



Feasibility Study - Transmission Lines Action Plan.



New Hampshire Office of Energy and Planning

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1. Executive Summary

1.1 Problem Description

Northern New Hampshire is rich in renewable energy resources. However, the existing transmission infrastructure in the region is not sufficient for integrating all of the proposed renewable generation projects. Transmission investments would be needed to interconnect resources, address ensuing reliability needs and ensure enough capacity so that generators have transmission access to deliver the full power they are capable of producing.¹

Investments to integrate proposed renewable energy projects in northern New Hampshire could cost many millions of dollars. Under existing regulations, the costs of upgrades to the local transmission system, known as the “Coos Loop”, would be the responsibility of generators wishing to interconnect.² Such integration costs vary by generator, depending on location and on the extent of prior upgrades made by other interconnecting parties. In some cases, the interconnection costs, in conjunction with other project risks that affect financing, may be too great to justify the investment. Larger transmission investments to integrate numerous renewable resources on a regional basis are also possible. However, under current rules, the costs for such investments must be borne by participants if the investments do not provide reliability or market efficiency benefits to New England, or are prompted solely by generator interconnection.

Coordination among the interested parties could facilitate commitments that could be made to reduce project risks and to clarify how investors would recover their costs. As such, in order to enable transmission developments that would integrate renewable resources in northern New Hampshire, a consensus agreement is needed on how to allocate transmission costs beyond the methods specified in existing regulations. This report lays out the framework for an action

¹ Limited capacity on the line could mean that though generators might interconnect, they all would not be able to generate simultaneously at full output without violating ISO-NE’s reliability rules. As such, designing the system for ‘full deliverability’ or the ability for all generators to generate simultaneously is important for generators to make sure they can sell 100% of their product.

² Existing regulations allow for certain transmission costs to be socialized across New England, where New England as a whole would realize reliability or market efficiency benefits from the upgrades. Upgrades to the Coos Loop would likely not qualify as reliability or market efficiency upgrades under present regulations.

plan to pay for an upgrade of the transmission system in northern New Hampshire, otherwise known as the North Country.³ It strongly recommends a cost allocation approach which entails a purchase power agreement between the State of New Hampshire and renewable energy developers to repay an up-front loan by the State. This study also identifies existing impediments to transmission development in northern New Hampshire, documents stakeholder concerns, and evaluates a series of cost allocation approaches used throughout the country.

1.2 Study Approach

In developing the framework of an action plan, consultants met with a number of stakeholders through private and public meetings and obtained information in the public record. Researchers obtained feedback from interested parties regarding potential cost allocation methodologies and the potential impact that transmission development and various cost allocation methods might have on stakeholders. As well as gathering input from stakeholders, researchers assessed whether cost allocation methodologies used throughout the U.S. would be applicable and beneficial to addressing transmission development barriers in the North Country. Researchers then proposed a subset of transmission cost allocation approaches and assessed the potential impact of these on stakeholders within New Hampshire. In completing the study, researchers developed a framework of an action plan, outlining implementation steps and recommending responsible parties. As requested by the study sponsors, the framework was based on the assumption that the transmission upgrades to integrate an additional 400 megawatts (MW) of new generation on the Coos Loop would cost \$150 million. As a sensitivity, researchers examined how the recommended cost allocation framework might change if upgrades were ten or twenty percent above or below this amount.

The following highlights the steps taken to develop the framework of an action plan to pay for a transmission system upgrade in New Hampshire's North Country:

1. **Meet with Stakeholders.** This entailed holding public and private meeting with a variety of interested parties to gather input.

³ Recommendations in this study may need to be tailored to meet both energy conservation or generation and historic preservation goals, or may need to be tailored if a project is using federal funding. Recommendations made in this Feasibility Study, if and when implemented, may require review by the New Hampshire State Historic Preservation Office.

2. **Recommend cost allocation methodologies and a financial framework appropriate for the Coos Loop.** This team investigated how similar situations have been handled across the country and looking at Federal changes in legislation that may affect cost allocation. The team also reviewed the challenges and opportunities of transmission cost allocation and proposed a set of cost allocation solutions feasible for New Hampshire.
3. **Describe the potential cost impacts of various cost allocation methodologies.** The team reviewed existing financial studies and analyses and assessed the impact of cost allocation methodologies on New Hampshire electricity customers, renewable energy generators and other parties.
4. **Develop the framework of an action plan.** The report identifies high-potential cost allocation solutions and defines the steps to be taken to implement those solutions.

1.3 Findings

Under existing New England rules, socializing transmission investment costs across ratepayers is permissible only when the investment benefits the regional electric grid's reliability or enhances market efficiency. In addition, the ISO New England, Inc., Transmission, Markets and Services Tariff ("ISO-NE Tariff") requires that all costs required for interconnecting a generator, including any necessary system upgrades, be paid for solely by the generator.⁴ Given the nature of the Coos Loop, that is its limited interconnection with the New England electric grid, it is unlikely that upgrades to the existing system would result in regional reliability or market efficiency benefits, and thus would not qualify for regional rate recovery. Reliability upgrades required to serve local area load would be socialized across the entire Northeast Utilities system per its local tariff. New generator related upgrades cannot be socialized per the ISO-NE Tariff. Even if the existing Coos Loop was considered a regional facility (PTF), the ISO-NE Tariff would require that the costs be paid for by the connecting generators. Therefore, transmission investments to upgrade the Coos Loop in order to accommodate additional generation would need to be allocated outside of the ISONE Tariff rules through independent agreement(s), if the current methodology was not acceptable. Alternatively, the ISO-NE Tariff would need to be modified. In general, changes to the ISO-NE tariff are the result of a comprehensive

⁴ See ISO-NE Tariff at Section II (the "ISO-NE Open Access Transmission Tariff" or "ISO OATT"), Schedules 22 ("Large Generator Interconnection Procedures" or "LGIP") and 23 ("Small Generator Interconnection Procedures" or "SGIP").

stakeholder process in which consensus is sought and which includes the active participation of the six state utility commissions as well as generators, transmission owners, end users and others who make up the participants in the New England Power Pool, and the approval of FERC. In the near term, innovative options that allocate costs among the interested parties are more feasible, and approaches that allocate these costs to direct beneficiaries are most likely to succeed.

This study recommends an approach whereby the risks to generator and transmission developers would be reduced by State actions that provide:

1. up-front commitments to purchase power, and
2. either up-front funding or low-cost debt to help finance development costs.

Under such a scenario, the State would recoup its near term investments over time through a purchase power agreement to purchase electricity generated by the renewable developers and sold to the State at a cost less than the current generation component of the retail rate.⁵ This approach would avoid increasing electricity rates for any ratepayers in the State. It would also provide a mechanism for the State to support its policy goal of developing renewable resources in the State and procuring renewable energy.⁶ Where renewable generators would not be able to sell at a price below retail rates, the State could consider providing additional financial support by negotiating a price above retail rates or provide up-front subsidies to support project development.

The Federal Energy Regulatory Commission (FERC), the federal regulator of interstate transmission services, appears to be generally supportive of innovative cost allocation approaches that are reasonable and just. The research team believes that this approach would be supported by FERC and the New England system operator.

⁵ The remainder of the retail rate does not vary with the electricity used. Paying generators up to the full retail rate would increase costs to retail customers.

⁶ According to a 2009 Energy Management Annual Report for State-Owned Buildings and Fleets, New Hampshire “is investigating more sustainable means of purchasing or generating heat and electricity in order to meet the state’s Renewable Portfolio Standard, and other renewable energy goals.” (New Hampshire State Energy Manager 2009) Towards this goal, the State contracted with ConEdison to provide wind power to the State from July 1 to May 31, 2010. (Office of the Governor 2009).

Currently, FERC is proposing to amend its rules regarding transmission cost allocation to 1) require that electric grid operators conduct a transmission planning on a regional basis and 2) incorporate various policy initiatives into this plan. FERC also is proposing rules to lower the barriers for construction of new transmission facilities by non-incumbents. However, these rule changes are unlikely to impact the Coos Loop situation because it does not require ISO-NE to change its cost allocation approach, which limits the socialization of transmission costs to reliability and market efficiency upgrades. By the end of September 2010, over 200 entities had submitted comments to FERC and additional comments will be taken in November 2010. Furthermore, implementation will not occur until 2011 or later.

Though region-wide planning is beyond the direct scope of this study, such planning is important as it could help to identify economically efficient ways to integrate larger quantities of renewable resources, and avoid incremental investments that can come at a higher cost per unit of capacity connected. There is a need, however, to balance such regionally optimized development with practical considerations to move forward quickly. In assessing the potential for regional solutions, it would be prudent to assess the total amount of developable renewable energy capacity that transmission development could support. A simple approach would be to provide a timeline over which interested parties could register their interest.

Apart from New Hampshire-based efforts to develop transmission connecting remote renewable resources in Coos County to the grid, regional transmission development efforts are also under way. In particular, certain New England transmission operators are currently investigating a voluntary, “beneficiary pays” approach to connect more than 1,000 MW of remote, new renewable generation in New England. To date, the transmission owners have had preliminary discussions with regulators and developers regarding this high-level transmission plan.

Several options within that plan are being considered, though there is not yet any formal proposal. As such, it is difficult to ascertain the initiative’s impact on New Hampshire or on efforts to upgrade transmission in the State’s North Country. Nevertheless, it appears highly probable that the regional effort, if consummated, could connect some or all of the renewable resources planned for northern New Hampshire. Therefore, depending on the regional initiative’s transmission design and on its ability to move forward, the regional project could affect the need to upgrade the Coos Loop to interconnect additional North Country renewable resources.

Where the regional initiative’s design affects upgrades in the North Country, it potentially also affects the State’s role in supporting transmission development in the North Country. In particular, in the beneficiary pays approach being considered under the regional initiative, the

purchasers of power, rather than the State or New Hampshire ratepayers, would ultimately pay for the transmission through a transmission service agreement associated with a purchase power agreement (PPA).⁷ In addition, where the regional initiative's design addresses the majority need of renewable developers in the North Country, it could potentially supersede the need to develop a cost allocation plan specific to transmission development in Northern New Hampshire alone. As such, the regional initiative currently underway potentially presents another option should the State be unwilling or unable to finance or subsidize transmission development in the North Country. However, the lack of deadlines associated with the regional initiative, and the uncertainty in the transmission design, means that there is a tradeoff between waiting to assess potential synergies between a regional transmission development solution versus moving forward now to control the timeline and design of transmission development in New Hampshire's North Country.

⁷ Specifically, if approved by FERC and states, Renewable Developers would be granted access to, and the purchasers of power would pay for, transmission service from the transmission providers in order to make a related transmission and renewable generation product available to load in southern New England. The entities that enter into PPAs with Renewable Developers would effectively fund the transmission and generation development. The transmission developer would recoup costs over time with load paying for the transmission costs of the project, and the generators would recoup generation investment costs through the PPA. Meanwhile, the existence of a PPA would facilitate generation financing. According to participants in the process, the project is intended to minimize costs by essentially routing transmission to the most cost effective renewable generation, thus minimizing generator interconnection cost and is intended to result in combined transmission and renewable generation product deliverable to loads in southern New England in a cost effective manner.

The figure below summarizes key findings from this study.

Key Findings

- Socializing localized transmission costs across all New England ratepayers is an unlikely prospect given both current New England rules and given the nature and design of the Coos Loop.
- Approaches which allocate costs to beneficiaries or which serve public policy purposes are more likely to succeed.
- This study recommends an approach that reduces developer risks through commitments by the State to purchase power and provide up-front financing or low-debt loans to help reduce developer risk. Repayment to the State would occur over time through reduced rates negotiated in advance with developers.
- Although the Federal Energy Regulatory Commission is currently considering changes to its transmission rules, it is unlikely that such amendments will have a direct near-term impact on the Coos County transmission development.
- Regional planning initiatives are currently underway. If successful, these initiatives could affect the need to upgrade the Coos Loop to interconnect additional North Country renewable resources.

2. Introduction

In 2008, the New Hampshire Legislature formed the North Country Transmission Commission (NCTC) and directed it to complete a study to develop an action plan that identifies potential methods for allocating transmission costs.⁸ To assist in that effort, the New Hampshire Office of Energy & Planning (OEP) and the NCTC have sponsored this study, paid for in its entirety by funding awarded through the American Recovery and Reinvestment Act of 2009 (ARRA).

This report summarizes stakeholder input about transmission development in northern New Hampshire, otherwise known as the North Country, evaluates several transmission cost allocation methodologies for their potential application in the North Country, and lays out a framework of an action plan to pay for transmission upgrades in the region. It is not intended to assess or develop potential transmission designs. Rather, it is intended to help guide stakeholders towards reaching a consensus decision on ways to allocate the cost of potential transmission development in the North Country.

The remainder of this section provides background on existing transmission in the North Country. Section 3 highlights stakeholder opinion about transmission development in the North Country and proposed transmission cost allocation methodologies. Section 4 outlines the basics of transmission cost allocation and provides examples of how other states and regions are approaching this issue. Section 5 evaluates the application to New Hampshire of several transmission cost allocation approaches. Section 6 assesses the impact that transmission costs and benefits might have on local stakeholders in northern New Hampshire. Section 7 lays out the framework for an action plan to pay for an upgrade of the transmission system in the North Country.

2.1 Project Background

Stimulating and facilitating the development of renewable energy resources is a regional priority for New England and a state priority for New Hampshire. Each of the New England states has implemented a number of programs to promote the development of renewable resources.⁹

⁸ Senate Bill 383, Chapter 348, Laws of New Hampshire, 2008.

