quality uses for all state-owned hydroelectric facilities, which would reduce the renewable output and economic value of the facilities. Alternatively, it could mean that the facilities should be operated to maximize the output of renewable generation, regardless of the impact on water quality, in order to minimize regional greenhouse gas emissions. Policy preferences have

[20] 30 V.S.A. § 2(b).
[21] 30 V.S.A. § 212e.

changed considerably over the 100 years since the facilities were first constructed, and will likely continue to change in the future.

30 V.S.A. § 8001 – Renewable Energy Goals

Section 8001 sets forth policy goals that should be pursued in order to implement Section 202a. Listed below is each of the eight specific renewable policy goals along with a brief summary of how acquisition of the dam facilities might further the goals.

> *Section 8001(a)(1). Balancing the benefits, lifetime costs, and rates of the State's overall energy portfolio to ensure that to the greatest extent possible the economic benefits of renewable energy in the State flow to the Vermont economy in general, and to the rate paying citizens of the State in particular.*

This provision appears to assume that renewable resources will be the most economically cost-effective resource over the long-term and encourages the incorporation of these resources into utilities' power supply portfolios. To the extent that acquisition of the dam facilities is in the economic interest of Vermont, i.e., that acquisition would in the long-term be less expensive than purchasing power on the ISO-NE market, purchasing alternative generation sources located elsewhere in New England or constructing new generation, such acquisition would be consistent with this provision.

> *Section 8001(a)(2). Supporting development of renewable energy that uses natural resources efficiently and related planned energy industries in Vermont, and the jobs and economic benefits associated with such development, while retaining and supporting existing renewable energy infrastructure.*

This provision is primarily directed to the development of new renewable infrastructure and the resulting economic benefits. However, the language also recognizes that there are benefits to maintaining existing renewable resources. The Vermont Comprehensive Energy Plan also specifically discusses retention of existing renewable resources:

> Meeting long-term renewable electricity and energy goals requires maintaining existing renewable electric generation in Vermont, in addition to the development of new resources. Because many generators now online have been fully depreciated or have paid off loans related to their construction, they can often be cost-effectively maintained and operated at costs at or below the cost of new generation. Many older facilities are hydroelectric generators, and occupy a large fraction of all of the potential dam sites for

> hydroelectric generation. The loss of such systems could result in an irreversible loss in in-state hydroelectric generating capacity.[22]

To the extent that any entity purchases the dam facilities, the intent is likely to retain the facilities for renewable production; consequently, acquisition by the State is likely not needed to maintain the dam facilities. Further, the State has previously required that specific categories of resources be granted PPAs,[23] and a similar approach could be taken to maintain these facilities if the State determines that such action is necessary at some future point.

> *Section 8001(a)(3). Providing an incentive for the State's retail electricity providers to enter into affordable, long-term, stably priced renewable energy contracts that mitigate market price fluctuations for Vermonters.*

Vermont electric utilities are still vertically integrated, meaning that they can own and/or enter into long-term contracts for generation. Most regulated electric utilities in New England had to divest generation and power purchase agreements when the states in which they were located restructured. Municipal and cooperative utilities in other states are not typically regulated in the same manner as investor-owned utilities and were not required to divest during restructuring.

The Vermont electric utilities currently have significant long-term contracts or own generation directly. The extent to which individual utilities are hedged against market price fluctuations varies, with some utilities 100% hedged against the market while others have a number of long-term contracts that cover a majority of power supply obligations and then enter into contracts with terms shorter than five years in order to provide some mitigation against market price fluctuations without creating significant risk that contract prices will be significantly out-of-market.

Contract price terms can vary considerably. Common terms include: (1) a fixed price – one that may rise with inflation, but is based upon projected market prices and does not fluctuate as the market fluctuates; (2) a collared price term is one that moves with the market but the extent to which it moves is bound by some factor, such as it cannot increase or decrease by more than X% in any given year; (3) a market-indexed price term is one in which the price is directly tied to the market and can fluctuate considerably for every five-minute increment in the day.

In addition, most contracts entered into by the Vermont utilities are bundled, in that the utility purchases all of the outputs of the resources – energy, capacity and RECs (many renewable resources do not provide ancillary services.)

Depending on the structure, an acquisition of the TransCanada assets could provide the same effect of mitigating market price fluctuations for ratepayers. The downside of such an

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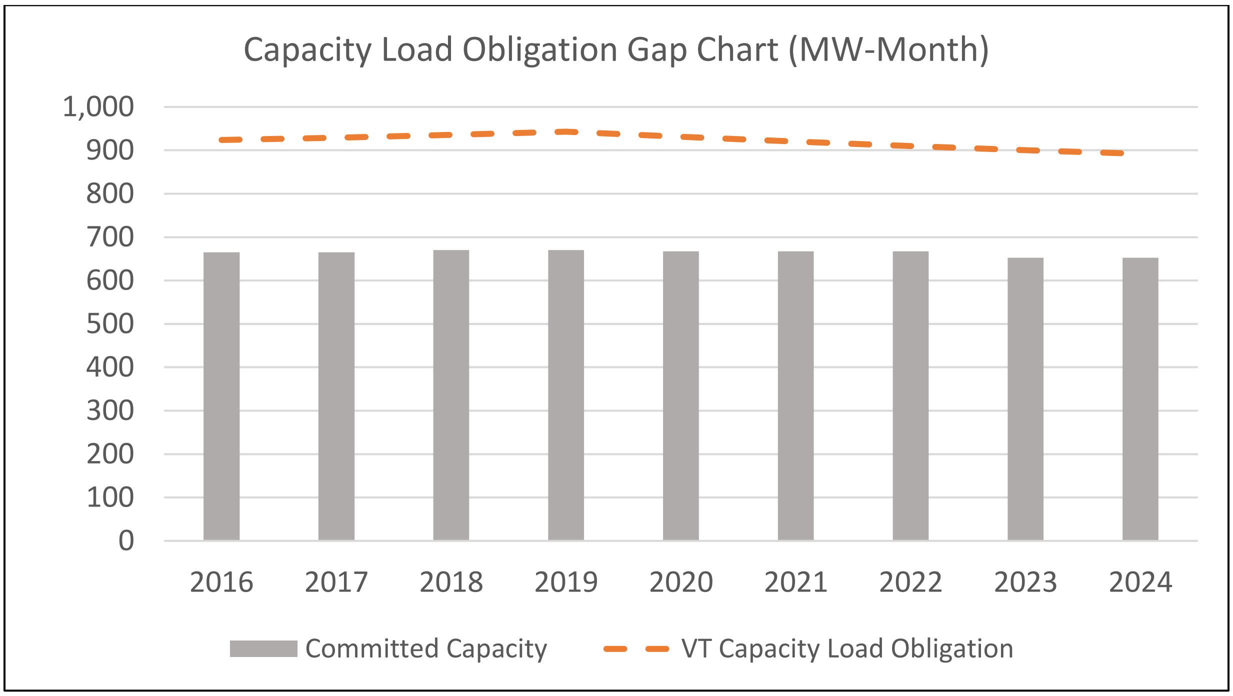
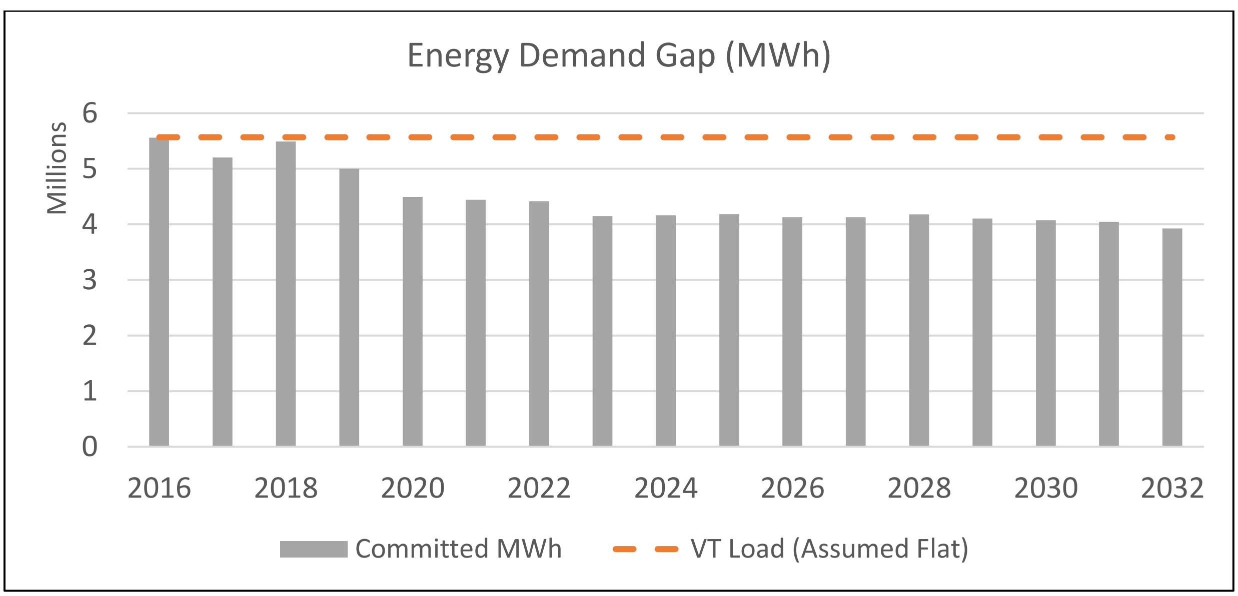
[22] CEP at 261.
[23] *See*, 30 V.S.A. §§ 8005a(p) and 8009.

approach is that the State also takes on the risks associated with ownership – such as, unexpected operation and maintenance costs, liability associated with dam safety, and changes in expectations of the amount of load or the cost of alternative power.

Currently, Vermont utilities already have a much higher percentage of their energy requirements hedged against market price volatility than any other state in New England. The graphs below represent the amount of Vermont energy and capacity needs met by long-term contracts or by utility-owned generation.





The contracts range from wind projects within Vermont to hydroelectric projects in Maine. Utilities can enter into contracts with any resource that can deliver into New England, and there is little direct economic benefit to ratepayers to entering into a contract with generation resources located within and near Vermont compared to entering into a contract with resources located elsewhere, provided that such resources are not located in transmission-constrained areas. A contract is only worthwhile if it provides economic benefits and the specifics of the contract terms would determine if the contract meets such a test.

Section 8001(a)(4). Developing viable markets for renewable energy and energy efficiency projects.

This provision is primarily intended to address development of new renewable facilities. To the extent that a large portion of the State's renewable energy is met through existing facilities, it could have the effect of reducing the incentive for development of new resources associated with Vermont's power supply needs.

Section 8001(a)(5). Protecting and promoting air and water quality in the State and region through the displacement of those fuels, including fossil fuels, which are known to emit or discharge pollutants.

In order to maximize the value of its investment, the new entity that owns the facilities will likely attempt to maximize the production of renewable energy, which in turn will displace emissions from fossil-fuel-fired generation resources. Such an economic incentive on the part of the owner appears to be well aligned with the specific language of this provision and it's unlikely that the ownership structure would significantly impact accomplishing this goal. The only scenario where ownership would likely make a difference to meeting this goal would be if the new owner chose to emphasize improvements to water quality rather than energy production.

Section 8001(a)(6). Contributing to reductions in global climate change and anticipating the impacts on the State's economy that might be caused by federal regulation designed to attain those reductions.

As noted above, it is unlikely that the operation of the dam facilities would be modified under different ownership. The incentive to maximize output of renewable energy will displace emissions from fossil-fuel-fired generation resources and thereby mitigating climate change.

With respect to impacts on the State's economy of regulations designed to reduce carbon emissions, the renewable output of the facilities are more valuable in a regulatory environment where carbon emissions have higher economic costs, e.g., through a price mechanism such as that imposed by the Regional Greenhouse Gas Initiative that Vermont and eight other northeastern states have entered into. In this circumstance, State ownership of the facilities or the renewable output would have greater value if such ownership was acquired prior to the imposition of increasingly stringent carbon emission pricing, such as a reduction in the RGGI cap or introduction of a federal carbon pricing mechanism.

> *Section 8001(a)(7). Providing support and incentives to locate renewable energy plants of small and moderate size in a manner that is distributed across the State's electric grid, including locating such plants in areas that will provide benefit to the operation and management of that grid through such means as reducing line losses and addressing transmission and distribution constraints.*

This provision is primarily directed at generation facilities of relatively small size, and also the introduction of new facilities into the grid. The dam facilities are already taken into account for planning studies. While continuing operation will have an impact to some extent on grid operation, it is highly unlikely that these facilities will not continue to operate absent State purchase.

With respect to the location of these facilities, given that the New England grid is relatively free of congestion and the wholesale markets are regulated by FERC, it's not clear that there are specific energy policies that are furthered by an interest in these assets, as compared to assets located elsewhere in New England.

> *Section 8001(a)(8). Promoting the inclusion, in Vermont's electric supply portfolio, of renewable energy plants that are diverse in plant capacity and type of renewable energy technology.*

As of 2014, Vermont's overall electric supply portfolio, before the sale and purchase of RECs, consists of 42% hydroelectric, 8% wind, 7% biomass, 4% nuclear, 2% methane, 1% solar, 1% fossil fuel, and 35% residual fuel mix (the generation mix on the ISO New England system). These proportions vary considerably by individual distribution utility.

With respect to hydroelectric resources, the single largest source is HydroQuebec, contributing approximately 25% of the energy for Vermont and under contract until 2038. Vermont utilities directly own approximately another 10%, with the remainder under contracts of varying lengths. Given the amount of hydroelectric power already in Vermont's power supply portfolio, the purchase of TransCanada's hydroelectric facilities will not significantly further the goals of increasing diversity of Vermont's overall electric supply portfolio.

30 V.S.A. § 8004 – Renewable Energy Standard

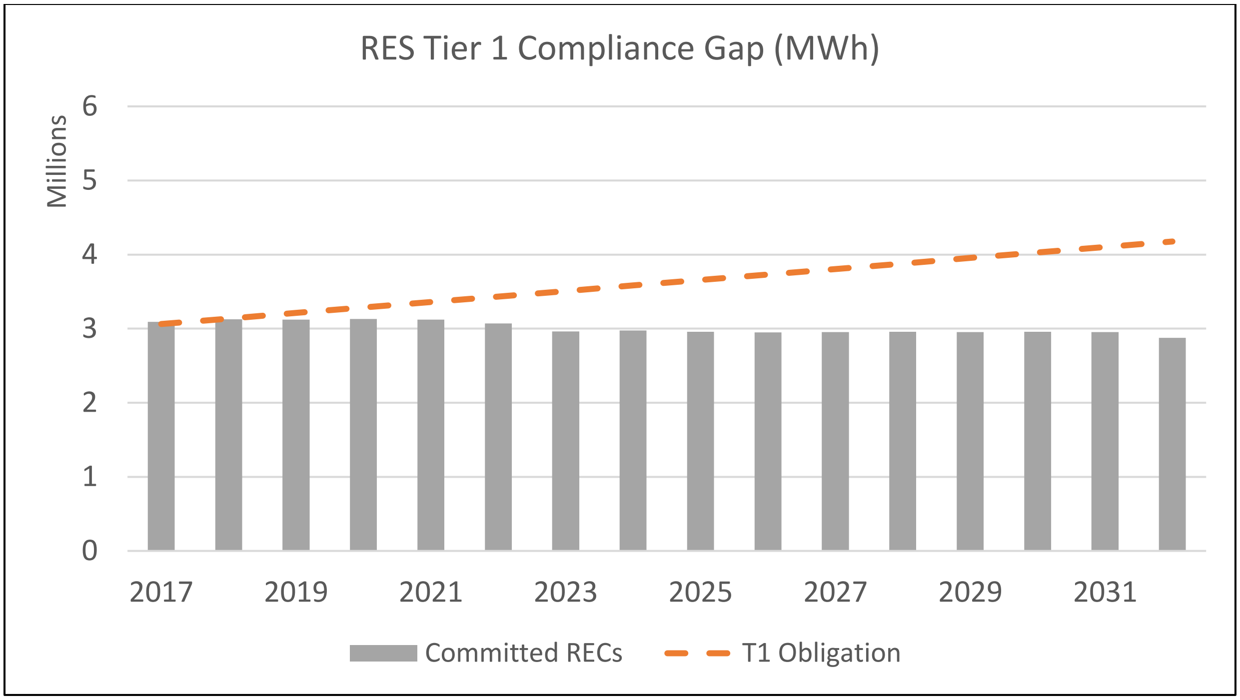
In 2015, Vermont General Assembly passed the Renewable Energy Standard (RES), which sets forth the renewable requirements that Vermont's electric distribution utilities must meet. The RES is separated into three tiers:

- Tier 1 requires that 55% of the electric power supplied to customers be renewable in 2017, increasing to 75% in 2032.
- Tier 2 requires that, by 2017, 1% of the electric power supplied to customers come from distributed renewable resources (with a nameplate capacity of less than 5 MW and placed into service after June 30, 2015) connected to Vermont's grid, increasing to 10% in 2032.
- Tier 3 requires that electric utilities reduce fossil fuel use of their customers by an amount equivalent to 2% of retail electric sales by 2017, increasing to 12% by 2032.

The RES is consistent with renewable requirements in other New England states, in that utilities must retire renewable energy credits (RECs) in order to comply with the requirements. RECs are separate attributes from energy and capacity and therefore can be traded separately. It is not uncommon for a facility to sell energy into the wholesale market and have a contract to sell RECs to a specific distribution utility. The energy associated with RECs must either be generated within or delivered into the New England system in order comply with the requirements. The benefit of RECs is that they are tradeable across the New England system; a REC created by a dam in Maine can be used to comply with the RES, just as a REC created in Vermont can be used to comply with the Maine Renewable Portfolio Standard.

The output of the hydro assets meet the eligibility requirements of Tier 1. The Vermont utilities currently have long-term contracts that are expected to meet approximately 75% of the necessary RES in 2032. The utilities could simply purchase RECs, without associated energy to meet the remainder of the RES requirement, or could enter into long-term contracts for energy and RECs. The alternative compliance payment for Tier 1 is $10/MWh, adjusted annually, starting January 1, 2018, using the Consumer Price Index.[24] This alternative compliance payment effectively sets a price cap for tier 1 RECs.

[24] 30 V.S.A. § 8005(a)(4).



Vermont utilities could purchase RECs from a large number of resources in New England or surrounding areas or, if REC prices are more expensive than the Alternative Compliance Payment, could utilize that mechanism. Ownership or having a PPA with the dam facilities is not necessary in order to comply with the Renewable Energy Standard although, depending on acquisition or contract prices, there could be an economic benefit associated with ownership or a PPA compared to purchasing RECs on the market.

30 V.S.A. § 202b – Comprehensive Energy Plan

Section 202b requires the DPS to prepare a State Comprehensive Energy Plan that covers at least a 20-year period and includes:

1. a comprehensive analysis and projections regarding the use, cost, supply, and environmental effects of all forms of energy resources used within Vermont; and

2. recommendations for State implementation actions, regulation, legislation, and other public and private action to carry out the comprehensive energy plan.

In January 2016 the DPS released the most recent version of the CEP which includes three "guiding goals when developing and evaluating energy policy:" (1) "a vibrant and equitable economy," (2) "healthy ecosystems and a sustainable environment," and (3) "healthy Vermonters."

The CEP notes the "growing pains" that have been experienced as Vermont increases the number of generating resources in response to renewable policy requirements and goals. The dam facilities, although located near or within Vermont, have seldom been under active discussion as part of Vermont's energy mix. Vermont is part of an open New England system where dams in Maine and Quebec can and do provide power for Vermont utilities. Given that the TransCanada hydro facilities are effectively two resources, with portions of the facilities located in three states, it is unclear the extent to which these resources can be considered a "Vermont resource." Additionally, there is little guidance as to how much of Vermont's renewable power supply should be provided within the State, although as a matter of basic equity it is difficult to argue that all of the externalities associated with hosting power plants should be borne in locations other than Vermont. To the extent that some or all of the dam facilities can be claimed as a "Vermont resource," the acquisition of these resources, either through ownership or a long-term PPA for the output, could be perceived as reducing the "need" to develop additional in-state renewable resources.[25] In this way, the acquisition of the dam facilities could lessen the pressure on the State's land use.[26] It is important to keep in mind that we are in an interconnected New England grid, with significant expenditures by all New England ratepayers to build a system with very limited congestion, and which consequently allows for delivery of power from generators located in most areas of Vermont, and also some resources imported into the region.

The CEP specifically references the TransCanada assets as follows:

> Some Vermonters feel that in 2003, Vermont lost an opportunity to gain ownership of and access to the eight hydroelectric dams on the Connecticut and Deerfield Rivers, with their nearly 500 MW of renewable power, when the prior owner suffered financial distress and sold the dams. The final cost of the purchase to the new owner, TransCanada — $500 million — would have added significant increased risk to Vermont's finances and, given market electric prices between 2003 and 2011, would not have been offset by savings in retail sales. Since many Vermonters value this local renewable resource, which provides some tax revenue and jobs to the state, it would be a positive step for Vermont utilities to enter into contracts for power from the eight dams, assuming that acceptable price and quantity terms could be negotiated. The state will also watch for any new opportunity to purchase these hydro facilities if they become available.

[25] It is important to consider that the Renewable Energy Standard discussed above effectively creates the need for some percentage of Vermont's load to be served from facilities that are interconnected with Vermont's distribution network, and consequently, most likely physically located within the State. This is currently the only statutory requirement regarding the amount of resources that need to be developed within the State.

[26] Other mechanisms to reduce the impact on greenfield development is currently being considered in the context of the PSB's review of the net metering requirements; such mechanisms (increased incentives for "well-sited projects") could potentially be applied in other renewable policies.

> Other hydropower resources in the northeastern U.S. may become available to Vermont utilities.[27]

This language was written before TransCanada announced that it was selling the dam facilities and there has been no further discussion on the matter until the working group was formed.

A further issue associated with hydro power specifically mentioned in the CEP is the potential ability of hydro to balance other intermittent generation: "Hydroelectric generation is variable with water flow, but varies differently over time than do other variable generators such as solar PV and wind, providing valuable diversity in in-state generation."[28] The specific monthly capacity factors, as identified in the Synapse report in Attachment A, do complement the monthly capacity factors of solar and wind resources to some degree; however, a physical balance is not required to be maintained by individual utilities. ISO-NE ensures that there is sufficient generation on-line at any given time to match load requirements, and can balance intermittent generation across the New England area. This provides significantly more flexibility and allows for greater amounts of intermittent generation at the regional level. Further, absent cost-effective storage, dispatchable generation is still required to fully balance the intermittent nature of the three resource types to ensure that load is served.

B. Environmental Policy

On May 4, 2016, the Agency of Natural Resources issued a memorandum that provides an overview of the FERC relicensing process.[29] The memorandum is included as Attachment B of this Report. This section of the report offers a brief summary of environmental policy considerations in order to provide context for analyzing potential policy conflicts related to dam acquisition.

Environmental Assessment

Under the Federal Power Act, FERC is responsible for ensuring that FERC-jurisdictional dams comply with the National Environmental Policy Act's environmental assessment process. FERC has adopted agency-specific procedures for implementing NEPA.[30] When FERC issues a final environmental assessment for a project, it must give "equal consideration" to developmental and non-developmental (or environmental) values under Section 4(e) of the Federal Power Act. The "equal consideration" analysis requires FERC to balance developmental

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[27] Vermont Comprehensive Energy Plan 2016 at 383.
[28] CEP at 261.
[29] Hydroelectric dams that do not fall under FERC jurisdiction typically fall under the jurisdiction of the PSB. The review of PSB-jurisdictional facilities is governed by 10 V.S.A. § 1086, which requires a determination that a facility is in the "public good." This review requires a consideration of many factors, including environmental and agricultural impacts as well as state, regional, and municipal planning issues. The TransCanada dams are regulated by FERC and therefore this report focuses on the FERC process and environmental review.
[30] 18 C.F.R. § 380 et seq.

and environmental values. Developmental values include: utilization of the site's hydroelectric potential; potential benefits to interstate or foreign commerce; flood control; and water supply.[31] Environmental values include: adequate protection, mitigation, and enhancement of fish and wildlife (including their spawning grounds and habitat); recreational opportunities, visual and cultural resources, and other aspects of environmental quality.[32] In addition, Section 10(a) of the FPA requires that FERC consider resource agency recommendations for ensuring that a project is best adapted to comprehensive plans for developmental and non-developmental resources and Section 10(j) of the FPA requires that FERC consider resource agency recommendations to protect, mitigate damages to, and enhance fish and wildlife resources under FPA Section 10(j).

Water Quality

Before FERC can issue a license to construct or operate FERC-jurisdictional dams, section 401 of the Clean Water Act requires that the host states have either issued a water quality certification for the project or waived certification by failing to act on a request for a certification within a reasonable period of time, not to exceed one year.[33] Unlike the FERC environmental assessment "equal consideration" analysis, a certifying state may not assess developmental values in its analysis. A state's 401 certification shall include a statement from the state that "there is a reasonable assurance that the activity will be conducted in a manner which will not violate applicable water quality standards."[34] As a result, state-issued water quality certifications may include conditions to ensure that the operation of the dams do not violate Vermont's water quality standards.[35] FERC is required to incorporate these conditions into the license issued to the owner of the dam.[36]

Currently, the Wilder, Bellows Falls, and Vernon stations are in the middle of the relicensing process, with the licenses expected to be issued in 2019. Vermont and New Hampshire, along with federal resource agencies, are working with TransCanada to ensure that the appropriate studies are conducted to inform the conditions to be imposed as part of the relicensing process. The Agency of Natural Resources' memorandum provides a conservative estimate of the potential impact of the conditions that are likely to be imposed on the three facilities – potentially a 30% reduction in revenues from the dams currently up for relicensing. This estimate is based on the outcomes of the relicensing process at other dams in Vermont as the necessary studies have not been completed to provide more than a high-level conservative estimate for the three TransCanada dams. Each river and associated dams have different characteristics that determine operating conditions and several studies have yet to be completed.

[31] Federal Energy Regulatory Commission, *Handbook for Hydroelectric Project Licensing and 5 MW Exemptions from Licensing*, at Section 1.2 (2004), *available at* http://www.ferc.gov/industries/hydropower/gen-info/handbooks/licensing_handbook.pdf (last visited July 29, 2016).
[32] *Id*.
[33] 33 U.S.C. § 1341(a)(1).
[34] 40 C.F.R. § 121.2(a)(3).
[35] 33 U.S.C. § 1341(d)
[36] *Id*.

Consequently, the final impact on dam operations, and consequently revenues, will not be fully known for some time.

The TransCanada dams on the upper Connecticut River, known as the 15-Mile Falls project, and the dams on the Deerfield River will have to undergo the relicensing process in 2042 and 2037, respectively. These projects will be subject to the current water quality standards which generally reduce the ability to store and drawdown water and also increase conservation water flows; effectively the existing water quality standards are likely to make the projects more similar to run-of-river projects. The impact is to reduce the ability to manage the timing of generation, and thereby reduce the energy and capacity revenues that the dams receive.

Lands Associated with the Dam Facilities

There are almost 30,000 acres of land associated with the TransCanada dam facilities. In the 1997 relicensing of the Deerfield River project, the final license included a settlement in which 18,350 acres of land was protected from development through permanent conservation easements. The Vermont Land Trust holds the easement on the 15,736 acres within Vermont, with the Massachusetts Department of Conservation and Recreation holding the easement on lands within Massachusetts. The easements in Vermont are in the towns of: Reasdboro, Searsburg, Whitingham, Wilmington, Somerset, and Stratton. There is an additional 1,252 acres of land associated with the Deerfield River project that are not subject to easements, however, it is not clear where these lands are located.

Lands associated with the 15-Mile Falls projects include 3,965 acres in the towns of Barnett, Waterford, Concord, and Lunenburg. There are an additional 2,953 acres of land held in easement in New Hampshire. The easements are held by the New England Forestry Foundation. There is also 1,282 acres of land that is not subject to easement, however, it is unclear where these lands are located.

Staff were unable to locate publically available information for the Wilder, Bellows Falls, and Vernon facilities. To the extent that a purchase option is pursued, such information should be available from the owner during negotiations.

Carbon Reduction Goals

In 2005, the State established the following greenhouse gas reduction goals:

> It is the goal of the state to reduce emissions of greenhouse gases from within the geographical boundaries of the state and those emissions outside the boundaries of the state that are caused by the use of energy in Vermont in order to make an appropriate contribution to achieving the regional goals of reducing emissions of greenhouse gases from the 1990 baseline by:
> (1) 25 percent by January 1, 2012;
> (2) 50 percent by January 1, 2028;

> (3) if practicable using reasonable efforts, 75 percent by January 1, 2050.[37]

In addition the Vermont CEP establishes a goal of meeting 90% of the State's total energy needs from renewable resources by 2050.

As noted earlier in this report, the owner of the dam facilities will likely want to maximize the production of renewable energy in order to maximize revenues. This profit motive is well aligned with the carbon reduction goals listed above as the renewable generation from the dams will displace generation from fossil-fuel-fired resources and therefore lower carbon emissions. To the extent that the State or Vermont utilities acquire or enter into contracts with the new owners for the output, these reductions can be counted toward these goals. As noted elsewhere, ownership or a PPA with a renewable resources anywhere capable of delivering renewable energy into New England would also could toward this goal.

C. Economic Development

Potential impact of sale on municipalities (taxes, services, etc.)

While ownership by private entities such as a merchant generating plant or a Vermont utility would not change the tax structure, ownership of the assets by the State would mean that the property would not be subject to taxes, but the state would be required to provide payments in lieu of taxes.[38] It's unlikely that State ownership would alter the number of employees currently needed to operate and maintain the facilities.