⁹ According to the 2009 Governor's Blueprint Report: "Each of the New England states is seeking, through initiatives associated with various state laws, policies, and regional coordination, the aggressive

The State of New Hampshire currently promotes renewable energy development through mandated utility purchases of renewable energy under a renewable portfolio standard (RPS), as well as tax exemptions and incentives for wind, biomass and solar generators.¹⁰

The North Country, particularly Coos County, offers plentiful wind and wood fuel energy resources which have attracted the attention of generation developers. Currently, renewable energy developers have proposed over 400 MW of wind and biomass projects in the region. However, the existing transmission line in the region, known as the Coos Loop, cannot integrate all of these proposed projects without further investment. Such investments are necessary to reliably move power from renewable generators to load centers in the region.

In 2007, New Hampshire Governor John Lynch signed into law legislation that stated encouraging renewable energy development is in the public interest, and that:

“...existing transmission infrastructure, particularly in the northern part of the state, will need to be upgraded or replaced or new transmission facilities will need to be built.”¹¹

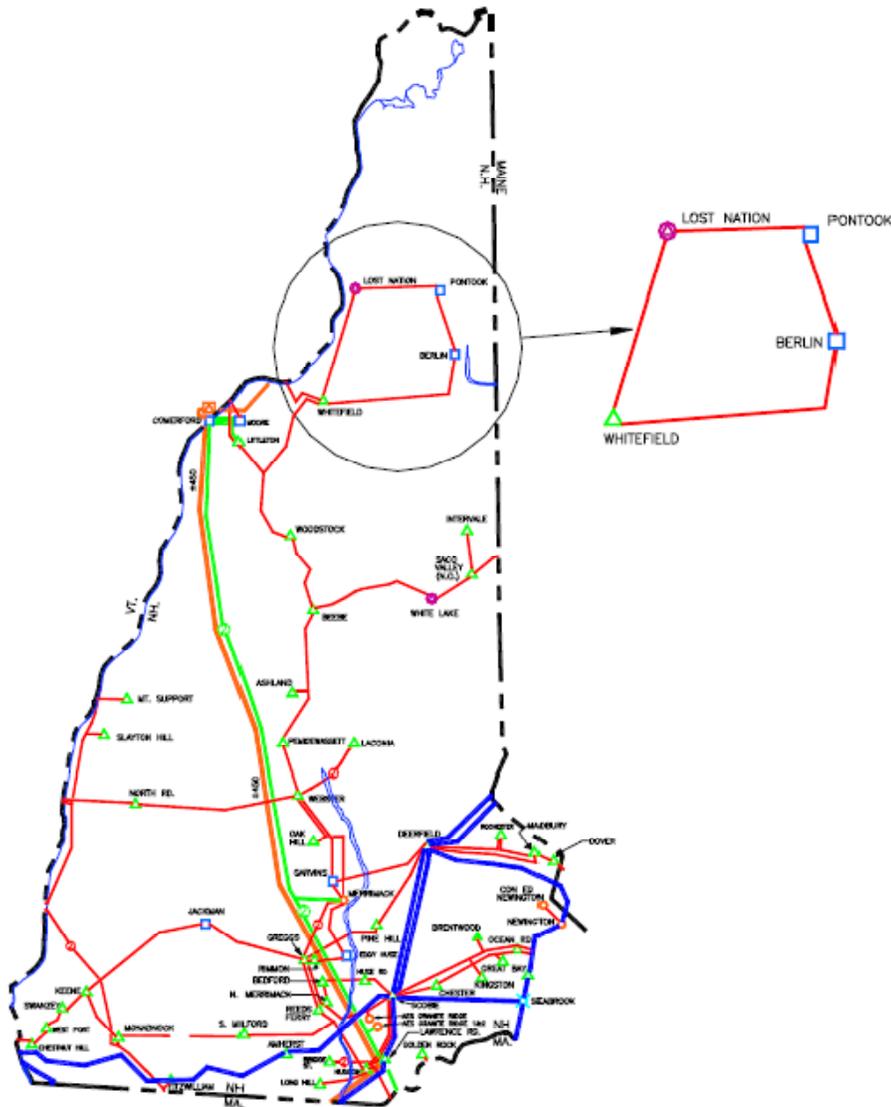
Existing transmission in Northern New Hampshire, including the Coos Loop, is owned by Public Service Company of New Hampshire (PSNH). The Coos Loop includes 115 kilovolt (kV) lines comprised of four segments that connect to the Whitefield substation owned by PSNH. This substation is connected to the Littleton and Woodstock substations owned by PSNH and the Moore substation owned by National Grid. The Coos Loop is located in the towns of Northumberland, Stark, Milan, Berlin, Gorham, Randolph, Whitefield, and Lancaster. Two additional towns, Kilkenny and Jefferson, are located inside this loop. Figure 1 displays the approximate boundaries of the Coos Loop, which connects the Whitefield, Berlin, and the Lost Nation Substations.

development of renewable resource potential within and outside state borders.” (The New England Governor’s Conference, Inc 2009, Page 6).

¹⁰ NCSC and IREC, *New Hampshire Incentives/Policies for Renewables & Efficiency*. 2010.

¹¹ New Hampshire Laws of 2007, Chapter 364:1.

Figure 1. Coos Loop Transmission Line, Coos County, New Hampshire



Source: PSNH 2008.

2.2 Problem Description

Having the ability of a generator to produce power when economically viable is the key to delivering power and is a primary factor in providing the certainty developers need to advance their projects. Other factors critical to financing include adequate market revenue to support the investment costs and ongoing fixed and variable costs. Developing transmission to interconnect potential renewable resources in the North Country could cost millions of dollars, and involve local, state, regional and national authorities.

Under the existing ISO-NE Tariff rules, transmission costs are socialized, or distributed region-wide, if projects meet stringent system reliability or market efficiency criteria and the facilities are classified as network facilities, or “Pooled Transmission Facilities” (PTF). As neither criterion likely applies, the proposed Coos County projects to date are all considered as being related to generation interconnections, and as such all necessary interconnection costs and related system upgrades to connect new generation must be borne by the generators. No specific transmission upgrade has yet been designed, as it depends on the amount and location of new renewable energy projects. However, PSNH has estimated that at least \$100 million could be required to connect 400 MW wind and biomass facilities to the Coos Loop.¹²

Historically, costs of transmission reliability projects have been allocated to and recovered from all ratepayers, while private generation project developers have paid to connect their facilities to the transmission grid. In the last decade, this model has come under review as states are seeking to remove economic barriers to encourage renewable development. Several renewable energy generators across the country, including Coos County, New Hampshire, have stated that the added cost of transmission upgrades can tip projects toward economic unfeasibility. States such as California, Texas, Oregon, Wyoming and many others have developed alternative approaches to creatively finance hundreds of millions of dollars in transmission upgrades needed to deliver power from generators to customers.

Various upgrades to the existing Coos Loop have been considered over a multi-year stakeholder process. However, thus far, no agreement has been reached on how the associated costs of upgrading the Coos Loop would be shared among parties. The issue of cost allocation so far has been an impediment to further transmission development in the region. To develop a workable solution, the New Hampshire Legislature mandated a study to develop an action plan and ways to allocate the proposed upgrade costs, and directed formation of the NCTC that brought stakeholders together.

¹² PSNH, *Northern New Hampshire New Resource Interconnection Options and Costs*. 2008.

3. Stakeholder Roles, Feedback and Concerns

Throughout the study, researchers met with a number of stakeholders to solicit feedback and ascertain stakeholder's views on the impact that transmission development and various cost allocation methods could potentially have on stakeholders. This chapter describes the roles of several stakeholders interested in transmission development in the North Country and summarizes input received either through meetings or in the public record. This summary is not intended to represent a complete list of stakeholders or their comments. Rather, it is intended to be representative of the types of parties involved and the opinions voiced. Minutes from the public meeting held for this study and NCTC meetings regarding this study will become available on the New Hampshire Public Utility Commission's website.

3.1 Stakeholders

A number of stakeholders with a diverse set of views have an interest in proposed transmission developments of the North Country. Stakeholders discussed here include State agencies and officials; representatives of the North Country; electric utility companies and transmission owners; transmission and generation developers; New England Independent System Operator (ISO-NE); and FERC.

3.1.1 North Country Transmission Commission

Created by the New Hampshire Legislature in 2008, the NCTC's purpose is to develop a plan for the expansion of the transmission capacity in the North Country.¹³ Members constitute a variety of stakeholders including legislative appointees as well as voting and non-voting members.¹⁴ The NCTC is administratively attached to the NHPUC.

¹³ Senate Bill 383, Chapter 348, Laws of New Hampshire, 2008.

¹⁴ Members of the NCTC include representatives from the State Senate and House of Representatives, New Hampshire Office of Energy and Planning, Energy Efficiency and Sustainable Energy Board, Public Utilities Commission, Governor's Office, North Country, Plymouth State University, Public Service of New Hampshire, National Grid Group, New England Power Generators Association, and organizations and associations associated with proposed renewable generation projects.

3.1.2 State Agencies and Officials

Office of the Governor. The New Hampshire Governor's Office has a long record of supporting energy efficiency and renewable energy development in the State. For example, in 2005, Governor John Lynch set a 10% reduction target for energy consumption in state buildings. Two entities oversee this effort, the State Energy Manager ensures that the Executive Order is fulfilled and the Department of Administrative Services (DAS) implements an energy information system to measure progress in meeting the 10% reduction target. OEP staff members support the State Energy Manager's efforts to collect and analyze data in State buildings. Currently, energy use per square foot in state owned buildings has decreased by 4% since 2005, although gross energy consumption in state-owned buildings has increased by 4%.¹⁵

In 2006, the Governor set a goal of having 25% of the state's energy requirements be met with renewable sources by 2025.¹⁶ In 2007, in close alignment with this goal, the Governor signed the Renewable Energy Act (HB 873) which sets a mandatory RPS for electricity providers.¹⁷ In 2009, to help meet New Hampshire's renewable energy goals, the State signed a \$4.4 million, 11-month electricity contract with ConEdison to purchase 25% of its energy from wind power.¹⁸ The electricity price is 9.2 cents / kWh for the generation component of the rate.¹⁹ Other charges such as transmission, distribution, and customer service charges are applied in addition to the generation component of the rate.

More recently, in 2010, Governor Lynch signed into law SB73, which sets a goal that the State government reduces fossil fuel energy consumption per square foot in state-owned buildings by

¹⁵ New Hampshire State Energy Manager. *State of New Hampshire Energy Management Annual Report for State-Owned Buildings and Fleets: Fiscal Year 2009*. 2009.

¹⁶ Accessible at: online at: http://www.nh.gov/oep/programs/25_x_25/index.htm. Accessed August 25, 2010. Energy requirements include transportation and heating energy and electricity generation.

¹⁷ New Hampshire Statutes, Chapter 362-F. The mandate requires electricity providers to obtain renewable energy certificates for 23.8% of the retail electric energy sold to end-use customers by 2025. Renewable energy certificates are records that identify each megawatt-hour generated by a renewable energy generating source under RSA 362-F:6. In 2008, amendments were enacted which exclude municipal suppliers from the requirements. (House Bill 295).

¹⁸ Accessible at: <http://www.governor.nh.gov/media/news/2009/070209.htm> Accessed August 25, 2010.

¹⁹ Estimated from contract dollar and energy amounts.

25 percent by 2025.²⁰ Provisions of the law include requiring State government to reduce energy consumption in State buildings, to develop an energy conservation plan, and to report annually on the state's consumption. Today, the State government spends almost \$22.5 million on energy costs at over 1,200 buildings.²¹

The Governor's Office is also engaged in regional energy efforts. New Hampshire Governor Lynch joined with five other New England governors to adopt the *Renewable Energy Blueprint* on Sept. 15, 2009.²² This Blueprint expedites development of New England renewable energy by coordinating reviews of interstate transmission line project proposals. The states also will work together to coordinate solicitations and decisions on procuring power and long-term energy contracts.

The New Hampshire Office of Energy and Planning (OEP). The OEP is part of the Executive Department within the Office of the Governor. The agency supports and promotes numerous energy efficiency, renewable energy and other sustainability programs in the State. As a state agency, OEP is coordinating New Hampshire's energy programs funded through ARRA. This includes coordination of a competitive bidding process, consultant selection and oversight, and administration of the state's ARRA-funded grants. OEP staff members serve on the NCTC and oversee the administration of the contract to conduct the study for this report.

New Hampshire Public Utilities Commission (NHPUC). The NHPUC is a regulatory entity that has jurisdiction over utilities engaged in providing electric, telecommunications, natural gas, water and sewer services in the state of New Hampshire and whose authority covers rates, quality of service, finance, accounting and safety. Its stated mission is "to ensure that customers of regulated utilities receive safe, adequate and reliable service at just and reasonable rates."²³ The NHPUC has three Commissioners who are appointed by the Governor and confirmed by the Executive Council to staggered six year terms. A Chairman acts as the overall agency head. NHPUC staff members serve on the NCTC. The NHPUC's authority includes transmission-related issues and NHPUC staff members have been engaged in

²⁰ Senate Bill 73, Chapter 328, Laws of New Hampshire, 2010.

²¹ New Hampshire State Energy Manager. *State of New Hampshire Energy Management Annual Report for State-Owned Buildings and Fleets: Fiscal Year 2009*. 2009.

²² The New England Governor's Conference, Inc., *2009 New England Governors' Renewable Energy Blueprint*. 2009.

²³ Accessible at: <http://www.puc.state.nh.us/Home/aboutus.htm>. Accessed August 25, 2010.

transmission development in northern New Hampshire throughout. Previous reports drafted by NHPUC staff have provided information on transmission infrastructure and development in the State and examined possible cost allocation approaches.²⁴

Office of Consumer Advocate (OCA). The OCA represents the residential ratepayers in the State of New Hampshire and advocates on their behalf in accordance with State law.²⁵ The OCA is focused on residential customers of regulated utilities. While administratively attached to the NHPUC, the OCA is an independent organization and often a party at NHPUC cases.

Site Evaluation Committee (SEC). The SEC was created by the legislature to determine whether to grant generators the right to build a bulk power supply facility or other energy facility at a specific site.²⁶ In evaluating the application, the SEC must determine whether:

- *“the applicant has adequate financial, technical and managerial capabilities;*
- *the facility will not unduly interfere with the orderly development of the region;*
- *the facility will not have an unreasonable adverse effect on aesthetics, historic sites, air and water quality, the natural environment, and public health and safety; and*
- *the facility is consistent with state energy policy.”²⁷*

For approval of transmission lines over which the NHPUC has jurisdiction, the NHPUC must also find that the facility is “required to meet the present and future need for electricity” and that it “will not adversely affect system stability and reliability factors.”²⁸ The Committee has fourteen members from a variety of State agencies.²⁹

²⁴ NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007; NHPUC, *Commission to Develop a Plan for the Expansion of Transmission Capacity in the North Country: Progress Report. Pursuant to SB 383 Chapter 348, Laws of N.H.* 2008.

²⁵ RSA 363:28.

²⁶ A bulk power supply facility includes generating facilities capable of operating at 30 MW or greater and electric transmission lines rated at 100 kV over new rights of way and which are either associated with a generating facility or more than 10 miles.

²⁷ NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007.

²⁸ Ibid.

²⁹ Agencies represented on the Committee include the Department of Environmental Services, the Public Utilities Commission, the Department of Resources and Economic Development, the Department of

Legislators. The New Hampshire General Court, New Hampshire's state legislature, consists of 400 members in the House of Representatives and 24 members in the Senate. In 2007, the General Court concluded that "[i]t is in the public interest and to the benefit of New Hampshire to encourage the development of renewable energy" and that "the existing infrastructure, particularly in the northern part of the state, will need to be upgraded or replaced or new transmission facilities will need to be built." (Laws of 2007, Chapter 364:1). Related to this finding, the General Court directed the NHPUC to enable and facilitate stakeholder discussions and to submit a report describing the transmission system and the process and any alternatives to complete transmission upgrades

In 2008, the General Court established the NCTC to develop a plan for expansion of transmission capacity in the North Country.³⁰ In 2009, the legislature extended the NCTC through Senate Bill 85, which also directed the NCTC to hire a consultant to develop "a framework for a proposal for the upgrade of the transmission system in the North Country" to file with the FERC.³¹ This governmental agency oversees the transmission system reliability and the charges for transmission services.

In 2009, the members of the Senate and House sponsored legislation that would have appropriated \$155,000,000 to the public utilities commission to administer "capital improvements to the Coos Loop and other related transmission infrastructure in northern New Hampshire."³² The funds would come from a variety of sources, including new generation developers, New Hampshire ratepayers through a transmission charge, state-issued bonds and federally-funded programs.³³ The legislation did not make it out of the Senate Committee on Energy, Environment and Economic Development.

Health and Human Services, the Fish and Game Department, the Office of Energy and Planning, the Department of Cultural Resources and the Department of Transportation.

³⁰ New Hampshire Senate Bill 383. <http://www.gencourt.state.nh.us/legislation/2008/SB0383.html>

³¹ New Hampshire Office of Energy & Planning, *Request for Proposals Transmission Line Action Plan*, January 27, 2010.

³² NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007; New Hampshire Senate Bill 164, 2009.

³³ When SB 164 was first drafted, it appeared that American Recovery and Reinvestment Act funding would be available for transmission investments in remote areas that were rich in renewable energy resources. The final version of the bill, however, deleted those provisions.

3.1.3 North Country Representatives

Economic Development Organizations. New Hampshire has a number of organizations throughout the State that support economic development within their communities or regions. These include Local Development Corporations, Regional Development Corporations, Certified Development Companies, and Industrial Development Corporations. These organizations support business development and economic growth within their communities and offer assistance through low-cost financing, among other services. The Coos Economic Development Corporation is part of a larger non-profit regional economic development corporation that serves the State of New Hampshire, and is a conduit for the U.S. Department of Housing and Urban Development community development block grants. In addition, the North Country Council is an Economic Development District as appointed by the U.S. Department of Commerce's Economic Development Administration. It covers 67 communities and 25 unincorporated places in New Hampshire.

Coos County Commission. The Coos County Commission consists of three Commissioners, Chair, Vice Chair and Clerk. The Commission serves as the executive branch of the County Government, and addresses fiscal and policy matters in the region. Coos County is one of ten counties in New Hampshire. Incorporated in 1803, Coos County has a population of about 33,000 people, and covers a land area of over 1,800 square miles, nearly 20% of the total land area of the State.³⁴

The General Public. Members of the public, including organizations and individuals residing or working in the State, provided input about the proposed developments in the North Country. Organizations included those serving the interests of the general public and local communities. The Coos Community Benefits Alliance (CCBA) is one such group. It is a group of like-minded organizations whose mission is to "ensure that energy projects in the Coos County region result in long-term, tangible benefits for local communities and our natural resource base."³⁵ Members include individuals from the New Hampshire Charitable Foundation, Bethel Local Energy Committee, Colebrook District Heating Committee, Tri-County Community Action Program, and the Northern Forest Center.

³⁴ Accessible at: <http://www.cooscountynh.us> and <http://quickfacts.census.gov/qfd/states/33000.html>. Accessed August 25, 2010.

³⁵ Coos Community Benefits Alliance, *CCBA Framing Document*. 2010.

3.1.4 Electric Utility Companies and Transmission Owners

Public Service Company of New Hampshire (PSNH). PSNH is the largest electric utility in the State, serving over 490,000 customers. (See PSNH's service area shown in Figure 2.) It is a wholly-owned subsidiary of Northeast Utilities, a utility holding company based in Connecticut. PSNH owns nine hydroelectric facilities, three fossil fuel-fired power plants which jointly constitute 1,110 MW of generating capacity. One of PSNH's fossil-fueled power plants also uses biomass as an input fuel. PSNH owns and operates approximately 1,000 circuit miles of high voltage transmission: 252 circuit miles at 345 kV, 743 circuit miles at 115 kV, and 8 circuit miles at 230 kV. This transmission system sends power through 56 substations across the State.³⁶

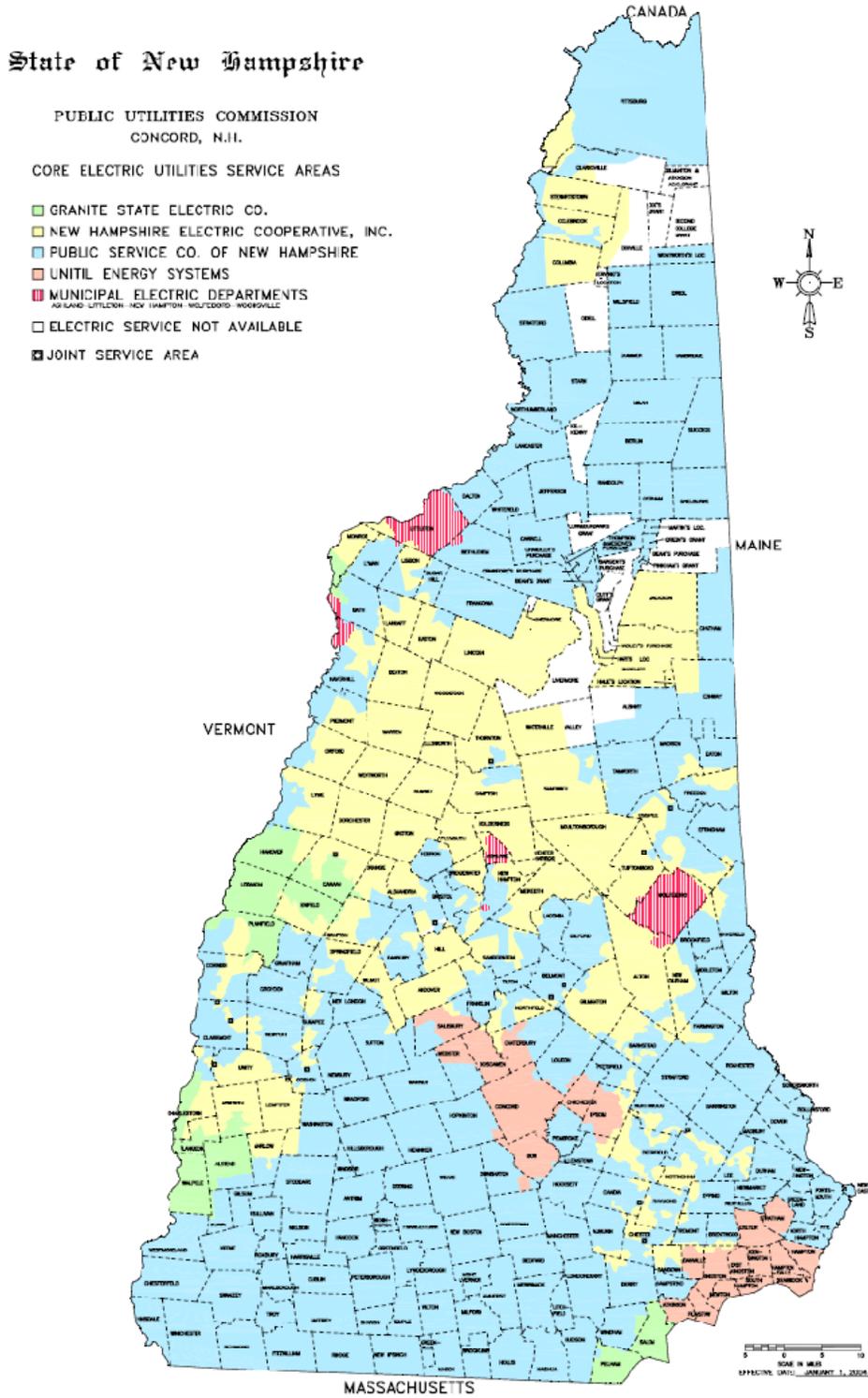
National Grid (NGRID). NGRID is the other major transmission owning utility in New Hampshire. It serves over 38,000 customers. The utility owns and operates over 300 circuit-miles of transmission in New Hampshire. The majority of these transmission facilities, over 82%, are 230 kV lines, nearly 17% are 115 kV and less than 1% are 69kV. The 230 kV lines export power from the Comerford and Moore hydroelectric facilities on the Connecticut River to southern New England. The 115 kV lines supply local area loads.³⁷

Anbaric Transmission. Anbaric Transmission develops, builds and owns independent transmission lines in the northeastern U.S. To date, it is the only non-utility entity that can develop transmission projects funded by ratepayers in New Hampshire. While Anbaric Transmission is an active stakeholder, to date no proposals have been submitted for private transmission in New Hampshire's North Country. The company has developed other transmission projects in the northeastern U.S. and is continuing to develop proposals.

³⁶ NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007.

³⁷ Ibid.

Figure 2. Electric Utility Service Areas



3.1.5 ISO-NE

The Independent System Operator (ISO) of New England is a FERC-approved regional transmission organization (RTO) with operational control over transmission facilities throughout the six New England states, including New Hampshire. Rates, terms and conditions of transmission service in New England are set forth in the ISO-NE Tariff.³⁸ Rates and charges are regulated by FERC, and are subject to modification. Modifications may be made through a rate change filing by ISO-NE or a local transmission owner, as appropriate. Alternatively, a complaint filed at the FERC showing that existing rates, terms and conditions of service are unjust, unreasonable, or unduly discriminatory may result in a modification.

The ISO- Tariff allows for different cost allocations depending on whether a transmission facility is deemed a pool transmission facility (PTF) or a local transmission facility (LTF).

- **Pool Transmission Facilities (PTF).** Generally, PTFs are transmission facilities that operate at 69 kV or above and that help to integrate region-wide electric system. The costs of PTFs are socialized and shared by transmission customers, network load, throughout New England. Network load pays for “Regional Network Service,” which is the revenue requirement for Pool Transmission Facilities. Generation that is connected to PTF does not pay for transmission service.
- **Local Transmission Facilities (LTF).** LTF are transmission facilities that operate at lower voltages and generally function either as generation leads to deliver electricity from generation facilities to the grid, or to deliver electricity from the grid to serve local loads. The costs of LTF are paid by transmission customers of the local transmission owner, which are both load and generation resources utilizing these non-PTF facilities. Where a generation resource utilizes Non-PTF facilities to access PTF facilities to transmit generation, it pays for Local Transmission Facility use pursuant to Schedule 21 of the ISO-NE Tariff.

3.1.5.1 Interconnection

Each generation interconnection project is unique and therefore, the administrative and technical studies (of feasibility, system impact, and facilities) necessary to determine the system

³⁸ ISO-New England, *ISO New England Transmission Market, and Services Tariff*. Retrieved from: <http://www.iso-ne.com/regulatory/tariff>

modifications required to ensure reliability must be conducted on a case-by-case basis. Throughout the process, ISO-NE must remain impartial while it administers the interconnection and facilitates communication between stakeholders. Each interconnection request is placed in a publicly available queue at the time the application is received. Where there may be an overlap in the impact of generators, the one that is filed first, and hence has a higher queue position, is given first rights to use the existing transmission. As of the October 2010 ISO-NE generator interconnection queue were approximately 100 proposed projects including approximately 230 MW of renewable projects in Coos County.³⁹

Generator interconnections in New England are completed according to the FERC-approved interconnection standards. The most basic test is intended to promote access to the transmission system, but does not guarantee full deliverability of a generator's output. Additional tests can be requested which would gauge deliverability. To determine if a unit can qualify for capacity credit, a separate study needs to be done. The Generator Interconnection Process (GIP) guides how, and under what conditions, new power plants are physically connected to the existing transmission system.⁴⁰ The Large Generator Interconnection Agreement (LGIA) applies to generators larger than 20 MW, and the Small Generator Interconnection Agreement (SGIA) applies to smaller generators.⁴¹ In terms of jurisdiction, the Coos Loop is FERC jurisdictional transmission, as would be any likely upgrades.