As noted above, the TransCanada hydroelectric facilities include almost 30,000 acres of land. Currently, these lands are subject to some restrictions and requirements related to recreational access as a result of the FERC hydroelectric license requirements. In theory there may be an opportunity to achieve additional value from the land through such activities as timber harvests or leases for solar facilities; however, these activities would be limited by the conservation easements in place on the majority of the land. Even if the State owned the lands and wished to increase utilization of the land, the third parties that own the easements would still limit such activities. Additionally, if there is untapped economic potential associated with the 30,000 acres, it's unclear why the current owner would not have taken advantage of these opportunities. Finally, State ownership could provide the opportunity to increase recreational opportunities associated with the land; however, any costs associated with such recreational improvements would need to be accounted for in the economics of any purchase of the facility.

The lands and waters associated with the facilities, especially the extensive contiguous holdings along the Deerfield, may present recreation, forestry, and other economic and social benefits to the host towns and the State as a whole. We suggest the State allocate funding and convene a collaborative effort of affected regional planning commissions, municipalities, and relevant state agencies to: (a) identify the role of the holdings in the life, economy, and fiscal

[37] 10 V.S.A. § 578(a).
[38] *See* 30 V.S.A. § 5015(c).

well-being of the towns (individually and collectively); (b) identify how the resources might be more effectively managed; and (c) develop a comprehensive management plan for areas of contiguous holdings.

Using assets to drive economic development through rates

There is an important distinction between a potential Vermont ownership of the dam facilities and public power projects such as the New York Power Authority, the Tennessee Valley Authority, and the Bonneville Power Administration. The latter projects were largely constructed using federal money, thereby providing significant subsidies to the states hosting these projects, as well as neighboring states.[39] TransCanada is selling the dam facilities at market value; accordingly, any purchase of the facilities will not produce the subsidized power rates that have facilitated economic development in the regions noted above.

In theory, public ownership should decrease the cost of power, as a public owner would not need the same return on equity that a private owner would expect. Even to the extent that public ownership would result in lower rates than private ownership, the cost of the output from the facilities is still primarily dependent on operation and maintenance cost, and these costs vary according to individual generation resources. Accordingly, the cost of output from a publically owned renewable generation resource could still be more expensive than a privately owned renewable generation resource that has lower operation and maintenance costs.[40]

Over the long-term, regardless of whether the dam facilities are owned by a governmental or private entity, once the costs of the purchase have been paid off, ownership of the dams could facilitate the provision of inexpensive power.

As noted above, State ownership itself would likely not result in significantly less expensive production costs; however, after the acquisition costs are paid off, the costs would be limited to operations and maintenance and could result in less expensive power (assuming that O&M costs do not increase significantly with the age of the infrastructure). At that point, there may be an opportunity for less expensive power that could be provided to the benefit of Vermonters. This could be accomplished through selling the power at cost to Vermont utilities for the benefit of all ratepayers, or the power could be sold by the State directly to specific categories of retail customers in order to provide lower power costs for specific commercial and industrial users.[41]

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[39] Vermont receives a portion of New York Power Authority energy and capacity because the FERC licenses for the Niagara and St. Lawrence projects require that the potential benefits be shared with neighboring states.
[40] For fossil fuel fired or biomass resources, the cost of the output is also highly dependent on the cost of fuel. In the case of hydroelectric, wind, and solar resources operations and maintenance are the primary costs.
[41] *See* 30 V.S.A. § 212a.

In January 2016, the DPS produced a report to the legislature regarding electric rates targeted for economic development.[42] The report concludes

> At this time, specific recommendations for modifying the structure of electric rates in Vermont would be premature. However, a longer-term review of the rate structure is critical. ACCD [Agency of Commerce and Community Development], PSD, and manufacturing businesses need to engage in joint discussions to ensure a common understanding of how rate structure changes will allow for the most cost-effective future delivery of electricity services.[43]

Further exploration of this issue would be warranted if the State were to acquire the dam facilities. To the extent that the State or Vermont utilities enter into a PPA with the eventual owner, it's unlikely that owner would offer rates sufficiently low as to provide preferential rates to specific categories of customers.

POTENTIAL POLICY CONFLICTS AMONG ENERGY, ENVIRONMENTAL, AND ECONOMIC DEVELOPMENT GOALS

The opportunity to purchase the output of the dams, even without an ownership option, provides the state of Vermont with a means to ensure that the numerous benefits associated with the continued operation of the hydroelectric facilities are maintained. As discussed in Section IV above, the continued operation of the Connecticut and Deerfield river hydro systems will ensure a relatively low-cost, zero-carbon resource remains part of the region's energy supply mix. If the State were to own or contract for the energy output of the facilities, it will ensure that these resources contribute to Vermont's goal of becoming 75 percent renewable by 2032. However, as outlined in Section V above, there are several other regulatory constraints and policy considerations that limit the ability of these hydro resources to achieve maximum energy output for economic and RES purposes. The entities involved in implementing these regulations and making these policy decisions may include agencies from adjacent states (NH and MA), the Federal Energy Regulatory Commission, U.S. Fish and Wildlife Service, National Oceanic and Atmospheric Administration's National Marine Fisheries Service, U.S. Environmental Protection Agency, as well as special interest groups at both a state and national level.

A. ENVIRONMENTAL ASSESSMENTS AND THE RES

As discussed in Sections IV and V, the relicensing process for several of these facilities may require operational changes in order to support multiple uses of the waterways pursuant to the FERC environmental assessment and the Vermont Water Quality Standards. This could

[42] *Act 199 study on manufacturing competitiveness and energy*, January 22, 2016, available at http://legislature.vermont.gov/assets/Legislative-Reports/Act-199-Report-FINAL.pdf.
[43] Act 199 Report at 15.

include increasing water flows and restricting operation during certain times of year in order to preserve water quality, river flows, and species habitat. Such changes would impact the economic value of the facilities by restricting the maximum output (and therefore RECs) as well as the timing of the hydro generation to times that may not coincide with maximum energy market prices. As a result, the ability to achieve Vermont's goal to maximize renewable energy is bound by the regulatory constraints with which FERC, the PSB, and the resource agencies are mandated to implement.

The VWQS also require that rivers be maintained to support aesthetics and recreational uses, such as fishing, swimming, and boating. These uses are typically protected and maintained with the same increased water flows and operation restrictions put in place to protect water quality and aquatic habitats; however, there can be additional conditions included with Water Quality certifications that could impact the hydro facilities' ability to maximize their renewable energy output and economic value.

B. VWQS VERSUS HYDRO AS A BALANCING RESOURCE FOR INCREASED INTERMITTENT RESOURCES

Currently, hydro resources are valuable as a reliable, readily-available source of renewable energy that can be counted on most times of the year to provide electricity. This helps to back up more intermittent resources like wind and solar that are available only when the wind is blowing or the sun is shining. However, in the coming years, as more and more variable energy resources are added to the grid, there is likely to be a price premium for very flexible resources that can come on or go off the grid on short notice. Hydro resources like these can provide that type of flexible operation and would earn premium prices for that service. However seasonal and other operational restrictions due to water quality and recreational concerns could reduce the flexibility of these resources and deny them some of those opportunities to earn premium prices.

C. ECONOMIC DEVELOPMENT POTENTIAL

Vermont hydro ownership or a State PPA for the hydro output can provide an economic benefit to the state in several ways. First, there is the retention of the jobs associated with the management and operation of the hydro facilities. Second, the contributions to local property taxes from the hydro facilities will continue to offset the need to collect taxes from other real estate in the town. Third, the long-term stability of hydro costs will help provide stability to Vermont electric rates, whether the hydro facilities are owned by the state or whether the hydro output is captured in a long-term PPA.

For Vermont the goal will be to find a balanced approach to addressing all these competing policy goals. Ownership may provide the most effective way to control the decisions and achieve a balanced outcome. However, even in the absence of an ownership interest, the state can negotiate a purchase power agreement that recognizes the various options for addressing policy issues and describes a process for resolving any disputes that may arise. Vermont may be able to learn from other regions of the United States that have dealt with these issues, such as the Bonneville Power Authority and surrounding states in the Pacific northwest. It would be important that a clear process and priorities be established prior to any acquisition of the dam facilities.

RECOMMENDATION REGARDING THE PURCHASE OF THE DAM FACILITIES

A. IS IT REASONABLE FOR THE STATE OF VERMONT TO PURCHASE THE DAM FACILITIES?

The purchase of the facilities by the State could provide a long-term benefit, but it is not without risk. Further, the decision to put hundreds of millions of dollars of Vermonters' money at risk is one that should only be made after a full, transparent discussion with significant opportunity for the public to weigh in.

The benefits of acquiring an interest is the long-term ownership of a group of resources that provides renewable power that could continue to provide value long after the purchase costs have been fully recovered. The risks include unforeseen premature retirement of some of the facilities, significantly less rainfall as a result of climate change, and even changes in generation technology forty years from now that make the dam facilities obsolete.

B. FEASIBILITY OF ACQUIRING THE DAM FACILITIES FROM TRANSCANADA

Given the deadlines for the sale, the significant interest from other hydro owners, and the expense and time required to perform the necessary due diligence, the State was not able to put together a legitimate bid within the time frame necessary.

The timing associated with TransCanada's sale process is reasonable for large companies with acquisition experience. Within the past few years, two companies, each backed by billions of dollars of pension funds, have completed acquisitions of significant groups of hydroelectric assets. Most recently, H2O Power acquired 1.2 GW of hydro assets from Engie for over $1 billion, while Brookfield Renewable Energy Partners acquired hydroelectric facilities totaling 270 MW of nameplate capacity in Maine from NextEra Energy Resources and Black Bear Hydro Partners in 2012 and 2013. In contrast, the State has no experience with acquiring any generation assets and would need significant assistance from outside experts in order to acquire the hydroelectric assets.

In addition, there are significant costs associated with any potential acquisition. Act 130 appropriated $75,000 for this study, and allows an additional $175,000, provided that the Secretary of Administration make an offsetting reduction from elsewhere in the State's 2017 budget. The total potential study amount of $250,000 is a significant amount when considered in the context of the Vermont government's 2017 budget. However, that amount is only 0.025% of the total estimated $1,000,000,000 value of the hydroelectric assets under study. Although the $250,000 set forth in Act 130 relates to a study and the ability to preserve options, given the timing of the sale it effectively caps the total amount that could be spent to perform the necessary due diligence (including highly technical review of TransCanada's financial, engineering, and operations information), form the hydroelectric authority or a partnership, and negotiate with a multibillion dollar company on the terms of the acquisition. For a simple point of comparison, this would be equivalent to spending no more than $50 for the purchase of a $200,000 house (including home inspection, title search, appraisal, and closing costs). Further, the State could decide to commit the necessary expenditures to submit a legitimate bid and still lose out in the sale process.

C. Feasibility of Acquiring an Interest in the Dam Facilities in the Future

As noted above, any entity that acquires the dam facilities would likely have an interest in entering into a power purchase agreement with the State or Vermont utilities for the purchase of the output of the facilities. A PPA, in itself, is a long-term interest in the output of the dam facilities, although it provides no means of control of the facilities or the associated lands. A PPA could also include a provision that allows for the eventual purchase of some equity interest in the facilities at some point in the future, thereby providing further opportunity for public discussion of whether it is reasonable for the State to expend hundreds of millions of dollars to acquire an interest in the facilities.

It is important to note that the price will determine whether a PPA is beneficial to Vermont; to the extent that the state or individual utilities are not able to negotiate a reasonable price, on balance a PPA would not provide a benefit.

D. Overall Recommendation

The Working Group recommends that the Department of Public Service approach the eventual owner of the dam facilities to ascertain interest in a long-term PPA with the inclusion of a provision for purchase of all or some equity stake in the dam facilities. This option would not lock in the State into purchasing the dam facilities but would instead provide time for sufficient public input into such a purchase and a more complete analysis. In making this recommendation, the Working Group is aware that the resources necessary to make such a purchase would be significant. Further, any PPA would need to clearly provide a benefit to Vermont ratepayers and would need to be pursued in consultation with the State's electric distribution utilities to ensure that such a commitment matches the power supply needs of the utilities.

APPENDIX A – REPORT OF SYNAPSE ENERGY ECONOMICS ON THE ECONOMIC VALUE OF THE DAM FACILITIES

Preliminary Valuation of TransCanada's Hydroelectric Assets

Prepared for the State of Vermont

August 1, 2016

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1. INTRODUCTION

TransCanada is looking to sell its Northeast generation assets in order to finance the purchase of the Columbia Pipeline Group. These assets are: 16 dams, three gas plants, a wind facility, and a power marketing company. TransCanada has indicated that it is willing to sell the hydro assets as a bundle, but not individually. As a publicly traded corporation, TransCanada is obligated to conduct an open solicitation process. On May 26, 2016, JP Morgan, the agent for this sale, sent a description of the assets for sale and details of the bidding process to interested parties. The state of Vermont, through the Vermont Hydroelectric Power Authority, is considering the possibility of acquiring the hydro assets shown on the map below. Even if it does not move forward with a bid, the State has an interest in the outcome of this process and may want to enter into purchased power agreements (PPA) for the output of the hydro facilities to help meet state energy goals.[1]

Figure 1. Map of TransCanada's Connecticut and Deerfield River Hydro Facilities

Source: TransCanada. 2012. Factsheet on Connecticut River and Deerfield River Hydro Facilities – June 2012.

[1] Memorandum from Ed McNamara, Regional Policy Director, DPS to Justin Johnson, Secretary of Administration and Christopher Recchia, Commissioner of Public Service, June 6, 2016.

Synapse Energy Economics was engaged by the State of Vermont to provide an estimate of the current value of the TransCanada hydroelectric facilities on the Connecticut and Deerfield Rivers to better understand the available options. This report provides a preliminary estimate of the value of the 14 TransCanada hydropower facilities being offered for sale along the Connecticut and Deerfield rivers, shown on the map above.

For this analysis, Synapse relied primarily on the detailed and exhaustive plant valuation studies carried out by G. E. Sansoucy in 2010 and 2013. We then made appropriate adjustments to reflect changed market expectations since those studies were carried out. It is important to note that this is only a preliminary assessment; a comprehensive valuation of the TransCanada Connecticut and Deerfield rivers hydro facilities would require much more detailed information and time than was available for this study. The available time is limited by the relatively rapid pace of the sale process, and data access is limited by the existing disclosure process. Bidders are able to access additional proprietary information by signing a non-disclosure agreement; neither the State of Vermont nor Synapse have signed this agreement.

The costs of hydro facilities are fairly stable and predictable. They also tend to be fixed and independent of the amount of actual generation, which can vary greatly from year to year and even from month to month depending on rainfall and river flow. Economic analyses of hydro facilities generally use historical annual averages to estimate generation; however, the effects of climate change—as well as increased operational restrictions to protect water quality, wildlife, and recreational uses—make it more challenging to predict future annual averages. This leads to significant uncertainty on the revenue side.

Most of the revenue for these hydro facilities comes from the New England electric energy and capacity markets. Overall, energy market payments account for about four-fifths of hydro plant revenue and capacity payments account for most of the rest.[2] In New England, seasonal energy prices and annual capacity market prices have been volatile in recent years. Forecasts of future energy or capacity prices remain uncertain, although the persistence of low-priced natural gas suggests low electricity prices for daily energy needs. Also, as previously noted, the amount of energy generated by these facilities is variable, which compounds the uncertainty with respect to energy revenue. Another key consideration in our assessment of revenue was the uncertainty created by the current re-licensing of the three Lower Connecticut River facilities. Relicensing raises new uncertainties about the operation and, ultimately, the revenue value of both the energy and capacity ratings for the future operation of those three facilities. Although the three Lower Connecticut River facilities do not have a large impact on the overall valuation of the TransCanada portfolio of dams and reservoirs, the potential revenue changes for those three facilities could be significant.

[2] Some hydro facilities also earn some revenue in the ancillary and reserve markets, but generally those earnings are quite small.

For the TransCanada hydro facilities on the Connecticut River, we calculate a reasonable current valuation to be in the range of $791 to $1,146 million, compared to the 2012 Sansoucy valuation of $888 million (inflated to 2016$).

For the TransCanada hydro facilities on the Deerfield River (including those in Massachusetts) we calculate a reasonable current valuation to be in the range of $184 to $230 million, compared to the 2010 Sansoucy valuation of $205 million (inflated to 2016$ and scaled up to include dams in Massachusetts).

Table 1. Previous Sansoucy Variations and Synapse Current Estimate of Valuation Ranges

				Range of Possible Valuations (M$)	
Hydro Facilities	**Capacity (MW)**	**Generation (MWh)**	**Sansoucy Valuation (M$)**	**Low**	**High**
Connecticut River	484	1,237,200	$888	$791	$1,127
Deerfield Total	84	286,950	$205	$190	$238
CT & Deerfield Total	**553.5**	**1,524,150**	**$1,092**	**$981**	**$1,364**

Note: All valuations in 2016 dollars.

2. Historical Valuations

2.1. Sansoucy 2010 and 2013 Appraisals

In April of 2013, G. E. Sansoucy completed an appraisal report of the hydroelectric properties owned by TransCanada on the Connecticut River in New Hampshire and Vermont.[3] The table below shows those valuations as of April 2012. Not included in this list are the First and Second Connecticut Lake dams in the river's headwaters that provide storage but no electrical generation. The total valuation of the facilities included in this report is $820 million (in 2012$ or $888 million in 2016 dollars). The total capacity of these facilities is 484 MW.[4]

[3] George E. Sansoucy, PE, LLC. 2013. *Self-Contained Appraisal Report of the Hydroelectric Properties Owned By TransCanada Hydro Northeast, Inc. on the Connecticut River in the State of Vermont*. Volume I. Prepared for the State of Vermont.

[4] Based on 2016 ISO-New England summer capacity rating. Available here: http://www.iso-ne.com/system-planning/system-plans-studies/celt/?document-type=CELT%20Reports.

Table 2. Sansoucy Connecticut River Valuations 3

	A	B	C
Row#	Facility	Total Reconciled Value All Improvements and Land and Land Rights	Value of All Improvements and Land and Land Rights in Vermont
1	Moore Development	$210,000,000	$38,051,900
2	Comerford Development	$238,000,000	$45,143,200
3	McIndoes Development	$25,000,000	$3,916,500
4	Wilder Project	$92,000,000	$40,809,100
5	Bellows Falls Project	$130,000,000	$109,853,600
6	Vernon Project	$125,000,000	$39,775,200
7	**Totals**	$820,000,000	$277,549,500

Source: G.E. Sansoucy 2013 appraisal report of the hydroelectric properties owned by TransCanada on the Connecticut River in New Hampshire and Vermont.

In July of 2010, G. E. Sansoucy completed an appraisal report of the hydroelectric properties owned by TransCanada on the Deerfield River in Vermont.[5] The table below shows those valuations as of April 2010. [6] Note that this evaluation includes Somerset, which is a storage-only facility. It includes only the two Deerfield hydro plants that are in Vermont—Searsburg and Harriman—which represent 45 MW of the 84 MW capacity that exists on the Deerfield River (the other four facilities are located in Massachusetts). The total valuation of the Vermont facilities included in the Sansoucy report is $86.75 million (in 2010$). Based solely on the capacity values and using Sansoucy's estimates, the full value of the Deerfield system in both Vermont and Massachusetts would be about $182 million (in 2010$ or $205 million in 2016$).[7]

[5] George E. Sansoucy, PE, LLC. 2010. *Self-Contained Appraisal Report of the Hydroelectric Properties Owned By Transcanada Hydro Northeast, Inc. on the Deerfield River in the State of Vermont*. Volume II. Prepared for the State of Vermont.

[6] Ibid, page 82.

[7] Sancoucy's 2010 Deerfield estimate was $86.75 million for plants which represent 43 percent of the Deerfield generation. We use that factor to scale up the estimate for the entire system. That is then inflated at 2 percent per year to get the value in 2016$.

Table 3. Sansoucy Deerfield River Valuations

Row #	A	B
	Facility	Total Reconciled Value
1	Somerset	$14,000,000
2	Searsburg	$9,750,000
3	Harriman	$63,000,000
4	Total	$86,750,000

Source: G.E. Sansoucy 2010 appraisal report of the hydroelectric properties owned by TransCanada on the Deerfield River in the State Vermont; summary of reconciled values as of April 1, 2010.

2.2. Previous Synapse Valuations

From 2000 through 2008, Synapse carried out a number of tax valuations of hydro facilities in Vermont. The most comprehensive study was released in April 2000[8] and looked at the same facilities as in the more recent Sansoucy reports. In those studies, we carried out detailed income and expense calculations similar to those used in the Sansoucy valuations. For these studies we had access to and evaluated detailed hydrologic and operational data. The summary of our 2000 valuation study for both river systems is shown in the table below (in 2000$).[9]

[8] Synapse Energy Economics, Martin Appraisal Services, and Resource Insight. 2000. *Valuation of Hydroelectric Generating Facilities on the Connecticut and Deerfield Rivers in Vermont.* Prepared for Vermont Department of Taxes. Available at: https://www.scribd.com/document/219885355/SynapseReport-2000-04-VT-Dept-of-Taxation-valuation-of-Hydroelectric-Facilities-in-VT-00-13-Technical-Report.

[9] Ibid, page 2.

Table 4. Synapse Connecticut and Deerfield River Valuations (2000$)

Summary of USGen New England, Inc. (PG&E) Connecticut and Deerfield River Hydropower Facilities Market Valuations ($ 000's)		
Station	**Income Approach**	**Replacement Cost**
Moore	$226,979	$211,737
Comerford	$160,471	$152,803
McIndoes	$14,639	$15,351
Wilder	$50,571	$48,966
Bellows Falls	$75,246	$76,273
Vernon	$28,088	$26,560
Total Connecticut River:	**$555,994**	**$531,690**
Somerset	$916	$869
Searsburg	$5,361	$5,082
Harriman	$59,496	$55,266
Total Deerfield River:	**$65,773**	**$61,217**
Total Value:	**$621,767**	**$592,907**

Source: Synapse Energy Economics 2000 study of Connecticut and Deerfield River valuations.

Although these valuations are based on dated information, they rely on extensive knowledge of these hydro facilities and provide a rough benchmark for the later studies. For instance, Sansoucy's estimate of the CT River dams' value for 2012 ($820 million in 2012$) was 47 percent higher than Synapse's valuation for 2000 ($556 million in 2000$). After accounting for inflation, this represents a 1.05 percent annual increase in value.[10] This increased value was driven by a variety of factors including concern about greenhouse gases and low interest rates (among others). However, we do not explore those factors in-depth in this report.

[10] The average annual growth in value for the CT River plants was 3.3 percent from 2000 to 2012. General GDP price inflation over the same period (2000 to 2012) was 30 percent, or 2.2 percent per annum. Thus after inflation, the average annual growth in "real" value of the facilities was 1.05 percent.

3. KEY VALUE DRIVERS

3.1. Overview

The key to valuing hydro generation facilities is anticipating the net revenue stream over the anticipated plant lifetime.

Hydro facilities' costs tend to be stable and predictable. First, there are no fuel costs, which is an important and sometimes volatile factor for conventional combustion generators. Second, the ongoing or periodic maintenance and replacement costs are well-known and the equipment is long-lived. In recent years, advances in automation have reduced the requirements for operational personnel, thus lowering those costs. But overall, costs are stable and fixed, with little dependence on the actual generation.

Revenues, on the other hand, can be less predictable. Most hydro plant revenues come from electric energy sales and from capacity payments. The energy revenues depend on generation, and are determined by the actual river flow, the timing of the generation, and market prices. Hydro facilities can sell energy into the daily market, which can be quite variable, or enter into long-term contracts for a fixed price. These contracts, although stable, depend on price expectations at the time they are negotiated.

For hydro plants in New England, the net revenue margin is generally quite robust, with gross revenues exceeding plant costs (excluding capital costs) by a factor of three or more. Thus they represent very low risk investments from a purely market-based perspective. Even with some of these facilities at nearly a century old, the risk remains low. Civil engineering structures such as these can last for centuries if properly maintained, and the mechanical equipment can be replaced and upgraded as needed.

However, the biggest operational variable for these facilities, besides the actual availability of water due to weather, is the impact of increasingly stringent water quality standards. When hydro facilities are relicensed—a process that occurs approximately every 40 years—they must come into compliance with modern environmental standards. These include standards that protect water quality and aquatic species, and often require significant restrictions on water levels, water flows, and timing of operation for dams. Such restrictions can have a direct impact on generation and, therefore, can affect revenues.

3.2. Plant Characteristics

Altogether there are eight facilities on the Connecticut River and eight on the Deerfield.

Two of the Connecticut facilities are storage-only and six are generating stations, designed with a total nameplate capacity of 495 MW. Note that the nameplate rating is different from the current ISO-NE CELT capacity rating (484 MW) and that used in Sansoucy's 2013 appraisal (496 MW) (see Section 2.1).[11] The two Upper generators (Moore and Comerford) are the largest, representing 73 percent of the total capacity (MW) and averaging 52 percent of the total generation (MWh). Overall, the 15-year weighted average capacity factor for all six dams is 30 percent. This reflects seasonal variations in river flow and facility sizing to allow timing of generation to get the best prices.

On the Deerfield River, there are seven generating facilities and one storage-only facility (Somerset) totaling 86 MW of nameplate capacity. Harriman station is the largest generator, representing 49 percent of the capacity and 37 percent of the generation. The 15-year weighted average capacity factor is a little higher than those on the Connecticut River at 39 percent. The table below provides an overview of the hydro facilities on the Connecticut and Deerfield Rivers. [12,13]

[11] There are many factors evaluated to determine the capacity value of a hydro resource. They include overall historical data and specific seasonal data, as well as operating characteristics. For capacity values, we use those from the ISO-NE May 1, 2016 CELT Report unless otherwise indicated.

[12] Average generation is based on EIA data 923 data for 2001-2014 (excluding anomalous values from 2007). ISO-NE CELT capacity values are based on actual generation and may differ from nameplate ratings for a variety of reasons. The CELT values reflect what is eligible to participate in the forward capacity market.

[13] In this table we use the latest ISO-NE capacity values from CELT 2016. These differ slightly from values in previous CELT reports and in the Sansoucy valuations.

Table 5. Connecticut and Deerfield River Hydro Facilities

Facility	In Service Date	Nameplate Capacity (MW)	ISO-NE CELT Capacity (MW)	Generation (avg. annual MWh)	Capacity Factor	Location
Connecticut River Facilities						
Second Connecticut Lake Dam	1914	Storage only				
First Connecticut Lake Dam	1915	Storage only				
Moore Development	1957	192	189	291,753	17.6%	Littleton, NH; Waterford, VT
Comerford Development	1930	167	166	349,717	24.0%	Monroe, NH; Barnet, VT
McIndoes Development	1931	11	10	48,504	54.4%	Monroe, NH; Barnet, VT
Wilder Station	1950	41	39	157,792	46.1%	Hartford, VT; Lebanon, NH
Bellows Falls Station	1928	48	47	245,734	59.4%	Rockingham, VT; Walpole, NH
Vernon Station	1904	36	32	143,699	51.3%	Vernon, VT; Hinsdale, NH
Connecticut Total		**495**	**484**	**1,237,200**	**29.2%**	
Deerfield River Facilities						
Somerset Dam	1911	Storage only				Somerset, VT
Searsburg Station	1925	5	4	17,755	45.5%	Searsburg, VT
Harriman Station	1925	41	41	106,665	29.7%	Readsboro & Whittington VT
Sherman Station	1927	6	6	30,511	56.6%	Rowe & Monroe MA
Deerfield #5	1974	14	14	55,079	45.0%	Rowe & Florida MA
Deerfield #4	1913	6	6	23,529	48.0%	Buckland & Shelburne MA
Deerfield #3	1913	7	6	25,875	45.5%	Buckland & Shelburne MA
Deerfield #2	1913	7	6	27,537	48.4%	Conway & Shelburne MA
Deerfield Total		**86**	**84**	**286,950**	**39.0%**	

Source: TransCanada, ISO-NE, and EIA.

Although these facilities are generally identified as peaking units, the annual capacity factors are more typical of intermediate units. Thus they actually represent a change in operational mode from month to month depending on the river flow. ISO-NE characterizes these facilities as "Daily Cycle – Pondage" or "Weekly Cycle," which indicates a certain level of short-term flexibility.[14]

The storage reservoirs can provide an adequate to moderate river flow on a daily to weekly basis, but not enough to achieve seasonal shifts such as storing all the spring flows to use in the summer. This is illustrated in the next figures, which show the average monthly capacity factors for these facilities based on data from 2000 through 2014.[15] The March peak represents the spring runoff, when there is so much water that it has to be used to generate electricity or else spilled over the dam. The April valley represents a time when the reservoirs are being refilled. And finally, the May-June peak represents both higher river flows and a drawdown of reservoir storage during times of higher electricity need. High capacity factors (over 80 percent) indicate baseload operation while low capacity factors (less than 20 percent) indicate that the plants are running in a peaking mode.

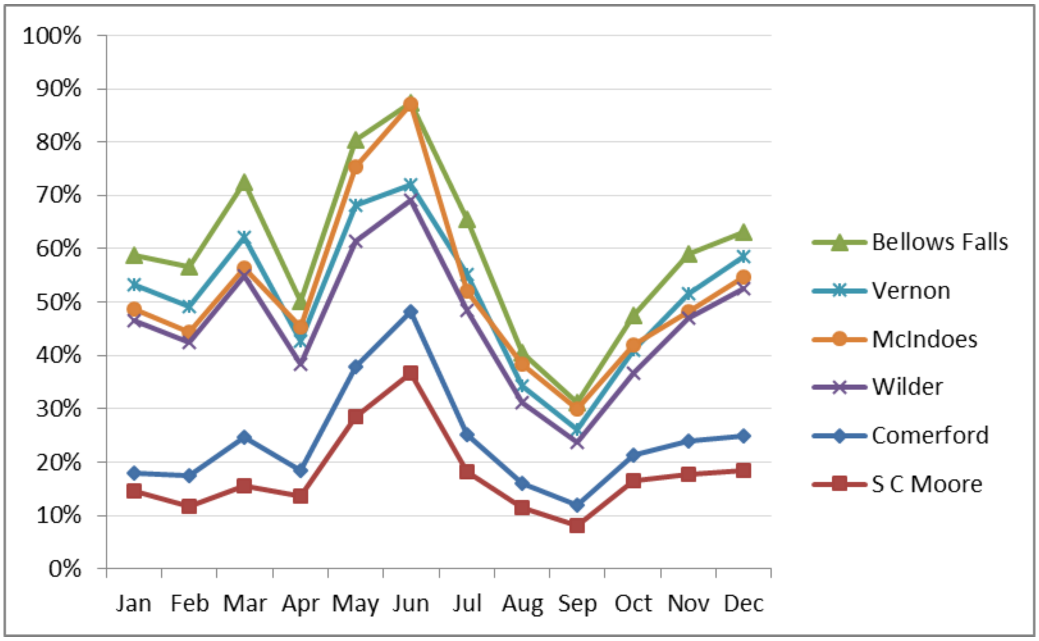
Managing a hydroelectric river system to meet environmental and operational requirements, while maximizing revenue, is a complicated process. By July through September, river flows are generally lower and storage is being used to time the daily generation schedule to get the highest prices. But

[14] ISO-NE 2016 CELT Report "Generator List."