Under ISO-NE's competitive wholesale electricity market structure, developers of generator projects are responsible for the costs of interconnection studies and any transmission upgrades that ISO-NE determines are necessary to allow a project to interconnect to the grid.

³⁹ The ISO-NE generator interconnection queue is dynamic with projects continually entering and exiting for a number of reasons. Accordingly, the ISO-NE updates and posts the queue monthly to its website at http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html.

⁴⁰ Ibid.

⁴¹ Accessible at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06R&re=1&ee=1 [why not cite to the tariff?]

3.1.5.2 System Planning

Every year, ISO-NE works with transmission owners (TOs) in the region to develop a Regional System Plan (RSP).⁴² The annual RSP assesses system needs and identifies transmission upgrades that would have regional benefits. Specifically, the RSP provides 10-year forecasts of consumption and peak demand, documents the adequacy of the region's bulk power system infrastructure, and reports on the ability of the region to comply with key policies such as the renewable portfolio standard. As part of the RSP process, ISO-NE reviews the reliability of designs proposed by TOs and reviews their transmission cost allocations to determine which costs should be regionalized versus localized.

There are several phases to the yearly process for transmission development. It begins with the identification of system needs, either in terms of generation or reliability, through various assessments. New England stakeholders then provide input to the RSP through the Planning Advisory Committee (PAC). The regional system planning process is open and iterative and culminates with an open meeting where the public can provide input to ISO's Board of Directors before the ISO approves the RSP. While the RSP seeks to address system needs with market responses, such as demand-side measures or merchant transmission, the RSP does not constitute an integrated resource plan. Regional cost sharing applies to transmission projects that benefit the entire region.

The RSP process has resulted in numerous transmission investments to maintain reliability, with \$4 billion worth of investment going into service since 2002 and about \$5 billion worth of further transmission projects planned.

3.1.6 Transmission and Generation Developers

A core group of stakeholders that develop wind and biomass generation and transmission have expressed an interest to build in the Coos County region if sufficient transmission capacity can be secured in a way that does not impair the economics of their projects. Several stakeholders have an economic interest in the Coos Loop upgrade to interconnect their proposed generation, while some stakeholders have expressed interest in developing the transmission upgrade if economically viable. While other generation and transmission firms may have interests in such

⁴² The Existing ISO New England Regional System Planning Process is described in Attachment K to the ISO New England Transmission, Markets and Services Tariff.

upgrades, the following firms have attended public meetings, participated in the NCTC and some have commenced project development in the North Country, as noted.

Laidlaw Energy Group (Laidlaw). Laidlaw, founded in 2002, develops, acquires, and converts existing generation facilities to biomass and solar energy facilities. Under its affiliates, the company acquires fossil fuel and idled plants, as well as idled pulp and paper mills, in the northeastern U.S. Affiliate Laidlaw Berlin BioPower, LLC acquired the Berlin-based former Fraser Paper Mill in 2008 and plans to convert and upgrade it to a wood-fired biomass facility of up to 70 MW. This plant will deliver hot water to a Gorham, N.H. paper mill, and electricity to PSNH under a long-term Power Purchase Agreement (PPA).⁴³ Laidlaw, based in New York, New York, is a publicly traded company (OTC: LLEG.PK) since 2002.⁴⁴

Clean Power Development (CPD). CPD develops wood-fired biomass facilities across the U.S. in connection with partner Gestamp Biomass, a division of Gestamp Renewables. Existing projects under development include a 29 MW biomass combined heat and power plant in Berlin, NH, expected to start construction in the fall of 2010, and a biomass power plant in Winchester, NH.⁴⁵

Noble Environmental Power (Noble). Noble, founded in 2004, is a private renewable energy generating company with a 726 MW generation portfolio and approximately 1,800 MW of windparks under development throughout the U.S.⁴⁶ Noble is majority-owned by JPMorgan Partners Fund, which is managed by CCMP Capital. The firm's Granite Reliable Wind Park, a 99 MW, 33-turbine wind farm, is currently under development. This farm is located in four Unincorporated Places — Dixville, Millsfield, Irvings Location, and Odell — as well as in the town of Dummer, all of which are in Coos County. This wind farm has signed agreements to sell more than half the wind power output. The project received a U.S. Army Corps of Engineer permit to go forward in June 2010.

Wagner Forest Management (Wagner Forest). Wagner Forest, headquartered in Lyme, employs more than 70 individuals, including roughly 40 foresters, and manages 2.7 million

⁴³ Accessible at: <http://www.laidlawenergy.com/berlin-nh-project.html>. Accessed September 28, 2010.

⁴⁴ Accessible at: <http://www.laidlawenergy.com/investors.html>

⁴⁵ Accessible at: <http://www.cleanpowerdevelopment.us/projects.php>

⁴⁶ Accessible at: <http://www.noblepower.com/about-us/index.html>

acres in the northeastern U.S. and eastern Canada. The firm has proposed a \$500 million, 200 MW wind power park in Dixville, New Hampshire.⁴⁷

3.1.7 Federal Energy Regulatory Commission (FERC)

Transmission of electric energy in interstate commerce is regulated by FERC. By law, FERC is authorized to regulate the transmission and wholesale sales of electricity, and is charged with ensuring that rates, terms and conditions for wholesale sales and transmission of electricity in interstate commerce are just and reasonable and not unduly discriminatory or preferential. As such, FERC has authority over tariffs which allocate transmission costs among ratepayers in the region.

In 1996, FERC issued its Order No. 888, which requires all transmission owners to provide transmission service to all eligible customers on a non-discriminatory basis pursuant to a tariff on file at the FERC. In 1999, FERC issued its Order No. 2000, which encouraged utilities to transfer operational control over their transmission facilities to an independent RTO or ISO, which would provide transmission service on a region-wide basis.

Today, FERC has approved a number of tariffs which encompass a number of transmission cost allocation approaches. Section 4 provides a summary of some of these approaches. Generally, FERC is open to innovative transmission cost allocation, to the extent that it is just and reasonable.

On June 17, 2010, FERC issued a notice of proposed rulemaking (NOPR).⁴⁸ In the NOPR, FERC makes a preliminary finding that some existing methods for allocating the costs of new transmission may not be just and reasonable because they may inhibit the development of efficient, cost-effective transmission facilities necessary to produce just and reasonable rates. As such, FERC proposes transmission planning reforms, including a requirement that each transmission provider participate in a regional transmission planning process that produces a regional transmission plan. Information about ISO-NE's planning process is summarized in Section 3.1.5.

⁴⁷ Accessible at: <http://www.wagnerforest.com>

⁴⁸ FERC Docket Number RM10-23-000: Transmission Planning and Cost Allocation. June 17, 2010.

In its recent NOPR, FERC considers new rules that would address transmission development related to public policy initiatives. In particular, in addition to evaluating proposed transmission enhancements based on considerations of reliability and overall cost reduction, transmission providers would be required to consider transmission projects proposed to facilitate compliance with public policy requirements established by state or federal laws or regulations, such as RPSs. Transmission providers are to identify specific public policy requirements established by state or federal laws or regulations to be considered in the transmission planning process after consultation with transmission customers and other stakeholders. Transmission providers may also provide for consideration in the transmission planning process additional public policy objectives that are not specifically required by state or federal laws.

The proposed rule would eliminate provisions in existing tariffs that offer a right of first refusal for incumbent transmission providers to construct new transmission projects identified in transmission plans. The intent is to allow non-incumbents an equal opportunity to participate in regional transmission planning and development. The rule would not apply to merchant transmission lines, where costs are not recovered through a regional cost allocation.

In addition, the rule would require transmission providers to adopt a method to allocate transmission costs associated with projects related to the transmission plan. The intent of the NOPR as a whole is to align transmission planning and cost allocation procedures. The rule would have separate cost allocation methods to be developed for allocating intraregional transmission costs and interregional transmission costs. Furthermore, the rule notes that different cost allocation methods may be adopted for allocating the costs of:

- Facilities driven by needs associated with maintaining reliability and sharing reserves.
- Facilities being built to relieve transmission congestion and achieve production cost savings.
- Facilities being built to achieve public policy requirements established by state or federal laws.

The rules proposed by the FERC in its NOPR, if enacted, may not have a significant impact on timely enhancement of the Coos Loop to support development of renewable energy resources. ISO-NE has an open and transparent transmission planning process for evaluation of transmission system needs based on considerations of reliability and market efficiency in which interested stakeholders may participate. The proposed rule would simply require ISO-NE and the Participating Transmission Owners to amend their transmission planning processes to provide explicitly for consideration of public policy requirements established by state or federal laws or regulations that drive transmission needs, along with other factors already considered in

the transmission planning process. However, it would not necessarily affect the result of the transmission planning processes. Furthermore, the proposed rule will not necessarily require ISO-NE to change its cost allocation approach, which limits the socialization of transmission costs to reliability and market efficiency upgrades.

The proposed rule also would permit each transmission provider to adopt special procedures for allocation of the costs of transmission facilities that are planned for achieving public policy requirements established by state or federal laws or regulations. Unless they are properly designed, procedures used solely for allocation of costs of transmission facilities that are planned for achieving public policy requirements established by state or federal laws or regulations may fail to stimulate development of such facilities.

In any event, implementation of any final rule that results from the NOPR is likely to be far into the future. A final rule may not be issued until late winter or early spring 2011, and proposals to modify existing Open Access Transmission Tariffs to comply with the final rule would not be due until six months after the rule becomes effective. After such compliance filings are submitted, additional time (perhaps several months) will be required for the FERC to evaluate the compliance filings. Only then will transmission system operators, such as ISO-NE, begin to implement the tariff revisions by giving explicit consideration to proposals for construction of new transmission facilities in order to achieve public policy requirements.

3.2 Stakeholder Input

Researchers gathered input from a variety of stakeholders, either directly or through public record. This subsection distills these comments into a set of common issues, several of which underscore the existing impediments to transmission development in the North Country, the potential benefits and costs of transmission development and cost allocation approaches, and the role of transmission development in addressing State energy goals. Due to stakeholder confidentiality, names and identifying details of individual stakeholders have been withheld and many statements have been aggregated. The views expressed here are not those of KEMA or the NCTC as a whole. Rather, they are the opinions of stakeholders as identified through a series of stakeholder meetings held for the purpose of this study.

3.2.1 Perceived Project Barriers

Several stakeholders commented on barriers to transmission and renewable energy development. According to stakeholders, factors that create risks can impede projects by making financing more expensive and thus increasing project costs. Low risk and good credit

are key to good financing. In turn, stakeholders cited revenue certainty as a factor in successful projects. Overall, stakeholders commented that, in addition to the total cost of a project, the level of risk and who bears the risk are significant factors in determining whether a project can move forward.

Transmission Customers. According to stakeholder comment, to justify an investment, transmission developers need to identify how they are going to recover their investment costs and who they will recover them from. In short, they must identify who is going to pay them to develop a transmission line and how they will get paid for it. In addition, stakeholders noted that because transmission development can often involve significant capital expenditures and the processes towards full development can be lengthy, reliable commitments from these customers are key to justifying investments.

According to stakeholders, renewable power generators are potential customers for transmission developers. However, stakeholders also noted that there are risks to developing transmission facilities before it is clear that renewable energy projects could go forward. Specifically, stakeholders noted the potential for stranded costs where a line cannot be fully subscribed. Furthermore, stakeholders noted that overall project risk can increase where multiple developers are needed to fully subscribe a line. This is particularly true, one stakeholder noted, where multiple renewable energy developers might be subject to a common risk such as similar environmental permitting risks or financial risks. As such, transmission planners and owners may be reluctant to build transmission unless firm demand exists for line capacity, and unless they can create reliable commitments for the transmission services.

Transmission Certainty. With regard to renewable developer needs, stakeholders commented that renewable developers are more likely to commit to building power plants where they know transmission capacity will be available. In particular, knowing that transmission will be available helps increase certainty that generators will have a way to get their product to market.⁴⁹ In addition, having readily-accessible transmission available can lower overall project costs, with less investment in transmission required to sell power. The problem of accessing transmission

⁴⁹ Under ISO-NE rules for reliability review, the ISO-NE must affirm that a generator will not decrease the reliability of the electricity grid. However, the review does not account for whether a generator will have firm transmission rights to sell either energy or capacity in the market. Separate analysis must be done to determine this.

varies by developer, depending on location and reliability upgrade requirements. According to some stakeholders, there is a small subset of renewable energy projects with respect to which smaller investments are sufficient for them to access transmission capacity on the existing Coos Loop.

The reluctance of renewable energy developers to invest in power plants until transmission developers invest in transmission, and vice versa, can create a “chicken-and-egg” impediment that stalls the transmission development process. Put in another way, according to stakeholders, transmission developers must have a minimum density of power projects to justify development of a transmission line. However, without firm commitments to build the line, there will not be a density of renewable projects.

Credit-Worthy Partners. According to stakeholders, a number of different structures can work to pay off an investment over time. However, the debt and equity must come up front. According to stakeholders, a credit-worthy partner can also serve as a financial backstop, lowering the cost of credit. Stakeholders commented that many renewable energy developers do not have the type of credit available to help them to serve as a financial backstop on projects. In addition, stakeholders noted that financing barriers can be particularly pronounced among smaller, private firms. Since the economic crisis began in 2008, access to capital and credit has tightened and may delay or derail proposed generation. Stakeholders commented that public entities can be good partners in development as they have access to good credit. Furthermore, stakeholders noted that long-term agreements (on the order of 15 to 20 years) can help establish good credit. According to stakeholders, the longer the contract is, the lower the rate can be because of the reduced risk.

Cost of Transmission for Generation Projects. In theory, according to stakeholders, under a market-based system, demand for energy and renewable energy certificates (RECs), certificates representing generation from renewable energy, should drive investment to build and fund generation and to upgrade transmission where it is needed and economically viable. However, stakeholders noted that many smaller renewable projects may become uneconomic when faced with high transmission upgrade costs. Furthermore, stakeholders noted how other regions in the U.S. are promoting renewable energy in addition to the RECs trading programs.

Potential Ways to Address Risk. Stakeholders also mentioned potential solutions to help mitigate risk. One stakeholder noted an approach used in California, where new generation

projects pay down the transmission cost over time as they come online.⁵⁰ Stakeholders also suggested contracting with a State-sanctioned authority for firm transmission rights across a line in return for payment through a fixed tariff at a negotiated rate. The entity would provide revenue certainty in exchange for the capability to import power. An authority could enter into a long-term contract for development of a transmission line for a capacity equal to available resources in the area. The authority would own capacity on the line and take the upfront risk, but have the credit of the State behind it. The authority could then sell capacity to developers in return for payment.

3.2.2 Perceived Benefits and Costs to the North Country and New Hampshire

Several stakeholders commented on the potential benefits and costs of transmission development in the North Country and of cost allocation approaches. The following highlights the perceived benefits and costs and summarizes additional concerns and comments received.

Perceived Benefits. With regard to impacts to the North Country, the following benefits were cited by stakeholders:

- Local job stimulation: Several stakeholders pointed to a potential increase in jobs for the North Country due to the development of renewable energy resources in the area.
- Tax payments: Stakeholders acknowledged that potential tax payments or payments made in lieu of taxes, where taxes were not required, would contribute to the local economy.
- Increased fuel independence: Some stakeholders commented that by enabling renewable energy developments which rely on local resources, the State will be decreasing its overall reliance on foreign sources of fuel.
- Achievement of state clean energy targets: Many stakeholders commented that transmission development initiatives would help facilitate the development of clean energy resources which in turn would help the State meet its clean energy goals.
- Use of Local resources to meet RPS goals: Some stakeholders noted that by enabling state-based renewable resources, it could help New Hampshire keep revenue obtained

⁵⁰ Additional detail regarding this approach is provided in Section 4.

from RECs in the state rather going out of the state to purchase RECs from non-New Hampshire sources.

- Cheaper power: Some stakeholders believed that by using local renewable resources in the community, they could lower electricity prices.

With regard to stakeholder comments about the achievement of state clean energy targets, because transmission development in the North Country would provide a mechanism to deliver local renewable energy power to regional loads, it could potentially promote the development of renewable resources in the area. However, other stakeholders noted that though the NH RPS is a state-level requirement, resources from outside of the state can be used to help meet the goal. (Similarly, NH-based resources can help other states in New England meet their RPS requirements). As such, the development of renewable resources within the State could help the State meet its RPS requirements, but additional resources outside of the State could also contribute towards this goal.

With regard to stakeholder comment about cheaper power, other stakeholders noted that electricity prices are determined by a number of factors. Furthermore, stakeholders noted that electricity bills include charges for generation, transmission and distribution, and other services. With regard to the generation component of electricity bills, an electricity provider within New Hampshire can supply power by either self-generating, purchase power directly from a generator, or purchasing power from the regional wholesale market. As such, local generation does not necessarily determine local prices.

Additional details on regional RPS requirements, state energy goals, renewable generation projects and economic development are available in Section 6.

Perceived Costs. The following costs were cited by stakeholders:

- Adverse Impact on Tourism. Some Stakeholders were concerned that transmission and generation development could result in potential environmental and aesthetic degradation, such as alteration of scenic vistas or increased traffic, which could in turn negatively impact tourism. Stakeholders commented that no master planning is in place for zoning communities in the North Country with regard to renewable energy projects.
- Adverse Impact on Property Values. Some stakeholders shared concerns that the same environmental and aesthetic impacts could also negatively impacts on property values.
- Extraction and Exportation of Resources. Many stakeholders voiced a concern that local resources would be used to generate power for export. Furthermore, some stakeholders

worried that these resources could be put to other uses which would have a more direct benefit for local residents.

In response to stakeholder comment regarding adverse Impacts on tourism and property values, separate stakeholders noted that master planning is in place in the North Country. In particular, one stakeholder noted that since 1988, the Coos County Planning Board has had in place a Master Plan with zoning, subdivision and other land use documents. Other stakeholders questioned the claims that renewable energy projects would impact tourism or property values at all.

With regard to stakeholder comments on the extraction and exportation of resources, separate stakeholders clarified that with regard to wind resources, little to no impact would be felt. In particular, one stakeholder noted that wind farms would not diminish the capacity of private land holdings to continue to provide traditional forest products. Additional details on renewable energy project financing and electricity prices in the State are available in Section 6.

Perceived Role in Economic Revitalization. Coos County has been experiencing economic decline over the past few years. Compared to the statewide average, the county has lower wages, higher unemployment, and a net population decrease. According to stakeholders, the decline in manufacturing, one of two major industries in the North Country, has accelerated as paper and pulp mills have closed in Groveton and Berlin. In addition, according to stakeholders, the region's other major industry, tourism, is not well suited to replace the number and quality of manufacturing jobs lost.

By some stakeholder estimates, the North Country has lost up to 2,900 jobs as result of the economic collapse and closure of pulp and paper mills and furniture manufacturers. According to several stakeholders, replacement industries are needed to remake the basis of the North Country's economy. While the renewable energy plants proposed and under development will create local demand for unskilled and skilled labor, according to stakeholders, the total number of jobs created does not compare. This is particularly true for wind farms, according to some. One stakeholder estimated that only six full time jobs would continue beyond the development and construction phase of wind projects. Other stakeholders highlight the direct and indirect jobs associated with the biomass and wind generation as reasons to support such development. Some stakeholders cited renewable energy development as an economic development strategy for the region and cited biomass projects as a strong potential for ways to turn local knowledge and resources into an asset for the region. Meanwhile, other stakeholders questioned whether

the state or the public could make other investments that would have a better impact for economic recovery.

According to many, to reverse the economic decline, Coos County needs to attract an array of high-quality, well-paying jobs. According to some, developing renewable energy projects is one way to boost the regional economy. Several stakeholders commented that Coos County has significant resources to support these projects: a strong manufacturing history, wind energy potential, logging byproduct supply, and large tracts of privately owned land to site the power generation facilities. In return, these renewable projects could bring economic development in jobs and tax revenue to support local communities.

Perceived Mismatch in Costs versus Benefits. A subset of stakeholders perceived a mismatch between the costs and benefits of the proposed upgrade to local ratepayers, businesses and residents in the North Country. Some stakeholders questioned why North Country stakeholders would bear the environmental and economic costs while most power generated appears to be destined for out of region and out of state consumption. Stakeholders noted that generators would invest hundreds of millions of dollars to develop power facilities but stakeholders perceived little local impact for that investment. In addition, stakeholders were concerned that because some potential non-financial costs of renewable and transmission development might be difficult to quantify, that they would not be given equal weight to other factors that were easy to quantify. Lower electricity rates, stakeholders commented, could help offset and balance the perceived costs borne by local stakeholders.

Stakeholders also voiced concerns that private developers would build renewable power generation in the North Country and the region will accrue little benefit. Such concerns included:

- Minimal long-term job creation, particularly in wind power generation.
- Lack of local hiring due in part to a need for training in non-biomass-based industries.
- Export of wealth from the region with the export of renewable power from the region.
- Accrual of wealth to investors from energy sales and RECs despite local costs.

Other cost concerns included pressure on resources (displacing ability to generate power locally and build other industries) and environmental degradation.

Ratepayer Funding. Several stakeholders of different types, voiced an opinion that clear benefits should accrue to the ratepayers should they be required to help pay for the development of transmission.

Transmission Siting. Public stakeholders requested town hearings or project scope for town(s) affected by proposed generation plants and transmission upgrades.

Perceived High Energy Prices. Some stakeholders noted that they believed North Country ratepayers pay high electricity prices, claiming that they pay some of the highest rates in the region. Stakeholders questioned whether the proposed generation projects would lower local electricity costs.

In general, electricity prices depend on a number of factors. In particular, electric bills are made up of multiple components, one of which is generation. The generation component is dependent on which provider a customer selects, and it can vary across the State. All customers in New Hampshire, however, are subject to the same calculation for the non-generation components of the electricity bill.

In New Hampshire, electric customers can choose their generation supplier. (If customers do not actively choose another supplier, then they are supplied by default service). Where customers are served by the same electricity supplier, all customers will pay the same rate. For example, PSNH customers across the state pay the same rate as the rate does not vary by region. Additional information on electricity prices in the State is available in Section 6.**Local Resource Development.** A subset of stakeholders voiced a desire to develop resources in the region for local consumption – i.e., community scale renewable energy development – which would not require significant transmission development. Stakeholders saw this as a potential way to keep the benefits of the renewable development local while minimizing transmission costs.

Perceptions of Biomass Fuel Availability. A range of estimates have been released by varying stakeholders on wood products available to proposed biomass generating facilities in Coos County. As the primary firing fuel for several proposed plants, the availability and price of biomass products is of great concern as this economic input can alter the anticipated viability and profitability of proposed generation. One developer engaged Innovative Natural Resources (INR) to conduct an independent assessment of the availability and price for its proposed Berlin-NH based biomass plant. INR reported that suitable wood products can currently support roughly 30 MW of generation at roughly \$32 per green ton, delivered.

3.2.3 Perceived Role in State Energy Goals

Stakeholders voiced a range of views on how the facilitation of North Country renewable generating resources would contribute to meeting State energy goals for renewable energy and fuel diversity.

Renewable Energy. Many stakeholders commented on the role of renewable energy in the North Country contributing towards State RPS goals which requires that 23.8% of retail electricity be produced from renewable resource by 2025. Currently, limited types of renewable resources qualify. In addition, other New England states have RPS goals for which New Hampshire resources may qualify.⁵¹ Table 1 shows the eligibility of various renewable energy generation types by state. In all cases, biomass and wind energy qualify.

Table 1. RPS Qualifying Sources, by State

	NH	CT	MA	ME	RI	VT
Small Hydro	yes	yes	yes	yes	yes	yes
Large Hydro						yes
Wind	yes	yes	yes	yes	yes	yes
Solar	yes	yes	yes	yes	yes	yes
Waste		yes		yes (w/ recycling op)		yes
Biomass	yes	yes	yes*	yes	yes	yes
Landfill Gas	yes	yes	yes	yes	yes	yes
Demand		yes (class 3)				yes
Ocean	yes	yes	yes	yes	yes	
Efficiency		yes (class 3)				yes

Source: New England States Committee on Electricity 2010.

* MA will conduct a stakeholder process to consider the results of a recently completed biomass study and to consider existing regulations.

Stakeholders questioned how likely it would be that New Hampshire laws might change existing rules to permit additional renewable resources to qualify. In addition, stakeholders questioned whether Canadian resources could qualify and whether they would saturate the market. In particular, Hydro Quebec is planning three major transmission lines into southern New England:

⁵¹ Accessible at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NH09R&re=1&ee=1.

Though the state RPSs are requirements for state retailers, the rules in many states allow retailers to purchase RECs which are derived from out of state. As such, the location of renewable energy generation is independent of the requirements.

Maine, New Hampshire and Vermont, totaling approximately 1,200 MW.⁵² Stakeholders questioned whether this source of energy would saturate the renewable energy market, either through oversupplying the demand for RECs or taking up transmission capacity. Some Stakeholders noted concern that, depending on what resources qualified, the State could effectively export the potential benefits of renewable development to non-New Hampshire entities while paying the cost of requirements to integrate renewable resources. Other stakeholders emphasized the importance of New Hampshire resources towards meeting regional RPS goals.

Fuel Diversity. Stakeholders noted the potential benefits of interconnecting a diverse set of in-state renewable resources. In particular, stakeholders noted a decreased dependence on foreign oil and gas as an indirect benefit of the transmission development. Fuel diversity, according to stakeholders, can mitigate electricity price increases by allowing markets to have multiple fuels to choose from. Fuel diversification is essential to enhance energy security, reliability, and energy independence, according to some, because it serves as an extra “line of defense” against shortages or interruptions in any one fuel source.

New Hampshire has no fossil fuel reserves in the State.⁵³ However, natural gas and oil are the primary fuels for more than 40% of the existing generating capacity.⁵⁴ In addition to natural gas and oil, other electricity fuel sources are used to generate power in the state, including nuclear fuel, coal, hydropower, and other renewable resources. Because electricity for the State can either be generated locally or purchased from surrounding states, renewable development within the region and not only the state, could potentially increase the fuel diversity of the electricity consumed by New Hampshire.

⁵² G. van Welie, *U. S.–Canada Clean Energy Dialogue Increasing Trade in Clean Electricity*. 2010.