[15] EIA 923 data.

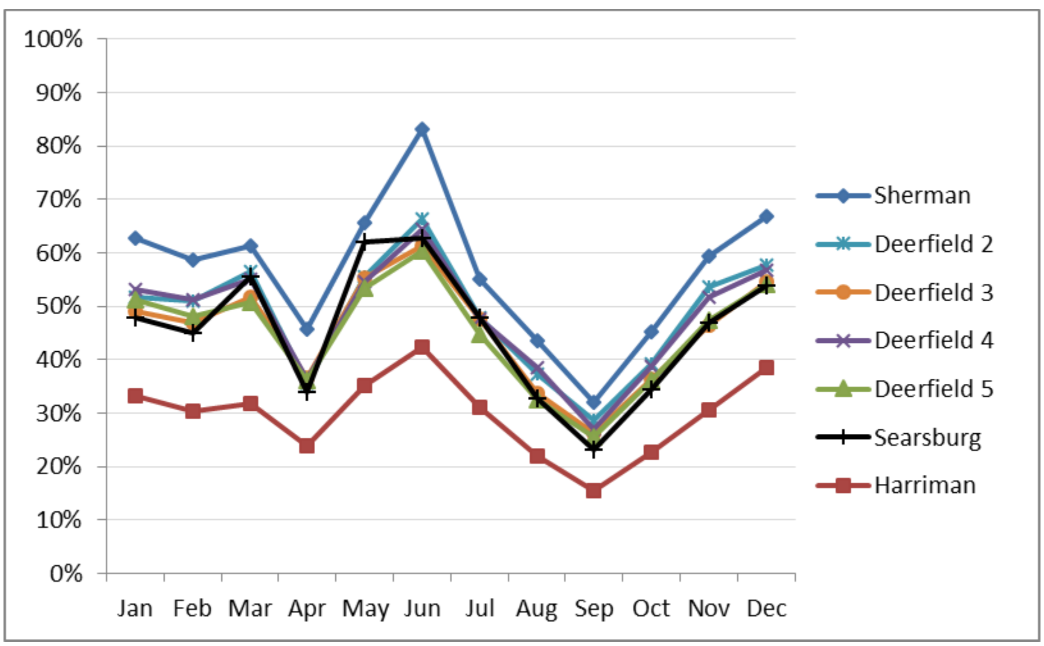
summer also brings minimum flow requirements, which keep many of the plants running at lower levels in all hours.

Figure 2. Connecticut Facility Capacity Factors – Monthly Average (2001-2014)



Source: Synapse Energy Economics, 2016.

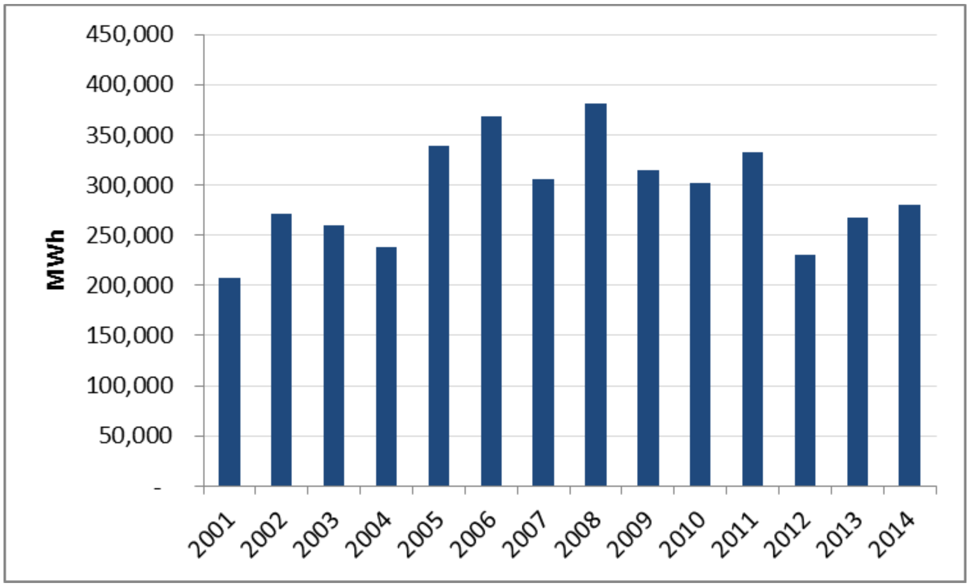
Figure 3. Deerfield Facility Capacity Factors – Monthly Average (2001-2014)



Source: Synapse Energy Economics, 2016.

Generation can also vary substantially from year to year, as illustrated by the following chart for the Moore facility. This chart shows that the variation from one year to the next can easily be 20 percent or more.

Figure 4. Moore Facility Annual Generation



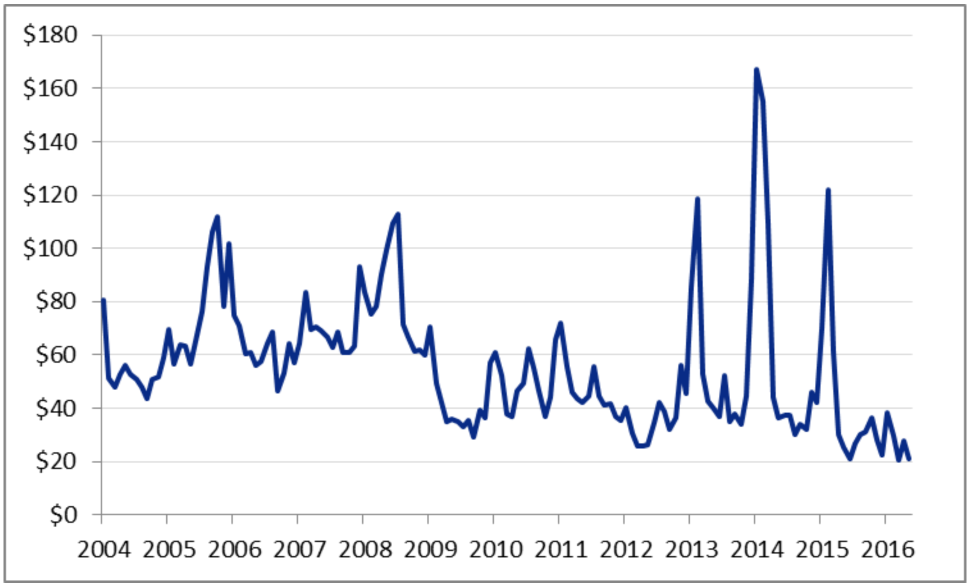
Source: Synapse Energy Economics, 2016.

3.3. Energy Revenues

Energy revenues depend on the amount of electricity that is produced and on wholesale energy market prices at the time when it is being produced. Forecasts of future energy prices will have a large impact on the revenue expectations and valuation of particular resources. This is especially true for hydro resources, which must account for both expected water flows and expected prices. Like water flows, energy market prices can vary substantially from year to year and from month to month. The graph below shows the monthly average energy prices in Vermont since 2004.[16] With the exception of recent spikes in wintertime prices, the trend in energy market prices in New England has been heading downward, reflecting the effects of declining natural gas prices, excess system capacity, and flattening of loads. Recent winter price spikes are tied to poor generator performance during cold weather and are not anticipated to continue after 2017 due to recently adopted changes to wholesale market rules.

[16] ISO-NE Standard Market Design (SMD) data archived data for each of the load zones and the entire New England system, including day-ahead and real-time demand and locational marginal pricing (LMP) information; system load; weather; and regulation clearing price data. http://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/zone-info.

Figure 5. Monthly Average Energy Prices in Vermont



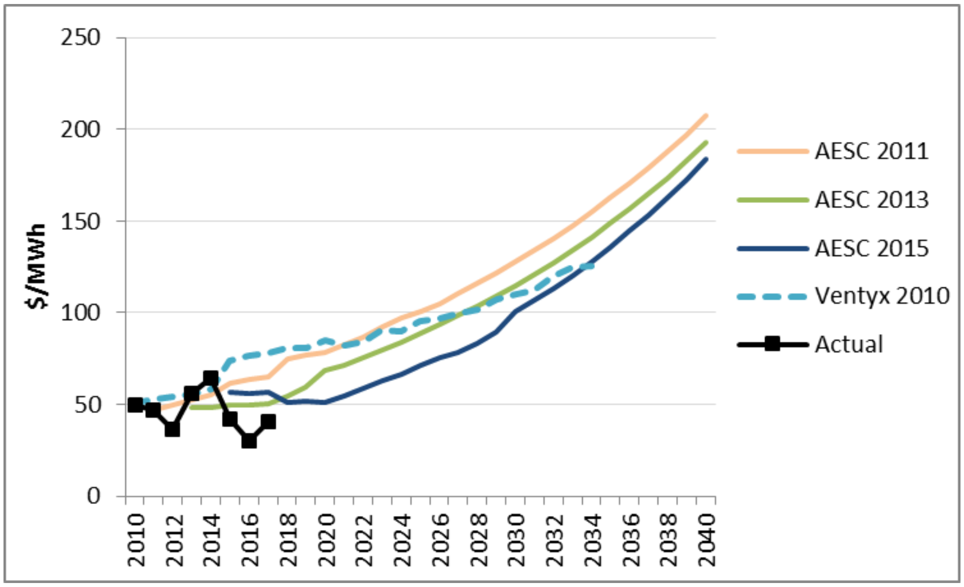
Source: Synapse Energy Economics, using ISO-NE SMD data.

As shown below, recent energy price forecasts are much lower than forecasts from when the Sansoucy valuations were done. The Ventyx 2010 forecast was used in the Sansoucy valuation of the Deerfield facilities.[17] Forecasts from the Avoided Energy Supply Costs (AESC) studies[18] estimate the value of energy saved from demand-side management measures on a biannual basis in New England and are the result of an extensive process among New England stakeholders. They represent an informed consensus forecast and, as shown below, they too have been trending downward in recent years. The bottom line shows the actual market prices up through 2015 and the futures market prices through 2017. Based on these forecasts and our analysis of recent energy price trends, we conclude that energy revenues for the TransCanada hydro facilities will likely be less than they were in previous years and will result in a proportional reduction in the valuations. Specifics of those adjustments will be discussed later in this report.

[17] The forecasted energy pricing used in this appraisal for the facilities are based on forecasts prepared by Ventyx, a leading independent energy forecaster in the United States. The price forecast is provided on monthly and annual basis for both on- and off-peak energy. These on-peak and off-peak price forecasts are provided to the appraiser(s) on a subscription basis for the New England-East (NE-East) and the New England-West (NE-West) regions of New England. – Sansoucy 2013, page 42.

[18] Avoided Energy Supply Cost Study Group. 2015. *Avoided Energy Supply Costs in New England: 2015 Report*. Available at www.ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report1.pdf.

Figure 6. Energy Price Forecasts – Vermont All-Hours Energy Price

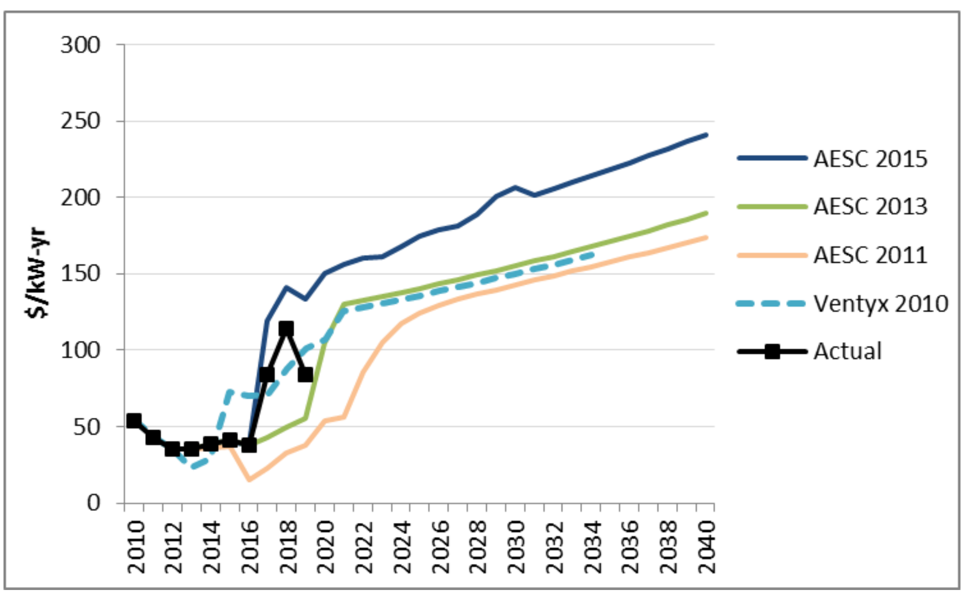


Source: Synapse Energy Economics, using AESC, Ventyx, and ISO-NE SMD data.

3.4. Capacity Revenues

Currently, capacity payments account for about one-fifth of the revenues for hydro facilities in New England. The capacity prices are determined three-years in advance through an auction process managed by ISO-NE. In previous auctions, capacity prices were fairly low, but, for a variety of reasons, recent auctions have resulted in much higher values. All of the forecasts shown below have predicted a significant increase in capacity prices—although the timing has varied.

Figure 7. Capacity Price Forecasts



Source: Synapse Energy Economics, using AESC, Ventyx data.

Capacity market design elements have changed more frequently and substantively than anticipated when the original capacity market design was approved by the Federal Energy Regulatory Commission (FERC) in 2006. Changes to the market design, specifically the administrative determinations of the cost of new entry and annual purchase quantities, are likely to continue to impact auction clearing prices and create uncertainty about capacity market revenues for these hydro facilities.

For example, the introduction of new pay-for-performance rules for capacity resources presents new risks. In simple terms, pay-for-performance rules introduce strong penalties for any resource that fails to deliver on its capacity supply obligation during emergency system conditions. At the same time, the rules allow resources that do perform to receive a portion of the penalty payments made by non-performers on a load-proportional basis. If the operational flexibility of the TransCanada facilities are limited, as is likely for the three lower Connecticut River facilities, those facilities may be reluctant to even participate in the capacity market, depending on how often emergency conditions are anticipated to occur. Alternatively, they may hedge such participation with bilateral contracts that would add costs. Because the pay-for-performance rules only recently became effective, in June 2016, we have no history on how the rules are affecting resource owners' decisions to either take on capacity supply obligations for their resources or hedge those obligations. It is another uncertainty as to the value of the TransCanada assets in the future, but one that we do not attempt to quantify in this preliminary valuation analysis.