⁵³ EIA, *State Energy Profiles: New Hampshire*, October 2010. Available online at:

http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=NH

⁵⁴ ISO-NE, *New Hampshire 2010 State Profile*, 2010.

4. Cost Allocation Methodologies

The basic principle underlying the allocation of transmission expansion costs is that the beneficiaries of the transmission development should pay. The central problem is identifying the beneficiaries and then allocating the costs fairly among these entities.

Most ISO/RTOs have provisions in place that determine how to allocate costs among entities, based on the nature of the transmission project. For example, some ISO/RTOs socialize costs for certain projects that provide reliability benefits or economic benefits for electricity customers, or ratepayers. For other types of projects, including private generator projects, the developer is required to bear all costs. More recently, some ISO/RTOs have introduced provisions that address projects that help move power from areas rich in renewable energy resources to load centers where the power is needed. In addition, some approaches directly address who bears the risk associated with a project, as well as who ultimately pays for the transmission. For example, one party might pay for transmission up front while another pays for it over time. Outside of ISO/RTOs, many states have developed state-level or multi-state level policies to allocate costs for transmission development.

This section summarizes cost allocation approaches, in general, and provides detail about the specific cost allocation approaches used throughout the country.

4.1 Methodologies

4.1.1 Basic Methodologies

The following are generally accepted methodologies to allocate transmission development costs. Many of these are administered within a region by transmission planning organizations called ISOs and RTOs. These five methodologies are⁵⁵:

- **License Plate:** ratepayers pay transmission rates based on the costs of transmission in the transmission pricing zones in which they are located, but are able to utilize the entire system after based on payment of such rates.
- **Postage Stamp:** transmission costs are recovered uniformly from all customers in a region, such as defined by an ISO or RTO, where the transmission was built.

⁵⁵ EESI, *Typical Bills and Average Rates Report - Winter 2010*. 2010.

- **Beneficiary Pays:** costs are allocated among groups of customers based on the perceived proportionate benefits accruing to each group. Various criteria and formulae exist to determine the benefits.
- **Direct Assignment:** transmission costs associated with interconnecting a generator to a transmission line or other transmission service requests are assigned to the entity requesting service.
- **Commercial Investment** (also known as merchant cost recovery): transmission developers recover their commercial transmission investment costs other than through regulated tariffs. Typically, this involved either selling capacity to transmission customers, usually generators, through negotiated rates. Such developers could be investor-owned utilities (IOUs) or third parties, depending on state and regional rules.

4.1.2 Methodology Variations

Several variations of these basic methodologies are used to allocate transmission capacity and costs in the U.S. Many are designed to either lower overall project risk, or to distribute project risks among multiple stakeholders to alleviate barriers for an individual party.

Open Season. A competitive open season bidding process can be used initially to allocate long-term transmission rights and costs. Revenues to transmission developers are based on results of the bidding process. If a transmission line is owned by an entity affiliated with a participant in energy markets, affiliate concerns must be addressed. Generators may acquire transmission capacity for delivery of electricity to relatively high-cost, import-constrained markets.

Anchor Tenant with Open Season. To fully “subscribe” the transmission line, or find enough customers, the transmission developer may conduct a process known as Anchor tenant with Open Season. Under this process, the transmission developer may enter into development agreement with an Anchor Tenant under which a portion of proposed transmission capacity (e.g., up to 50%) would be pre-subscribed at negotiated rates before the Open Season solicitation of customers in a competitive auction. FERC approved this process in a February 2009 Order.^{56,57} The Open Season/Anchor Tenant Model is particularly important as a means

⁵⁶ Order Authorizing Proposals and Granting Waivers, *Chinook Power Transmission, LLC*, Docket No. ER09-432-000; and *Zephyr Power Transmission, LLC*, Docket No. ER09-433-000, 126 FERC ¶ 61,134 (Feb. 19, 2009).

of obtaining financing before capacity is made available to all potential customers. According to FERC's 2009 Order:

"The financial commitments made by anchor customers prior to an open season provide crucial early support and certainty to merchant transmission developers, which enables them to gain the critical mass necessary to develop these projects."

Participant Funding. Under a "Participant Funding" approach, the transmission customer provides funding in advance for transmission construction. The alternative is transmission owner funding, in which the transmission owner finances construction of the transmission upgrades, and recovers the funds thereafter through transmission rates.

Participant funding with priority to transmission rights. This is a variant on the participant funding method. Under this scenario, capacity in a planned transmission line is pre-sold to a generation facility owner on a long-term basis at cost-based rates to be established in the future. If potential exists to expand the line, other customers would then be given the right to acquire capacity at comparable rates, terms and conditions. The transmission owner may be subject to the traditional obligation to build new transmission capacity under tariff rules.

Purchase Power Agreements (PPA) and Long Term Contracts. PPAs are legal contracts to buy and sell energy. They specify details such as the amount of electricity to be purchased, the price to be paid for it and the time period over which commitments are valid. PPA's can help address market risk, by assuring a buyer for a product. Longer duration PPA's can help reduce financing costs more than shorter ones because they can help debt terms better approximate equipment lifetimes.

Cluster Studies and Renewable Zones. To help circumvent the "chicken-and-egg" dilemma caused by uncertainty in development, some approaches to transmission development have made use of cluster studies or have designated areas as renewable energy zones. In particular, the studies identify areas where transmission development could readily be aligned with economic renewable resources.

⁵⁷ A developer of two merchant transmission projects was allowed to pre-subscribe 50% of the capacity on each line to an "anchor customer." The anchor customer's agreement will serve as precedent for customers later selected through an open-season sale of the remaining capacity on each line.

Precedent Transmission Service Agreements. Used by the Bonneville Power Authority (BPA), Precedent Transmission Service Agreements (PTSA) helps confirm generator interest in transmission services and helps limit the risk that a transmission line will not become fully subscribed. In particular, it sifts out speculative projects by requiring generators to make a down-payment for transmission service and to commit to using the transmission when it is built. Though other factors may ultimately prevent a generator from connecting (e.g., such as failure to permit), this approach helps assess how serious a developer is about subscribing for service.

Overlay. High voltage transmission lines (e.g. 345 kV, 500 kV, or 765 kV) which are developed or overlaid within a region to move power long distances to high energy using regions and cities. Overlay transmission lines often cross thousands of miles and multiple states.

4.2 Application Examples

In practice, cost allocation approaches can contain a mixture of methods. Several regions and states have applied versions of the cost allocation methods noted above, with variations or a mix of approaches is used. Because separate cost allocation methodologies can be applied within a set of cost allocation rules, each section notes which method(s) the regions use for which types of upgrade.

In addition to assessing who ultimately pays the cost for transmission investments, cost allocation methods may also address how an investment is paid for, and who bears the risk of an investment throughout the project. For example, in an attempt to lower the barriers associated with investment financing, some cost allocation methodologies allow one entity to bear costs or risks up front, though a separate party may ultimately pay for the investment.

Table 2 groups cost allocations by their basic method, and notes the application (by ISO/RTO region) and any modifications of that basic method.

Table 2. Transmission Cost Allocation Application Approaches

Method	Application	Modification
Postage Stamp		
	ERCOT SPP PJM MISO ISO-NE	High Voltage Transmission ("Overlay") & Zones By region or zone/utility territory ("Highway/Byway") Projects > 500 kV Partial % is postage stamped for certain projects PTF, but not Generator Interconnections
Direct Assignment		
	CAISO BPA	Zones & Postage Stamp Up Front Open Season & Transmission Agreement
License Plate		
	NYISO PJM ISO-NE	Beneficiary Approval for Economic Upgrades; Exception for Power Authority Projects < 500 kV Non-PTF, and not Generator Interconnections
Beneficiary Pays		
	MISO	Certain projects shares or totals, per size and type
Merchant Cost Recovery		
	NYISO, PJM Neptune Linden	Open Season; Purchase Power Agreement (PPA) Long-term PPA Open Season

Table 3 summarizes approaches by region and state, distinguishing how each one addresses “financing” or “who pays.” Modification terms are defined in Section 4.1.2. A variety of approaches are used to address both the questions of who will pay transmission costs as well as how the costs will be paid (e.g., how it will be financed). However, the issue of financing is not always addressed specifically.

Table 3. Transmission Cost Allocation Application Modifications

Application	"Who Pays"	How Addresses Financial Risks
ERCOT	Postage Stamp	Pre-Approved & Costed; 10% Commitment
SPP	Postage Stamp	Not directly
BPA	Direct Assignment	Transmission Agreement, Open Season
NYISO	License Plate	Not directly addressed
CAISO	Direct Assignment	Postage Stamp Up Front
PJM	Postage Stamp & License Plate	Not directly addressed
MISO	Beneficiary Pays & Postage Stamp	Not directly addressed
ID-WY-MT	Merchant	Open season; Anchor tenant
NTTG	Merchant	Open season; Anchor tenant
KS, WY, IA, ND, SD, CO, NM	Infr / Trans Authority	Varies

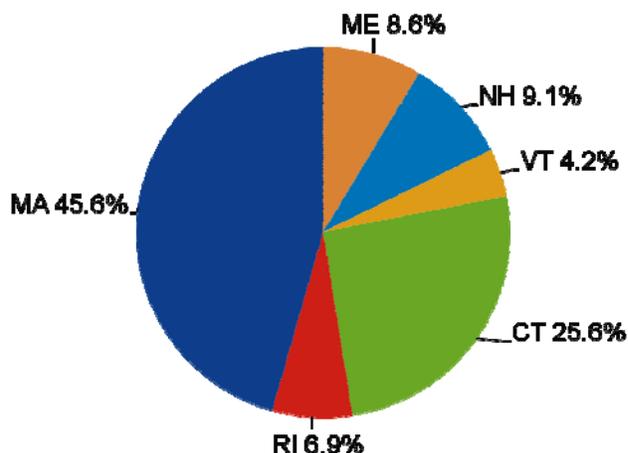
*NTTG = Northern Tier Transmission Group; NTTG is an organization of transmission providers and customers involved transmission transactions delivering electricity to customers in the Northwest and Mountain States.

4.2.1 ISOs/RTOs

4.2.1.1 ISO-NE

ISO-NE is an example of the postage stamp method.⁵⁸ Under the ISO-NE Tariff, certain reliability upgrades identified by the RSP can have their costs socialized. In particular, the costs of upgrades 69kV and above and which qualify as a PTF Facility are fully allocated across load, based on coincident peak loads. Where transmission upgrades are less than 69kV or are not classified as PTF, they are allocated per the ISO OATT under Schedule 21, “Local Service.”⁵⁹ According to 2009 data and as shown in Figure 3, New Hampshire would be allocated 9.1% of the cost, as compared to Massachusetts at 45.6% Connecticut at 25.6%, Maine at 8.6%, Rhode Island at 6.9%, and Vermont at 4.2% for transmission investments in the ISO-NE region that is deemed to improve reliability.

Figure 3. Percent of 2009 Network Load by State



Source: ISO-NE 2010

The ISO-NE Tariff also includes a provision to allocate costs for projects with market efficiency benefits. These “economic” upgrades must be part of the RSP and regarded as beneficial to reducing regional power system costs. As with reliability upgrades, economic upgrades must

⁵⁸ WIRES, *Cost Allocation: A Primer and Current Issues*. 2010.

⁵⁹ ISO-NE Open Access Transmission Tariff, Section II, Available online at: http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sec_II_oatt.pdf

qualify as PTF. If deemed as part of the RSP, and having a net benefit to the market, costs for these upgrades are allocated in the same way as reliability upgrades. No economic upgrade projects have been approved yet for cost recovery under the ISO Tariff.

With regard to generator interconnections, the ISO-NE Tariff allocates the cost of network upgrades needed to meet reliability standards to the generator, along with other associated costs for the interconnection facilities. The exception is where such upgrades would have been required to meet current system reliability needs. In these cases, costs are allocated as reliability upgrades.

Under the present ISO-NE Tariff criteria for market efficiency or reliability upgrades, generator-required upgrades to the Coos Loop or anywhere else in New England would not constitute a reliability or market efficiency project, and thus would not currently qualify for regional cost allocation. To change the ISO-NE Tariff, revisions would need to be filed with FERC by the ISO-NE and Transmission Owners⁶⁰, and regional stakeholders, including six state utility commissions, would likely engage in a comprehensive stakeholder process where consensus would be sought to avoid potential administrative litigation.

4.2.1.2 California ISO (CAISO)

CAISO is an example of the postage stamp method for all network upgrades ≥ 200 kV. Furthermore, specially designated resources may use an up-front postage stamp allocation, which is later charged back to the interconnecting generators.⁶¹ CAISO transmission investments are allocated according to their functions. For reliability or economic upgrades greater than or equal to 200 kV and approved by CAISO, costs are financed by transmission owners and then repaid through a postage stamp rate. Specifically, all system users within CAISO are assessed a transmission access charge, allocated across energy demand, or megawatt-hours (MWh) consumed. CAISO's approval of economic upgrades depends on the extent to which benefits outweigh costs.

For commercial investment transmission facilities approved by CAISO, the project sponsor must

⁶⁰ Similarly, a complaint could be filed with FERC by stakeholders to change existing cost allocation mechanisms; however in such instance consensus would also be necessary for the same reason.

⁶¹ WIRES, *Cost Allocation: A Primer and Current Issues*, 2010.

pay the full cost of construction and operation. However, 100% of the costs are repaid through a regulated cost recovery mechanism or a market-based cost recovery mechanism.