If forecasted increases in capacity prices are realized, this could lead to a substantial increase in capacity market revenues for all the TransCanada hydro facilities—unless operational restrictions greatly reduce the capacity ratings of some facilities.

3.5. Renewable Energy Credit Revenues

The value of Renewable Energy Credits (REC), which states use to meet their Renewable Portfolio Standards (RPS), can vary considerably depending on the resource that produces the REC. There is not a significant New England market for RECs from existing hydroelectric resources, and consequently the value of these RECs is generally low.[19] However, 29.4 percent of Vernon and 3.01 percent of Comerford generation qualifies for Massachusetts Class 1 RECs. The ceiling price for these credits in 2014 was $66.16/MWh, and this is annually adjusted by the Consumer Price Index (CPI). These prices are more than double recent energy market prices and are a significant revenue boost for the qualifying facilities.

In Vermont, a Renewable Energy Standard (RES) will go into effect on January 1, 2017. RECs from all of the TransCanada hydro facilities are eligible for the program. The ceiling (defined by the alternative compliance payment) for that energy is set at $0.01 per kWh ($10/MWh). This will be adjusted for

[19] 100 percent of Deerfield 2-4, Searsburg, and Sherman qualifies for Massachusetts Class II RECs. All but Comerford and Moore qualify for Maine Class II RECs, and some portion of Deerfield 2 & 5, McIndoes, Searsburg, and Sherman qualifies for Rhode Island existing renewables RECs. Due the small size of the facilities, these RECs add very little to the overall value.

inflation using the CPI. While not as generous as the Massachusetts credits, this does represent a notable boost to the revenues for existing facilities.

3.6. Other Revenues

Other services that a hydro plant could provide are (a) real-time operating reserves, (b) forward reserves, and (c) power regulation.[20] The revenues associated with those markets are much less than those of the energy and capacity markets. Also, the facilities in this valuation are far from the load centers and most are unlikely to qualify to provide these services. While some facilities may receive modest revenues from these sources, we do not have access to that information and have not included it in this preliminary valuation.

3.7. Relicensing Considerations

The plants on the Deerfield River were relicensed by FERC in 1997 for a 40-year period. Therefore, the next relicensing for these facilities will not occur until 2037. The plants on the Upper Connecticut River (Moore, Comerford, and McIndoes) completed relicensing in 2002, so the next relicensing year for them is 2042. All of these facilities, at the time they undergo relicensing, will be subject to new water quality standards adopted by the State of Vermont in 2000 (and any additional standards that may be adopted in the interim).

Three plants on the Lower Connecticut River (Wilder, Bellows Falls, and Vernon) are currently undergoing the relicensing process, with the new licenses expected to be issued in 2019. One of the key elements of the Federal dam relicensing process is a certification by relevant state agencies that the dam is operated to meet state water quality standards. In the case of the three Lower Connecticut River dams, this will require compliance with both Vermont and New Hampshire water quality standards. For this report, we focus primarily on Vermont Water Quality Standards as determined by the Vermont Agency of Natural Resources (ANR) and as applied to a recent federal relicensing review of the Waterbury, VT dam and related facilities in 2014. New Hampshire may impose additional conditions based on the New Hampshire Water Quality Standards. Therefore it is necessary to conduct additional analysis of possible requirements in order to provide a more comprehensive prediction of potential energy production and gross capacity revenue reductions.

The Vermont Water Quality Standards require that waters be managed to support designated uses, achieve water quality criteria, and maintain and protect high quality bodies of waters. The version of the Vermont Water Quality Standards currently in place requires hydroelectric facilities to operate in a manner that results in only minimal deviation from natural flow regimes. The standards allow for

[20] See ISO New England's Internal Market Monitor, 2015 Annual Markets Report.

reservoirs and impoundments to exhibit artificial variations, but only to the extent that such variations ensure full support of uses.[21]

The impact of these relicensing requirements will likely mean that inflows and outflows from any reservoirs or ponding facilities should match on an instantaneous basis. This change of operation will reduce the ability to coordinate the release of water, and therefore generation, with times of high, on-peak power prices. It will likely also affect the capacity rating of the facilities, which is determined by generation levels during summer and winter on-peak hours. A review of the recent relicensing of the Waterbury, VT hydro facilities (2014 decision) confirms that this is a probable result for TransCanada's three Lower Connecticut River facilities.[22]

ANR has advised the Vermont Hydroelectric Power Acquisition Working Group that it will likely require modification to the current operation of the three Lower Connecticut River facilities up for relicensing—Wilder, Bellows Falls, and Vernon—to accommodate increases in minimum water flow requirements and restrictions on flow variations.[23] The three Lower Connecticut River facilities currently operate on a daily peaking cycle to maximize weekly on-peak energy revenues. In general, peak power prices occur between noon and 7pm, with peak prices on business days exceeding peak prices on weekends and holidays. In order to meet Vermont Water Quality Standards, these Connecticut River facilities will need to operate in more of a run-of-river mode.

ANR estimates that these operational changes may reduce the energy revenue of the Connecticut River facilities currently undergoing relicensing by as much as 30 percent.[24] The ANR report does not account for the potential for the capacity ratings of the Lower Connecticut River facilities to be reduced due to the same operational changes. The scope of the revenue impacts will not be known until the relicensing process is completed, but the result of that process will likely be reductions in both energy and capacity revenues, and therefore, reduced income for these three facilities.

The two large upstream reservoirs (associated with the three Upper Connecticut River dams) are not subject to relicensing until 2042, and they will continue to be operated in a daily peak/weekly cycle manner. Once water is released upstream, it is a matter of time (8–14 hours) before the water reaches the three Lower Connecticut River dams. Due to the large size of the Upper Connecticut River facilities, the reservoir releases will probably be timed for peak hours at those facilities to maximize revenues. Assuming that relicensing conditions will require the three Lower Connecticut River facilities to pass

[21] Vermont Water Quality Standards Section 3-01(C)(3).

[22] The Waterbury facility will also install a lower capacity turbine that may further reduce its capacity rating; the small turbine may also contribute to more bypass flows and, therefore, an overall reduction in energy production. See VT Agency of Natural Resources Water Quality Certification, December 11, 2014.

[23] See ANR Memo to Hydroelectric Power Acquisition Working Group May 5, 2016. The memo is included as Appendix B, along with this valuation as Appendix A, in the Draft Report to the Legislature.

[24] Ibid, page 12.

outflows that match inflows, these three facilities will be unable to store water in order to generate electricity during high-priced peak hours.

For the purposes of this valuation study, we are assuming that the three Lower Connecticut River facilities will be operated as run-of-river facilities and, therefore, experience reductions to their annual energy and capacity revenues. We provide an estimate of possible revenue impacts due to operational changes in Section 4. Our low estimate is a 10 percent reduction in energy revenues and a 25 percent reduction in capacity rating. This assumes that the three Lower Connecticut River facilities will still be able to utilize much of the water flow from the operation of the Upper Connecticut River facilities. Our high estimate is a 30 percent reduction in energy revenue and a 50 percent reduction in capacity rating. This assumes that the three Lower Connecticut River facilities will have to spill (that is, let the water flow through without generating electricity) the water flows resulting from the Upper Connecticut River facilities in order to operate closer to a true run-of-river mode and to comply with the Vermont Water Quality Standards.[25] These are preliminary estimates made with the information available today. As the relicensing process for the three Lower Connecticut River facilities proceeds and more details are available, these estimates can be revised.

It is important to note that every hydro facility is unique and that operational changes necessary to meet Vermont Water Quality Standards could vary from one facility to another. However, it is equally important to note that ANR determinations of how to meet Vermont Water Quality Standards are driven by water science; the agency is expressly prohibited from considering the economic impacts of operational changes. And, as mentioned earlier, FERC has no authority to overrule or adjust a state's water quality certification conditions. The FERC license must include both Vermont and New Hampshire state water quality certification conditions.

3.8. Operating and Capital Costs

Operating and capital costs for hydro facilities tend to be stable and predictable. Such costs tend to be fixed; they are related to staffing and maintenance needs and are not very dependent on generation levels. While there are occasional major replacement and structural costs, these can often be anticipated and budgeted for in advance. Note also that costs vary by facility as each is unique. We do not have access to much detail regarding recent and anticipated future costs for these facilities, although the authorized bidders will see this information before they make their offers. The Sansoucy 2012 valuation, although redacted, does provide some general cost numbers for the six Upper

[25] Our range of estimated revenue reductions for the three Lower Connecticut River facilities is very dependent on the meaning of "run-of-river" operation. If it is simply "match outflows with inflows," then all the water released by the Upper Connecticut River facilities, which are operated on a weekday peaking schedule, will have to be instantaneously released by the Lower Connecticut River facilities. This is the basis for our high estimate of revenue reductions. However, if the Water Quality Standards allow the three Lower Connecticut River facilities to operate in a modified "run-of-river" condition to mitigate the large peaking flows from the Upper Connecticut River facilities, then the impact on energy and capacity revenues will be reduced.

Connecticut River facilities.[26] The basic takeaway from these numbers is that expenses are about one-third of the gross revenues. In the absence of more specific information, we use that one-third ratio to update the current valuations from the previous Sansoucy study results.

Table 6. Facility Expense Parameters

Expense Parameters Connecticut River Valuation Report 2012	O&M General Expenses	Annual Capital Expenses	Relicensing Expenses over License Period	Total 2012 Estimated Expenses	Expense/ Revenue 2012
Facility	**$/kW Capacity**	**% of Value**	**$/Year**	**$1,000**	**%**
Moore Development	26	1.0%	-	$ 6,812	32%
Comerford Development	38	1.0%	-	$ 8,065	37%
McIndoes Development	85	0.5%	-	$ 1,025	47%
Wilder Station	60	0.5%	38,000	$ 2,625	34%
Bellows Falls Station	69	1.0%	38,000	$ 4,194	37%
Vernon Station	79	0.5%	38,000	$ 3,174	29%
Total Estimated Expenses and Average Expenses as a Percent of Revenue				**$ 25,895**	**34%**

Source: Synapse Energy Economics, 2016.

[26] Sansoucy 2013, Valuation Summary pages 1-12.

4. UPDATED VALUATIONS

4.1. Key Considerations

In this update, we used the "income approach" to update the valuation of the facilities based on current expectations of future revenues. We looked at the changes in both energy and capacity prices that were discussed previously in Sections 3.3 and 3.4. The basic approach was to look at the 20-year levelized differences in energy and capacity prices and use that to adjust the previous valuations.[27] We note that we did not have all the details about what went into the original valuations, so we have used our professional judgment to develop the assumptions that were used in this analysis, including:

- Currently expenses are one-third of the gross revenues and will continue at roughly that ratio in the future.
- Energy payments are the largest portion of the current revenues, and represent 78 percent of the Connecticut River plant revenues and 83 percent of the Deerfield River plant revenues.
- The remaining revenues are associated with capacity payments.
- Vermont Renewable Energy Credits will provide an additional revenue source in the future.

4.2. Adjustments Based on Market Forecast Changes

The table below identifies the major system operation and revenue factors used to adjust the previous Sansoucy valuations. These adjustments are based on current plant operations and market expectations. Further adjustments are made for changes in REC eligibility and relicensing impacts in later sections.

Table 7. Facility Operation and Revenue Characteristics

Hydro Facilities	Capacity (MW)	Average Generation (MWh)	Sansoucy Valuation (M$)	Valuation Date	Energy Revenue (%)	Capacity Revenue (%)	Expense/ Revenue Fraction
Connecticut River	484	1,237,200	$820	2012	78%	22%	33%
Deerfield (VT)	45	124,420	$87	2010	83%	17%	33%
Deerfield Total[28]	84	286,950	$176	2010	83%	17%	33%

Source: Synapse Energy Economics, 2016.

[27] Note that this methodology automatically adjusts for inflation effects.

[28] Deerfield total extrapolated from Sansoucy Deerfield Vermont valuations based on historical facility generation.

In order to calculate the energy and capacity revenue changes, we evaluated energy and capacity market forecasts both from when the previous valuations were performed and those currently available. The gross revenue change represents the combined effects of expected energy and capacity market changes. The net revenue change is the gross revenue change after subtracting expenses.

To compare the effects of these forecast changes, we calculated the 20-year net present values (NPV) of each forecast. These NPVs represent the long-term revenue stream and indicate the likely changes in the plant energy or capacity revenue.[29] We find that current expectations of energy revenues are about 3 to 13 percent lower than when the Sansoucy valuations were done. However, capacity revenue expectations are currently about 64 to 111 percent higher.

We find that the net revenues of the Connecticut River facilities would increase between 14 and 36 percent compared to the previous valuation. In addition, the net revenue of the Deerfield River facilities would increase between 0.3 and 21 percent compared to their previous valuation. The table below shows the ratios of the NPVs of current forecasts versus those of the original valuations. To represent a reasonable degree of uncertainty, we have calculated low and high ratios for the energy and capacity revenues. Note that energy revenue expectations are down, reflecting the lower prices primarily associated with lower natural gas prices.

The capacity revenue expectations are up considerably, reflecting the higher expectations shown in Figure 7 above. However, ISO-NE capacity markets have been, and will likely continue to be, quite volatile. They are also dependent on the specifics of market rules and design, which are subject to change.

Table 8. Relative Forecast Changes

	Energy NPV Change Ratio		Capacity NPV Change Ratio		Gross Revenue Change		Net Revenue Change	
Hydro Facilities	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Connecticut River	0.89	0.99	1.81	2.11	9.3%	23.7%	13.9%	35.6%
Deerfield River	0.87	0.97	1.64	1.94	0.2%	13.7%	0.3%	20.5%

Source: Synapse Energy Economics, 2016.

These changes in net revenue were then used to adjust the previous Sansoucy valuations. The new valuations range from being close to the previous ones (for the Deerfield stations) to about a third higher (for the Connecticut stations). The table below shows the updated valuations.[30] As indicated

[29] For the NPV calculations we used the same 7 percent nominal discount rate as in the 2012 Sansoucy report.

[30] Sansoucy original values converted to 2016 dollars using a 2 percent inflation rate.

previously, the increases are associated with capacity market revenue, which has a high degree of uncertainty. The energy market revenues are slightly below what was previously expected.

Table 9. Updated Valuations Based on Current Market Forecasts

				Updated 2016 Valuation (M$)	
Hydro Facilities	**Capacity (MW)**	**Generation (MWh)**	**Sansoucy Valuation (M$, 2016$)**	**Low**	**High**
Connecticut River	484	1,237,200	$888	$934	$1,112
Deerfield River	84	286,950	$205	$182	$219
CT & Deerfield Total	**553.5**	**1,524,150**	**$1,092**	**$1,117**	**$1,331**

Source: Synapse Energy Economics, 2016.