With regard to interconnection facilities, generally the cost is borne in full by the generators seeking to connect.⁶² However, the CAISO tariff also has a provision for what are called Location Constrained Resource Interconnection Facilities (LCRIF). These facilities are high-voltage transmission facilities which support at least two constrained resources, and are radial rather than network facilities. To qualify for the unique allocation of LCRIFs, generators must have demonstrated an interest in at least 60% of the LCRIF capacity. For these types of facilities, the tariff applies a postage stamp approach up front but recoups costs as generation comes online. Specifically, grid users are assessed a transmission access charge for any unsubscribed portions of the line, allocated to load on a MWh basis. (Transmission owners can finance the costs through FERC-approved revenue requirements). Generators pay their pro-rata share as soon as they come online. Assignment of transmission costs to generators, as they connect, based on the maximum capacity of the generator resource relative to the capacity of the LCRIF. CAISO's tariff limits the amount of costs eligible under this tariff such that the investment in LCRIFs is no greater than 15% of all high voltage transmission facilities.⁶³

California represents an approach that removes some of the financial barriers to generation and transmission development. The approach facilitates developing transmission to deliver new power before all the new generation is built, thus resolving the "chicken-and-egg" problem that can stall development. A project known as "Tehachapi" was the first example of a transmission investment requiring location constrained resources interconnection (LCRI) tariff. However, several other projects are being considered. In particular, California has conducted cluster

⁶² Costs beyond direct interconnection facilities are treated similarly to reliability and economic upgrades.

⁶³ 24.1.3.1 (b)(1). "The addition of the capital cost of the facility to the High Voltage TRR of a Participating TO will not cause the aggregate of the net investment of all LCRIFs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) included in the High Voltage TRRs of all Participating TOs to exceed fifteen percent (15%) of the aggregate of the net investment of all Participating TOs in all High Voltage Transmission Facilities reflected in their High Voltage TRRs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) in effect at the time of the CAISO's evaluation of the facility."

studies for various regions within the state, which review accepted generation queue applications and assesses need for additional investment.⁶⁴

4.2.1.3 Electricity Reliability Council of Texas (ERCOT)

ERCOT's approach for transmission being built within Texas' Competitive Renewable Energy Zones (CREZ) is a postage cost allocation approach.⁶⁵ According to the ERCOT tariff, transmission costs for reliability and economic projects approved by the Public Utilities Commission of Texas (PUCT) are allocated to 100% to all load based on average summer peak demand. With regard to direct interconnection facilities, generators are responsible for all of the costs. Upgrades beyond direct interconnection are paid for by the transmission service provider and allocated across load based on average monthly coincident peak using a postage stamp approach. Once wind developers show commitment (through a letter of credit amounting to 10% of the project), then transmission companies will build the lines with the cost allocated 100% to ratepayers across all of the state.

In 2005, Texas State legislation raised the RPS, mandated a process be used to identify CREZs to meet the RPS.^{66,67} The legislation also required the PUCT to allow utilities or transmission service providers who developed transmission within the CREZ to rate base the costs of transmission. ERCOT worked with the PUCT to identify high-potential areas for wind and potential transmission solutions. In 2008, PUCT defined five CREZs and assigned \$4.93 billion of CREZ transmission projects to be constructed by seven transmission and distribution utilities.⁶⁸ The PUCT selected transmission options and established a competitive bidding

⁶⁴ Section 4.2 of CAISO's Large Generator Interconnection Procedure (LGIP) (Appendix U to the CAISO Tariff). FERC granted the CAISO authority to use a "clustering" approach to process Interconnection Requests. In particular, clustering entails studying all Interconnection Requests made in given period as a group rather than serially when assessing system impacts of interconnection. Projects greater than 20 MW are studied in clusters while projects equal to or less than 20 MW are studied serially.

⁶⁵ WIRES, *Cost Allocation: A Primer and Current Issues*, 2010.

⁶⁶ Texas Senate Bill 20, 79th Leg. Reg. Sess. (2005).

⁶⁷ In a 2006 rule, the PUCT defined three criteria by which to identify a region of Texas as a CREZ. These criteria include a region's production capability, the level of financial commitment by generators in the region, and other factors such as the likely cost of transmission to connect resources in that zone. 25.174(a)(4).

⁶⁸ PUCT Order 33672.

process for transmission to serve these renewable zones. The process was open to outside bidders. However, recent legislation restricts new entrants.

Texas is an example where preemptive, system-wide renewable generation and transmission planning occurred to guide transmission cost allocation rules. In addition, the State was one of the first to have transmission competitively bid, rather allocated directly to a utility. Unlike other ISO/RTO regions, the state public utilities commission, the PUCT was directed to have an influential role in selecting transmission projects which would by default have a rate-based cost recovery.

4.2.1.4 Southwest Power Pool (SPP)

SPP is an example of a postage stamp method.⁶⁹ On June 1, 2010, FERC approved a revised tariff for SPP, which included a new approach to allocating certain transmission costs in the region. SPP's revised cost allocation methodology applies varying degrees of regional versus local allocation, depending on transmission size, using a postage stamp approach. Projects which qualify under this "Highway/Byway" approach include projects identified as Base Plan Upgrade projects selected by the SPP Board of Directors. These include economic upgrades designated as priority projects and other projects arising from SPP's transmission planning process, including approved projects associated with wind generation resources in the region. Generator interconnection costs do not qualify, and as such remain the responsibility of the generators.

The scope of allocation varies with the size of the transmission. In particular, transmission equal to or over 300 kV or more are allocated 100 percent across the region. Transmission equal to or below 100 kV is paid for entirely within its zone. Transmission between 100 and 300 kV has one-third of the cost allocation regionally and two-thirds of the costs allocated within the zone. These regional zones correlate to existing SPP pricing zones.

The intent behind the cost allocation approach is that larger, high voltage transmission projects tend to benefit the entire region where smaller facilities have more local benefits. Also, the revised tariff more closely links the system planning process, providing a way to allocate costs designated in the regional planning process. Because the tariff focuses on transmission size and projects identified in the transmission planning process, the new tariff limits allocating

⁶⁹ WIRES, *Cost Allocation: A Primer and Current Issues*, 2010.

transmission costs separately by function. For example, the change eliminates a previous approach to allocating wind-related projects on a MW-mile basis and allocates all qualified wind projects based on size. This assures, for example, that wind-related projects 300 kV or greater will be fully socialized across the region.⁷⁰ The revised approach facilitates integrating renewable resources from the western areas of the region with load centers in the east.

4.2.1.5 Midwest ISO (MISO)

The MISO tariff's cost allocation provisions are an example of the postage stamp approach. As of the publication of this report, additional variations to the tariff are pending FERC approval, as of October 2010. Currently, the MISO tariff allocates transmission costs according to the purpose of the upgrade, including reliability projects, economic upgrades and generator interconnection projects. The allocation for reliability upgrade projects vary by size. For projects involving transmission of 345 kV or more, 80% of the costs are allocated to load within the region based on a flow-based approach. The remaining 20% is allocated to load across the entire region on a postage stamp basis, according to average coincident peak. For reliability projects between 100 kV and 345 kV, the tariff allocates costs entirely within the region using a flow-based approach. All projects must have costs exceeding 5 million or be 5% or more of a transmission owner's net plant. In addition, the MISO tariff specifies a cost allocation approach for PJM/ Midwest ISO cross-border projects. Here the allocation uses a flow-based approach to ascertain each RTO's contribution to the constraint causing the upgrade. Once allocated to each region, the costs are then allocated according to each region's usual tariff.

To qualify for cost allocation under the MISO tariff, economic upgrades must be 345 kV or greater and cost over \$5 million. Furthermore, MISO must determine that the benefits outweigh the costs. For these cases, the tariff allocates 20% of the costs to all transmission customers in the region, on a postage stamp basis. The remaining 80% of the costs are allocated across three planning sub-regions based on based on estimated benefits, and allocated on a postage stamp basis within the sub-region.

In July, 2010, MISO proposed an additional transmission cost allocation method for Multi-Value Projects (MVPs).⁷¹ If adopted, it will result in adjustments to cost allocation for generator interconnection projects. Originally, for generation interconnection projects, generators

⁷⁰ SPP Filing April 2010, pp. 8, 21-22.

⁷¹ MISO Filing July 2010.

generally had to pay the entire cost of Network Upgrades in advance of construction for projects smaller than 345 kV. For projects over 345 kV, generators had to pay 90% of the costs and 10% was allocated system wide, based on coincident peak. Where a generator could demonstrate that it was a designated Network Resource or that it had committed to supply at least one year of capacity when it began operation, then the generator could be reimbursed for 50% of the costs of the Network Upgrades.

MISO's proposed cost allocation methodology for MVPs allocates 100% of all Network Upgrade costs to all load and exports, using a per-MWh charge, on the basis that MVPs and their associated transmission upgrades provide region-wide benefits to the MISO footprint as a whole, from load and exports. To qualify as an MVP the transmission project must be over 100 kV. The MVP charge will be based on the annual revenue requirements reported by each MISO Transmission Owner for projects that meet the MVP criteria. The MVP charge is proposed to be applied on a usage (i.e., MWh) basis rather than a demand (i.e., MW) basis.

According to the an AWEA filing, the MVP approach would allow certain transmission development projects associated with renewable energy development to qualify for complete socialization of costs. In AWEA's words:

"With respect to renewable resource development, this process would be similar to the Competitive Renewable Energy Zone ("CREZ") process that ERCOT used to identify areas (or zones) of Texas most appropriate for wind development, and then to design transmission additions needed to support development in those zones."⁷²

4.2.1.6 Pennsylvania New Jersey Maryland ISO (PJM)

PJM is an example of a postage stamp approach as well as a license plate approach. The postage stamp approach is for transmission 500 kV and above (all transmission service customers in a region pay a uniform rate per unit-of-service, based on the aggregated costs of all covered transmission facilities in the region). New reliability and economic-based projects less than 500 kV are recovered under a license plate approach, where costs are allocated based on flow impacts determined from peak conditions. However, PJM and FERC in continued litigation and numerous FERC compliance filing obligations have dampened use of the postage stamp cost recovery method. PJM's economic planning and cost allocation mechanism contains specific criteria for measuring benefits and costs as well as specific

⁷² AWEA Draft Filing, Unofficial Copy. 2010 p. 24

benefit/cost tests for evaluating projects. PJM was ordered to develop such mechanisms as a condition of its approval as an RTO.

4.2.1.7 New York ISO (NYISO)

NYISO is an example of a license plate approach to transmission cost allocation for projects related to reliability and economic upgrades. The exception is recovery of New York Power Authority's (NYPA) costs, which are socialized across all New York transmission users via the NYPA Transmission Adjustment Charge (NTAC).

According to the NYISO tariff, upgrades addressing local reliability issues are allocated to the zone or zones in which the reliability issue was occurring, where coincident peak load determines allocation across zones affected. For upgrades solving region-side reliability issues, the tariff allocates costs to the whole NYISO region, based on each zone's share of coincident peak load.

To be eligible for allocation under the NYISO tariff, economic projects must pass a cost-benefit test such that the projected benefits outweigh costs over a ten year period. In addition, the costs must be greater than \$25 million and at least 80% of the beneficiaries must approve the project. Beneficiary votes are weighted by their share of potential energy savings. As with a reliability upgrade, costs are allocated to zonal beneficiaries. However, allocation across zones is based on energy savings and allocation within zones is based on share of total energy in the zone.

Under the NYISO tariff, generators are generally responsible for costs associated with meeting minimum interconnection standards. Where a party may elect to make additional upgrades, that party may be reimbursed by other parties connecting in the future and benefiting from these additional upgrades.

Recently, two merchant transmission development projects to deliver power between PJM and NYISO used cost allocation methods outside of the NYISO tariff. The first, the Linden Variable Frequency Transformer project (Linden VFT),⁷³ used an open season auction approach to fund a 230 kV line that would provide additional capacity over an existing transmission line. In

⁷³ Linden VFT LLC is a new Delaware limited liability company, formed by GE Energy Financial Services Inc. to develop the merchant transmission project.

particular, FERC approved an anchor tenant to pre-subscribe transmission capacity prior to such capacity being offered to other developers through FERC's open season process.

The second project, the Neptune RTC (Neptune), developed a long-term purchase power agreement (PPA) with the municipal utility, the Long Island Power Authority (LIPA) to help fund a new 500 kV HVDC line. Under the PPA, LIPA pays Neptune a fixed tariff with a negotiated rate for the rights to transmit power over line.

4.2.2 State & Regional

Several single-state and multi-state collaboratives have also developed approaches to transmission cost allocation. The following sections outline some of these.

4.2.2.1 Bonneville Power Administration

The Bonneville Power Authority's (BPA) is an example of the Network Open Season Approach to transmission allocation for several transmission projects in the area. In particular, BPA developed what is termed a Precedent Transmission Service Agreement (PTSA). Here, BPA offers of transmission service at embedded rates where transmission complies with certain precedent terms and conditions as determined by BPA. In the first open season, generators were given one month to sign and return the PTSA and were required to deposit an amount equal to one year's worth of transmission service. The PTSAs apply to BPA transmission only and not regional interties.

The approach was implemented to solve what was an overwhelming number of requests in interconnection queue. The approach sifts out 'speculative' projects, e.g., those not participating in the Open Season. With the open season approach using PTSAs, BPA was able to review projects with a higher level commitment, and then identify existing transmission capacity to accommodate projects. All other projects unable to connect to the existing lines became part of a large cluster study for the BPA grid as a whole.

Overall, generators pay for the cost of transmission and BPA pays for associated engineering and design studies. Where a transmission request would require payments in addition to the transmission rate listed by BPA, then the PTSA is terminated and transmission customers must pay for the required studies.

4.2.2.2 Western States

Several western states have been engaged in transmission development outside of the ISO/RTO mechanisms. These subsections describe some case examples from these states. A subsequent section describes the use of transmission authorities, also present in many western states.