4.3. REC and Relicensing Adjustments

Renewable Energy Payments

As mentioned previously, 29.4 percent of Vernon and 3.01 percent of Comerford generation qualify for Massachusetts Class 1 RECs. This represents a substantial revenue benefit, especially for Vernon. If other hydro facilities are also able to qualify for these higher priced REC values, the upside could be significant. At this time, however, we are not aware of any additional facilities that would qualify.

In addition, each MWh generated by the dams will produce RECs eligible for compliance for Vermont's RES; the ceiling price for these RECs is $10/MWh, although the actual value will fluctuate with market demand. At $10/MWh, we estimate that Vermont's RES has the potential of increasing the value of the qualifying plants by 20 percent.

Relicensing Impacts

As described above, the three plants on the Lower Connecticut River (Wilder, Bellows Falls, and Vernon) are currently undergoing the FERC relicensing process.[31] Although the impact on potential revenue and value of those plants is uncertain, our preliminary valuation provides a range of estimates of how relicensing may impact the potential energy production and capacity revenues. The estimates are based on the assumption that these plants will be relicensed to be more like run-of-river facilities with no reservoir cycling. Because the water flows into the Lower Connecticut River facilities are determined by the operation of the upstream facilities, run-of-river operation of the Lower Connecticut River facilities would significantly reduce the possibility of timing generation of these three plants for higher energy prices. In that event, we estimate a potential reduction of as much as a 30 percent in gross energy revenues for these three facilities. Furthermore, if no reservoir cycling is allowed, the capacity value of

[31] As per the 2012 Sansoucy report, the lower facilities represent 42 percent of the Connecticut River plant values.

these plants may be substantially reduced. We estimate a 50 percent reduction in gross capacity revenues if relicensing requires strict run-of-river operations. Combined, the reductions in gross energy and capacity revenues could reduce the valuations of the three Lower Connecticut River facilities by 50 percent. [32] A 50 percent reduction in value of the three Lower Connecticut River facilities would, in turn, lower the overall valuation of the Connecticut River system facilities by about 20 percent.

If the relicensing process allows for some limited impounding and cycling of water flows from the Upper Connecticut River facilities, then we estimate a 10 percent reduction in the energy revenues and a 25 percent reduction in capacity revenues for these three Lower Connecticut River facilities. The impact on the overall valuation of the Connecticut River facilities would be about 10 percent.

As part of the water quality certification process, the owner of the facilities could undertake improvements to each facility that could increase revenues in light of these new operational requirements. In the re-licensing determination for the Waterbury facilities, one of the changes was the installation of a new, smaller turbine that would operate more efficiently at low-speed water flows.[33] Other dam re-licensing determinations in Vermont have seen owners opting for smaller, more efficient turbines to improve revenues from run-of-river operation. It is also possible that the new operation requirements for the three Lower Connecticut River relicensing proceedings could allow those facilities to qualify more output as meeting MA Class 1 payment levels.

[32] The relative changes in net revenues (and plant value) are much greater than the changes in total revenue because of the plant costs, which currently are about one-third of the total revenues.

[33] Op.cit., ANR Certification pages 5 and 25.

4.4. Updated Range of Valuations

Putting all the pieces together produces a range of current valuations for these hydro facilities. From a market perspective, the overall value of these assets has increased since they were last evaluated. This is due in large part to the expectation of higher capacity prices as well as the facilities' ability to qualify for Vermont REC payments. However, there is potential for considerable downside for the three Lower Connecticut River facilities that are currently going through the federal relicensing process, which will likely lower both energy and capacity revenues. Potential bidders may lower their offers because of that significant uncertainty.[34]

Table 10. Valuation Ranges Based on Forecast and Other Possible Changes

		Updated 2016 Valuation (M$)		VT REC Payment Impacts (M$)		Relicensing Impacts for Lower CT (M$)		Range of Possible Valuations (M$)	
Hydro Facilities	**Sansoucy Valuation (M$)**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Connecticut River	$888	$934	$1,112	$54	$128	-$198	-$113	$791	$1,127
Deerfield River	$205	$182	$219	$8	$19			$190	$238
CT & Deerfield Total	**$1,092**	**$1,117**	**$1,331**	**$62**	**$147**	**-$198**	**-$113**	**$981**	**$1,364**

Source: Synapse Energy Economics, 2016. All values in 2016 dollars.

[34] For impacts, the "Low" column indicates the change that results in the lowest value, i.e. smallest increase or greatest decrease, and the "High" column for the greatest value.

APPENDIX B – AGENCY OF NATURAL RESOURCES MAY 4, 2016 MEMORANDUM

ANR REPORT: Natural Resources Issues for Relicensing TransCanada's Three Dams on the Lower Connecticut River
May 4, 2016

Outline of Report:

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1. Purpose Statement and Anticipated Changes

This report is intended to provide the Vermont Hydropower Working Group with information regarding the Federal Energy Regulatory Commission (FERC) licensing and Section 401 certification process for three TransCanada dams on the lower Connecticut River and potential reductions in generation or revenue to these facilities that may occur as a result of this process.

The Vermont Agency of Natural Resources (ANR) has limited information regarding these facilities and has therefore made assumptions in order to make a recommendation. TransCanada has not yet submitted a preliminary application to FERC or completed all environmental studies necessary for the resource agencies to commence environmental review. Once the reports are received, it could take over a year for the resource agencies to complete their review and it is possible that the resource agencies will request additional studies. In addition, these facilities implicate waters regulated by both Vermont and New Hampshire. As a result, the New Hampshire Department of Environmental Services (NHDES) will need to conduct its own environmental review of the facilities and may impose conditions in addition to the conditions that Vermont is likely to require.

ANR offers recommendations based on recent relicensing processes undergone by hydroelectric facilities in Vermont, as well as the information available regarding the TransCanada facilities. Based on this information, TransCanada's facilities will likely be required to reduce or eliminate peaking operations and operate the facilities in a manner that is more consistent with run-of-river flows. These changes will have a significant impact on the amount of electricity generated.

The facilities' current licenses are decades old and therefore the facilities have not undergone environmental review under modern environmental law. Contemporary environmental law is significantly more stringent and typically requires higher minimum conservation flows and the reduction or elimination of water level fluctuations associated with peaking practices. In recent cases where older facilities have undergone environmental review associated with relicensing, ANR has required significant increases in minimum conservation flows and reductions in water level fluctuations in order to find reasonable assurance that the facilities will not violate applicable water quality standards. The impacts of increased conservation flows could be reduced generation or reduced revenue due to timing restrictions. In addition, other infrastructure investments may be necessary to implement these required operational changes.

As a result, ANR recommends that the Vermont Hydropower Working Group anticipate that the relicensing process for TransCanada's dams on the lower Connecticut River will result in a significant reduction in revenue for these facilities, potentially as much 30 percent.

2. Information Available and Reviewed to-date

Current Status of the FERC Licenses:

Lower Connecticut River

- TransCanada owns and operates three facilities on the Lower Connecticut River with FERC licenses that will expire in April 2019. These facilities are Wilder, Bellows Falls, and Vernon. Each facility currently operates under its own FERC license.
- FERC's licensing review process is currently underway, but TransCanada has not yet filed the license application. The applicant's preliminary licensing proposal is due to FERC in December 2016 and the FERC license proposal is due in April, 2017.
- The applicant has completed the field work necessary for the environmental review process, but the resource agencies and FERC have not received all of the reports yet and do not expect to receive them until August, 2016. Once these reports are received, the resource agencies will review and request additional studies if they determine that additional studies are necessary. For example, the resource agencies submitted a comment letter to FERC on May 2, 2016 requesting that FERC require the applicant to do an additional year of study to assess upstream eel passage at all three of the lower Connecticut River facilities, as well as an additional aesthetics study at the Bellows Falls facilities. The resource agencies include Vermont Agency of Natural Resources (ANR), as well as the U.S. Fish & Wildlife Service (USFWS), the National Oceanic and Atmospheric Administration (NOAA), NHDES, and the New Hampshire Fish and Game Department (NH Fish & Game).

Deerfield River

- TransCanada owns and operations eight facilities on the Deerfield River. Three of the facilities are in Vermont (Somerset, Searsburg, and Harriman) and five are located in Massachusetts (Sherman, Deerfield No. 2, Deerfield No. 3, Deerfield No. 4, and Deerfield No. 5).

- FERC issued a 40-year license for all of the facilities as part of one project license on April 4, 1997. As a result, the license will expire in the year 2037 and the relicensing process will begin 5.5 years prior to the license expiration. The 2000 revisions to the Vermont Water Quality Standards added new requirements that affect hydropower facilities, such as the hydrology policy, the hydrology criteria, and more specifics regarding aquatic biota and habitat. Therefore, the relicensing process will likely result in required operational changes to comply with modern environmental law.

Upper Connecticut River

- TransCanada owns Fifteen Mile Falls, which is a complex of three facilities (Moore, Comerford, and McIndoes) on the Connecticut River.
- FERC issued a 40-year license for all of the facilities as part of one project license on April 8, 2002.[1] As a result, the license will expire in the year 2042 and the relicensing process will begin 5.5 years prior to the license expiration. Since the license was issued after the 2000 amendments to the Vermont Water Quality Standards but as the result of a settlement agreement, it is likely that the relicensing process for this complex will still require some operational changes to comply with modern environmental law.[2]

Site-Specific Information about the Lower Connecticut River Facilities:

Vernon Facility

- The Vernon facility is currently operated as a peaking plant.[3] The minimum flow required under the current license is 1250 cfs and the peak generation flow is 14,250 cfs.
- The Vernon facility's maximum generation capacity is 32.4 MW and the facility's average annual generation is 137,344 MWH.[4]

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[1] The water quality certification issued to the Fifteen Mile Falls complex was the result of a settlement agreement between USGenNE (the previous owner of the facilities), the State of Vermont, the State of New Hampshire, U.S. Fish & Wildlife Service, the Environmental Protection Agency, the National Park Service, Appalachian Mountain Club, the Connecticut River Joint Commission, the Connecticut River Watershed Council, Conservation Law Foundation, the New Hampshire Rivers Council, the New Hampshire Council of Trout Unlimited, and the Northeast Chapter of Vermont Trout Unlimited.

[2] For example, the license requires that the Licensee conduct studies on water quality and develop a number of different management plans that address fisheries, plant communities, threatened and endangered species, recreation, and cultural resources. Depending on the studies done as part of the relicensing process, Vermont and New Hampshire may determine that the management plans are insufficient to meet water quality standards and additional conditions are necessary.

[3] It is unclear to ANR whether the facility is designed to operate strictly as a peaking plant or whether it could operate over the course of more hours at lower output during those hours, as opposed to optimizing production during peak hours.

[4] This data and the data presented in tables regarding average generation and average discharges at the Vernon facility is extracted from pages 2-36 and 2-37 of TransCanada's October 2012 Pre-Application Document for the Vernon Project.

- The environmental concerns applicable to this facility include:
  - Reservoir water level fluctuations. The facility currently operates as a peaking plant that requires significant fluctuations to the reservoir level. The resource agencies are very likely to require a reduction in water level fluctuations in order to better protect littoral habitat. The amount of the reduction will depend on the information provided in the applicant's habitat studies.
  - Downstream flows. The facility's peaking regime results in pulsing flows downstream. The resource agencies are very likely to require an increase in minimum downstream flows, which will result in less water being stored in the reservoir during drier months. The specific flows requirements will depend on the information provided in the applicant's habitat studies.
  - Eel passage. The resource agencies have already identified that eel passage needs additional study and will be filing a comment letter to FERC requesting that FERC require the applicant to do an additional year of study to assess upstream eel passage at the Vernon facility. Depending on the information provided in these studies, the resource agencies may require modification or additional upstream passage facilities to provide safe, timely and effective passage for eels.
  - American Shad passage and spawning habitat. The resource agencies have not yet received reports on the adult and juvenile American Shad population. Depending on the information provided in these studies, the resource agencies may require modifications to the upstream fish passage facilities or habitat protection measures, such as flow requirements.

Average generation in MWH by month (years 2000-2012)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
12,269	10,041	13,903	13,144	15,375	12,389	9,325	8,692	6,547

Average generation in MWH by month (years 2000-2011)[5]

Oct	Nov	Dec					
9,955	12,746	12,959					

Average discharges in cfs by month (years 2000-2012)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
10436	7481	16804	29064	17725	11273	7083	6874	5303

[5] TransCanada had not yet collected data for October-December 2012 when assembling its October 2012 Pre-Application Document and therefore these monthly averages are based on data collected from years 2000-2011.

Average discharges in cfs by month (years 2000-2011)[6]

Oct	Nov	Dec					
11752	13367	14037	12821				

Wilder Facility

- The Wilder facility is currently operated as a peaking plant.[7] The minimum flow required under the current license is 675 cfs and the peak generation flow is 12,000 cfs.
- The Wilder facility's maximum generation capacity is 36.6 MW and its average annual generation is 158,469 MWH.[8]
- The environmental concerns applicable to this facility include:
  - Reservoir water level fluctuations. The facility currently operates as a peaking plant that requires significant fluctuations to the reservoir level. The resource agencies are very likely to require a reduction in water level fluctuations in order to better protect littoral habitat. The amount of the reduction will depend on the information provided in the applicant's habitat studies.
  - Downstream flows. The facility's peaking regime results in pulsing flows downstream. The resource agencies are very likely to require an increase in minimum downstream flows, which will result in less water being stored in the reservoir during drier months. The specific flows requirements will depend on the information provided in the applicant's habitat studies.
  - Endangered species. The federally listed endangered Dwarf wedge mussel has been found downstream of the Wilder facility and upstream of the Bellows Falls facility. Therefore, USFWS will determine what critical habitat must be protected after the applicant files the report with FERC. In addition, the state listed endangered Cobblestone tiger beetle has been found to be present in waters affected by all three facilities, so ANR will need to assess the potential impacts of the project on this state listed species.

[6] TransCanada had not yet collected data for October-December 2012 when assembling its October 2012 Pre-Application Document and therefore these monthly averages are based on data collected from years 2000-2011.
[7] It is unclear to ANR whether the facility is designed to operate strictly as a peaking plant or whether it could operate over the course of more hours at lower output during those hours, as opposed to optimizing production during peak hours
[8] This data and the data presented in tables regarding average generation and average discharges at the Wilder facility is extracted from pages 2-34 and 2-35 of TransCanada's October 2012 Pre-Application Document for the Wilder Project.

Average generation in MWH by month (years 2000-2012)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
13,245	9,164	16,097	20,468	18,858	12,522	9,765	8,963	7,293

Average generation in MWH by month (years 2000-2011)[9]

Oct	Nov	Dec					
12,158	14,904	15,031					

Average discharges in cfs by month (years 2000-2012)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5728	3754	5679	5702	5295	6874	6783	5563	7381

Average discharges in cfs by month (years 2000-2011)[10]

Oct	Nov	Dec					
6486	6234	699					

<u>Bellows Falls Facility</u>

- The Bellows Falls facility is currently operated as a peaking plant.[11] The minimum flow required in the current license is 1083 cfs and its peak generation flow is 12,300 cfs.
- The Bellows Falls facility's maximum generation capacity is 40.8 MW and its average annual generation is 248,887 MWH.[12]
- The environmental concerns applicable to this facility include:
  - Reservoir water level fluctuations. The facility currently operates as a peaking plant that requires significant fluctuations to the reservoir level. The resource agencies are very likely to require a reduction in water level fluctuations in order

[9] TransCanada had not yet collected data for October-December 2012 when assembling its October 2012 Pre-Application Document and therefore these monthly averages are based on data collected from years 2000-2011.
[10] TransCanada had not yet collected data for October-December 2012 when assembling its October 2012 Pre-Application Document and therefore these monthly averages are based on data collected from years 2000-2011.
[11] It is unclear to ANR whether the facility is designed to operate strictly as a peaking plant or whether it could operate over the course of more hours at lower output during those hours, as opposed to optimizing production during peak hours.
[12] This data and the data presented in tables regarding average generation and average discharges at the Bellows Falls facility is extracted from pages 2-34 and 2-35 of TransCanada's October 2012 Pre-Application Document for the Bellows Falls Project.

to better protect littoral habitat. The amount of the reduction will depend on the information provided in the applicant's habitat studies.
    - Downstream flows. The facility's peaking regime results in pulsing flows downstream. The resource agencies are very likely to require an increase in minimum downstream flows, which will result in less water being stored in the reservoir during drier months. The specific flows requirements will depend on the information provided in the applicant's habitat studies.
    - Endangered species. The federally listed endangered Dwarf wedge mussel has been found downstream of the Wilder facility and upstream of the Bellows Falls facility. Therefore, USFWS will determine what critical habitat must be protected after the applicant files the report with FERC.
    - Bypass reach flows. The Bellows Falls facility has a bypass reach in which TransCanada currently only passes leakage. The resource agencies are very likely to require minimum flows in the bypass reach, which may mean a reduction in power generation unless a turbine is installed.
- Historic Preservation. Petroglyphs are present in the bypass reach, so historical preservation measures may be required. Historic preservation is outside the scope of this report.

Average generation in MWH by month (years 2000-2012)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
22,204	16,795	24,484	27,755	28,438	22,458	16,485	14,323	11,406

Average generation in MWH by month (years 2000-2011)[13]

Oct	Nov	Dec						
18,317	22,674	23,547						

Average discharges in cfs by month (years 2000-2012)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
8565	6134	12674	24382	14492	9100	6108	5886	4299

[13] TransCanada had not yet collected data for October-December 2012 when assembling its October 2012 Pre-Application Document and therefore these monthly averages are based on data collected from years 2000-2011.

Average discharges in cfs by month (years 2000-2011)[14]

Oct	Nov	Dec					
9744	10675	11138					

3. Information Not Yet Available for Review

- Environmental studies are needed to establish a baseline for the state environmental review and not all studies have been completed.
- Information regarding the facilities' structural assessments are unavailable because this information is held as classified Critical Energy Infrastructure Information (CEII) under the Patriot Act. FERC requires licensees to conduct structural assessments under a FERC Part 12D inspection every five years, so the information exists but is inaccessible to ANR at present.

4. Assumptions Made and Caveats

Assumptions Made

- Based on recent relicensing processes, peaking will likely be reduced or eliminated and operations that are more consistent with run-of-river may be required, which will have a significant impact on the amount of electricity generated. Recent relicensing processes include Waterbury Dam and the Morrisville Water & Light facilities.
- Certain upgrades are likely needed to address environmental concerns at the three facilities:
  - Bellows Falls facility will need to ensure minimum flows are passed in the bypass reach. As a result, TransCanada may determine that a new bypass flow turbine should be installed to ensure flows being passed could also generate power.
  - Depending on the operational and flow management requirements set by the resource agencies, TransCanada may need to install different or additional turbines at the facilities to pass the appropriate flows. This situation would arise if a hydraulic gap exists between the lowest quantity of flows that can be passed by the peaking turbines and the maximum flows that can be passed by the current low flow turbines.
  - The fish ladder facilities will need to be operated and improved at all three projects to pass anadromous species in a safe, timely, and effective manner.

[14] TransCanada had not yet collected data for October-December 2012 when assembling its October 2012 Pre-Application Document and therefore these monthly averages are based on data collected from years 2000-2011.

- All facilities will need to upgrade the present track racks to trash racks with smaller openings to prevent fish entrainment and impingement. For example, the trash rack at Wilder is currently 5.5" and a 1" track rack is necessary to prevent fish mortality.

Caveats

- TransCanada has not yet submitted a preliminary application to FERC or completed the requisite environmental studies, and the resource agencies have not received the reports necessary to commence environmental review. Once the reports are received, it could take over a year for the resource agencies to complete their review, and it is possible that the resource agencies will request that FERC require additional studies.
- The assumptions made in this report are based on the recent relicensing processes that have occurred in Vermont for hydroelectric facilities operating under older FERC licenses that did not require the current level of environmental review. These facilities include the Waterbury Dam and the Morrisville Water & Light dams.
- Other states may require additional conditions beyond those required by Vermont. New Hampshire will also need to review all licensing proposals for the Wilder, Bellows Falls, and Vernon facilities as well as the Fifteen Mile Falls facilities and Massachusetts will need to review all licensing proposals for the Sherman, Deerfield No. 2, Deerfield No. 3, Deerfield No. 4, and Deerfield No. 5 facilities on the Deerfield River. It is possible that these states may require additional conditions beyond those required by Vermont.
- The anticipated requirements to increase conservation flows and reduce water level fluctuations are likely to result in a reduction of generation capacity or timing restrictions. However, TransCanada could minimize these losses by investing in infrastructure upgrades, such as a turbine for the Bellows Falls bypass reach, that optimize power generation. Because the specific conditions necessary for compliance with modern environmental law are still unknown, it is impossible to speculate what amount of loss could be abated by infrastructure upgrades or other optimization measures.

5. Regulatory Requirements

General Regulatory Requirements

Federal Law

- **Federal Power Act and the FERC Process**. FERC's jurisdiction to license hydroelectric facilities derives from the Federal Power Act. As part of the licensing review process, FERC must conduct an environmental assessment that analyzes the consequences of issuing a license and reasonable alternatives to issuing the license. FERC receives comments from resource agencies and issues a final EA prior to issuing a license. *See* attached flowchart.

- **Clean Water Act**. Under Section 401 of the Clean Water Act, states must certify or waive certification that federal license applicant facilities' operations will comply with substantive provisions of the Clean Water Act. Vermont and New Hampshire must both review and certify the facilities prior to facilities obtaining FERC licenses.
- **Endangered Species Act**. FERC is required to consult with USFWS and NOAA to ensure that the licensed activity will not jeopardize the continued existence of listed species or adversely impact listed species or their habitat. USFWS and NOAA share jurisdiction for implementing the ESA and USFWS is taking the lead in reviewing the TransCanada projects on the Lower Connecticut regarding the Dwarf wedge mussel. If USFWS determines that the listed species or their habitat may be adversely impacted, USFWS may set conditions to protect and recover the species in the form of reasonable and prudent alternatives (RPA) or measures (RPM). FERC typically includes such conditions in the issued license.

<u>State Law</u>

- **Vermont Water Quality Standards**. The VWQS require that water uses are protected and maintained, that water quality criteria are achieved, and that high quality waters are maintained. The VWQS also include a hydrology policy and hydrology criteria that require that any interruption of natural flow regime or fluctuation of water levels resulting from the operation of dams, diversion, and other control structures not prevent the full support of uses. Applicants typically conduct a site-specific flow determination to make this demonstration.
    - The uses that must be protected and maintained at the Connecticut River waters include recreation, aesthetics, and aquatic biota, wildlife, and aquatic habitat.
    - The water quality criteria that must be achieved in the Connecticut River waters include the aquatic habitat, aesthetics, dissolved oxygen, and temperature criteria.
    - A 401 certification from Vermont is likely to include conditions such as minimum flows, water level fluctuation reductions or elimination, water quality monitoring, and other operational requirements necessary to ensure that the VWQS are met.
- **Vermont Endangered Species Act**. If there is a reasonable likelihood that the project will result in a take of the state listed species, such as the Cobblestone tiger beetle, then conditions to protect and recover the species will be required as part of the 401 certification. Such conditions might include a habitat conservation plan or operational changes that minimizes and mitigate harm to the impacted species during operations.
- **New Hampshire Water Quality Standards**. The NHWQS also require that water uses be protected, numeric and narrative criteria are achieved, and high quality waters

be maintained. However, ANR cannot opine on what NHDES may require as a result of its review process.

Site-Specific Regulatory Requirements

- Based on the examples of the recent facilities that have undergone relicensing, the resource agencies are likely to require an increase in minimum stream flows downstream of the facilities and in the bypass reach at Bellows Falls, in order to protect aquatic biota and habitat, including the endangered species. The resource agencies will also likely require minimum flows to ensure that aesthetics and recreation uses are supported.
- For the same reasons listed above, the resource agencies are likely to require increased seasonal conservation flows.
- The resource agencies are also likely to require a reduction or elimination of water level fluctuations of the impoundments and generation flows. The reduction or elimination of water level fluctuations may be required to support littoral aquatic biota and habitat.
- The resource agencies are likely to require that TransCanada upgrade its track racks to protect aquatic life and biota by reducing fish entrainment or impingement.
- The resource agencies are likely to require that TransCanada improve fish passage upstream and downstream of the facilities by maintaining and operating fish ladders to provide safe, timely and effective passage of fish species.
- The resource agencies are requesting an additional year of study regarding eel passage at the three facilities. If current operations interrupt eel passage, the resource agencies are likely to require a habitat conservation plan or operational changes that minimizes and mitigates harm to the impacted species during operations.
- The resources agencies may require a recreation management plan. Recreation is a use under the Vermont Water Quality Standards that must be protected and maintained. Most recreational uses are supported by minimum flows necessary to support aquatic life and habitat, so ANR typically focuses on ensuring that the aquatic life and habitat use is supported and the aquatic life and habitat criteria are achieved. However, ANR does often include recreation conditions in its 401 certifications that are separate and apart from the conditions required to support aquatic life and habitat. For example, at Waterbury Dam, ANR required that the licensee develop a recreation management plan.

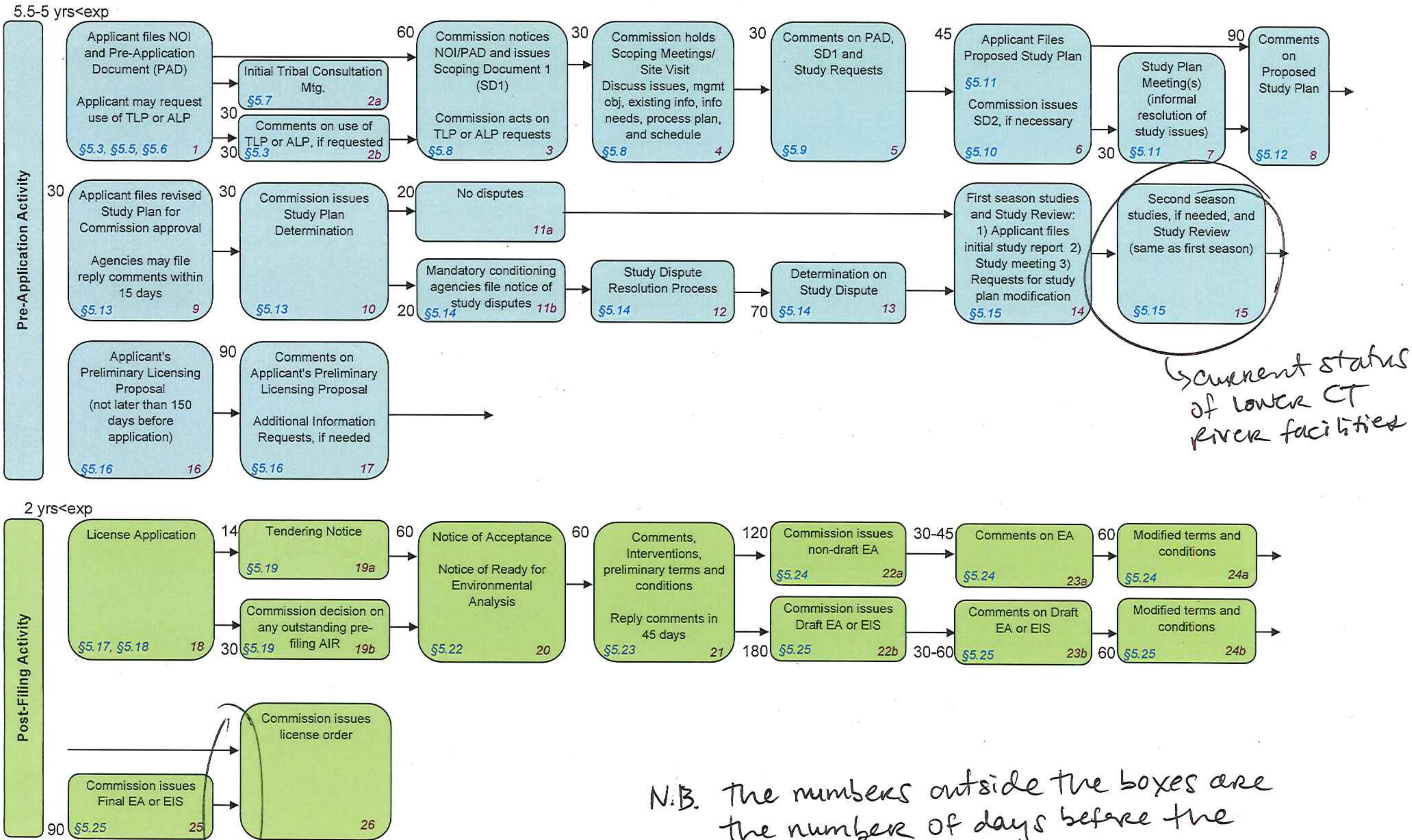
6. Expected Changes Due to Relicensing

Although it is impossible to provide clear estimates of how much the relicensing process will reduce generation capacity or revenue, it is almost certain that some loss of revenue will occur. As explained above, TransCanada has not yet submitted a preliminary application to FERC or even completed all environmental studies necessary for the resource agencies to commence environmental review. Once the reports are received, it could take over a year for the resource agencies to complete their review and there is always the possibility that the resource agencies will request additional studies. Even once Vermont has reviewed these materials and determined the necessary conditions, it is possible that New Hampshire or USFWS may require additional conditions beyond those required by Vermont.

The recent relicensing processes undergone in Vermont serve as examples that older hydroelectric facilities must undertake significant operational changes in order to comply with modern environmental law. Based on these recent relicensing processes, peaking will likely be reduced or eliminated and operations that are more consistent with run-of-river are likely to be required, which will have a significant impact on the amount of electricity generated. In addition, these requirements may force the facilities to make structural and technological upgrades. Revenue may also decrease as a result of timing restrictions. Timing restrictions will not necessarily decrease generation, but will require that generation occur during non-peak hours, which will result in reduced revenue.

In light of the above-mentioned caveats provided and assumptions made, ANR recommends that the Vermont Hydropower Working Group anticipate that TransCanada's dams on the lower Connecticut River will see a reduction of up to thirty percent in revenue as a result of the relicensing process.

Integrated Licensing Process
Final Rule (18 CFR Part 5)



N.B. The numbers outside the boxes are the number of days before the next action occurs.

401 issued