The Northern Tier Transmission Group is a non-RTO transmission organization made up of Northwest and Mountain states, including: Idaho, Oregon, Montana, Wyoming, and Utah. The Group, comprised mainly of IOUs and state representatives, coordinates transmission operations and planning, and is initially focused on developing inexpensive and relatively easy improvements to grid management. They have developed cost allocation principles for transmission projects across the region, including recommendations for license plate cost recovery based on project ownership and reliability obligations.

Idaho has numerous merchant transmission projects progressing through approval stages. Per a 2009 FERC Order, these are anchor tenant with open season to secure transmission customers where an anchor tenant signs up for large portion of capacity, typically 50%, with open season for rest. Notable proposed projects are:

- TransCanada's proposed Zephyr and Chinook HVDC lines;
- Jade Energy Associates' Overland Transmission Project;
- Great Basin Transmission's Southwest Intertie Project

For the Zephyr & Chinook project, a market-driven open season process successfully allocated 3,000 MW to three wind developers building in Wyoming. The Zephyr project would originate in Wyoming while the Chinook project would originate in Montana. The open season approach allowed the transmission developer to secure enough money from customers to cover half the regulatory costs, up to a cap of \$70 million, while the investor paid for the other half of this phase. The renewable developers were required to sign no obligation Precedent Agreement and had a defined time period in which to secure a PPA before a firm transmission agreement was required, during development phase. Generators were responsible for building facilities to connect to the converter stations.

In another project, the Idaho Public Utilities Commission approved a negotiated settlement between small wind developers and a local utility to share transmission upgrade costs. In particular, 25% of the costs were paid by the wind developer, 25% were paid by Idaho Power

and allocated to utility's rate base for recovery from ratepayers system-wide and 50% was advanced by the transmission developer, but refunded by ratepayers, over a term "not to exceed 10 years after the projects are commercially viable." The Idaho Public Utilities Commission noted that requiring developer payment of only 25% is beneficial to all customers because it creates an incentive for developers to consider economic efficiencies when they choose locations for their wind farms. The renewable projects will sell their entire output to Idaho Power, whose customers are spread between Idaho and Oregon.

4.2.2.3 Transmission or Infrastructure Authorities

Several states have developed state-level authorities, called Infrastructure Authorities or Transmission Authorities (hereafter, transmission authority), to facilitate transmission development in within the State. Some examples include Colorado, New Mexico, Iowa, Kansas, North Dakota, South Dakota, and Wyoming. Transmission authorities were created by respective legislatures to address transmission needs within the state including transmission cost allocation, design studies, and environmental review. A variety of approaches have been taken to organizing these authorities. In Wyoming, for example, the transmission authority consisted of members appointed by the Governor. In addition, powers granted to the different transmission authorities vary. In Wyoming, the transmission authority was granted the ability to issue revenue bonds to finance projects.

Public entities such as transmission authorities can have broader purposes, including economic development and job creation. In contrast, the ISO-NE focuses solely on electricity and has no mechanism to take into account job creation. Wyoming, the first U.S. transmission authority created in 2004, has the stated mission to "*...diversify and expand the state's economy through improvements in Wyoming's electric transmission infrastructure to facilitate the consumption of Wyoming energy in the form of wind, natural gas, coal and nuclear, where applicable.*"⁷⁴

4.3 Additional Concepts

Previous to this study, and during discussions held with stakeholders for this study, additional cost allocation methodologies were suggested by stakeholders. Suggestions are aggregated below by approach type.

⁷⁴ Accessible at: <http://wyia.org/about-us/>. Accessed August 3, 2010.

Local Ownership. One recommendation was that legislation be enacted to authorize Coos County or another economic development body to own and operate transmission facilities. A separate stakeholder proposed a sort of “private toll road” between generation and local loads. In particular, the stakeholder suggested an investment model where Coos County bonds the cost of transmission and the State of NH guarantees or financially backs the County Bonds, resulting in a lower rate. The bonds would guarantee a return on equity investment. A regional public authority would support Coos County in making the required investment. Each taxpayer in each community of the county would receive a direct tax reduction benefit when the county receives additional income from the project. The benefit of this approach, according to the stakeholder is that Coos County taxpayers are direct beneficiaries rather than outside investors. Another stakeholder proposed amending RSA 162-G to make renewable energy facilities eligible for industrial development bonds.⁷⁵

Public-Private Partnerships. Additional suggestions included creating a public-private partnership with a merchant transmission provider which would allow the provider to use existing rights of way. The approach would allow a private developer to invest in a transmission upgrade in return for the opportunity to earn a return on its equity investment.⁷⁶

Transmission Authority. This entity would serve as catalyst or organizer to facilitate transmission infrastructure development, similar to other states noted above. Anbaric Power summarized how such an authority could work in the state:

“One idea would be for the authority to become the customer for the capacity on a new transmission line through a long-term contract with a transmission developer. As is done in Texas the right to build the line could be put out to competitive bid, where entities like NEITC, PSNH, National Grid or other transmission developers would compete to build the line under a long-term contract with the transmission authority. As renewable energy developers then came on to the line, they would assume their proportional share of line’s cost and eventually the transmission authority contract would no longer be necessary. I’m sure there are several other iterations of this approach that would hold promise for getting a line built to serve Coos County and support the economic development of the

⁷⁵ NHPUC, *Commission to Develop a Plan for the Expansion of Transmission Capacity in the North Country: Progress Report. Pursuant to SB 383 Chapter 348, Laws of N.H. 2008.*

⁷⁶ NHPUC, *Background Report on New Hampshire Transmission Infrastructure, 2007.*

region. KEMA's work presents a good opportunity to explore this beyond the traditional and difficult cost allocation methods".

State-Based Mechanisms to Finance Transmission Development and Procure

Generation. Another proposal elaborated on that outlined above. In particular, the stakeholder suggested that New Hampshire create a transmission authority which could contract the full capacity of a new transmission line in the North Country. In particular, in a manner similar to the Neptune project described above, the authority could subscribe capacity on the line via long-term contracts with the transmission owner, which in turn would help finance the line. Via a competitive procurement process managed by the authority or the NHPUC, generation could be added to the line after it is built. In particular, the authority or NHPUC could procure a defined percentage of renewable energy and allocate the cost of that procurement on a percent load basis to each of the electricity providers in the State. NHPUC procurement could be used to meet a portion of the State's standard offer, as in Maine. Using a competitive process has the intent of limiting the overall cost of procurement. To help lower the risk assumed by the state, the proposal would engage mechanisms such pre-subscription via a PTSA as used by BPA or down-payment via a letter of credit as used in ERCOT. The intent of the approach, as described by a stakeholder, is to provide transmission certainty to a renewable developer at a known cost of transmission. Furthermore, the intent of the proposal, as defined by the stakeholder, is to capture economies of scale by having the State contract for a larger capacity line than a single generator would otherwise build, and to allow the State to provide a lower cost of debt service than would otherwise be available.

Reconfigure Coos Loop into a Network Upgrade. Some stakeholders have proposed re-designing the Coos Loop to make it a transmission facility where upgrades would have regional reliability or market efficiency benefits.

Equal Cost Distribution and Up-Front Financing. Instead of determining the costs of transmission upgrades payable separately by each of the generators depending on its spot in the queue, New Hampshire (or any other party providing up-front financing) could establish a cost-recovery arrangement which would impose the same cost on each of the generators until all of the capacity had been subscribed and commitments had been made to facilitate full cost recovery.

Senate Bill 164. In 2009, Senator Gallus and Representatives Remick, Rappaport and Theberge sponsored legislation that would have allocated transmission costs related to northern New Hampshire's electrical transmission system. The legislation proposed establishing the northern New Hampshire electrical transmission system improvement fund (Fund) to help cover

the costs of transmission development. The legislation would have appropriated \$155,000,000 to Fund the NHPUC to administer the funds, which would have come from a variety of sources. In particular, 20% would be paid by new generation developers at the rate of \$105,000 for each developed megawatt of power. 20% would be paid by New Hampshire ratepayers through a transmission charge on electricity, 5% would be derived from state-issued bonds and 50% would be paid for through federally-funded programs.⁷⁷ The legislation did not make it out of the Senate Committee on Energy, Environment and Economic Development.

⁷⁷ When SB 164 was first drafted, it appeared that American Recovery and Reinvestment Act funding would be available for transmission investments in remote areas that were rich in renewable energy resources. The final version of the bill, however, deleted those provisions.

5. Transmission Cost Applications in New Hampshire

5.1 Cost Allocation Impacts

As noted in Section 4, transmission cost allocation approaches appropriate the costs, as well as risks, amongst stakeholders. As such, the approaches address the question of who pays and how, and who takes on market and project risks associated with the project. At a high level, Table 4 illustrates how the basic cost allocation methods discussed in Section 4 allocate costs and risks.

Table 4. Comparison of Basic Cost Allocation Impacts on Stakeholders

Approach	Project Costs & Risks
Postage Stamp	Ratepayers
Direct Assignment	Generation Developers
License Plate	Ratepayers
Beneficiary Pays	Beneficiaries (combination of groups)
Commercial Investments	Transmission Developers

In general, postage stamp and license plate approaches allocate costs and risks to ratepayers. Direct assignment approaches allocate costs and risks to generation developers. Commercial investment approaches allocate costs and risks to transmission developers. Beneficiary approaches pays may result in multiple parties contributing, including ratepayers and developers.

Furthermore, additional methods have been developed to separate out the allocation of direct costs from project risk. Variations on the basic methods, for instance, can alleviate project and market risks by distributing risk across multiple stakeholders, by allocating risk to different stakeholders over different time periods in the project, or by introducing processes that clarify the demand for a product. As noted in Section 4, an Open Season approach defines a process by which to subscribe energy developers to a transmission line, before the line is built. This can help assess demand for a transmission project before development of the transmission line moves ahead, and clarify the revenue a developer would receive for their investment.

Furthermore, a renewable energy developer is assured that it has transmission capacity over which to deliver its product. Anchor Tenant with Open Season addresses the risk that a line may be undersubscribed even though there appears to be demand for it. Typically, a single anchor tenant may have majority stake in a line, allocating a more substantial commitment for transmission a single entity. Precedent Transmission Service Agreements help confirm generator interest in transmission services by sifting out speculative projects before an open

season. Cluster Studies or Zone Definition can also help assure that customers for transmission development exist. In particular, studies identify areas where transmission development could readily be aligned with economic renewable resources. PPAs help provide certainty to energy developers that it can sell its product once it is built.

Table 5 summarizes at a high level how ISO/RTOs provisions, which can use a mix of approaches, allocate costs and risk. Because approaches often vary depending on the type of transmission project, and because the focus of transmission development in the North Country is to enable renewable development, the table outlines transmission cost allocation approaches related to renewable energy-related projects only. Additional stipulations exist for each of the cost allocation methods summarized in Table 5, though the table does not describe them in full. Rather, Section 4 contains additional detail, as do reference documents.

Table 5. Allocation of Costs and Risks by Example Cost Allocation Approaches

Approach	Cost	Risk
CAISO	Generation Developers	Ratepayers
ERCOT	Ratepayers	Ratepayers
ISO-NE	Generation Developers or Commercial Investors	Generation Developers or Commercial Investors
MISO	Ratepayers	Ratepayers
NYISO	Generation Developers or Commercial Investors	Generation Developers or Commercial Investors
PJM	Generation Developers or Commercial Investors	Generation Developers or Commercial Investors
SPP	Ratepayers (generator interconnection does not qualify)	Ratepayers (generator interconnection does not qualify)

NYISO, PJM and ISO-NE take a direct assignment approach or commercial investment approach where a project does not result in reliability or market efficiency improvements. As such, the method allocates both cost and risk to generation developers or transmission developers. In ERCOT, MISO and SPP, ratepayers are allocated both costs and risks for a limited set of projects related to renewable energy developments. These projects have specific criteria to qualify and are generally tied to transmission planning processes within the region. Linkage to the planning process makes sure that the projects are vetted before ratepayers bear the costs. In SPP, generator interconnection projects do not qualify.

CAISO takes a slightly different approach. For projects associated with location-constrained resource, generators must ultimately pay for the transmission but ratepayers pay for the costs up-front. In addition, cluster studies done as part of the transmission planning process help match transmission projects with potential renewable generation resources, ensuring availability

of renewable energy projects to subscribe to the transmission line. Furthermore, total investment in transmission associated with location constrained resources is limited, effectively capping the amount of risk ratepayers will bear.

5.2 Implementation in New Hampshire

Due to differences in regional and state regulations and to differences in the geography and characteristics of existing transmission and generation assets, methodologies used in other regions of the U.S. are not necessarily appropriate for northern New Hampshire. However, the intent behind many approaches may remain valid, or slight modifications to the approaches can make them applicable to northern New Hampshire. The following sections examine the applicability of several cost allocation methods to northern New Hampshire and outline how variations of some approaches might be applied to northern New Hampshire. First, a discussion of the impacts of basic cost allocation approaches to New Hampshire stakeholders follows.

Implementation of Basic Approaches

The direct implementation of postage stamp, license plate, and beneficiary pays approaches to transmission cost allocation in the North Country would require changes to the ISO-NE Tariff as they are all tariff-based approaches involving regional ratepayers. Direct assignment and commercial investment projects would not require ISO-NE Tariff changes because they do not involve ratepayers.⁷⁸

- **Postage Stamp** → Requires changes to tariff
- **Direct Assignment** → Requires variations to address impediments
- **License Plate** → Requires changes to tariff
- **Beneficiary Pays** → Requires changes to tariff
- **Commercial Investment** → Requires variations to address impediments

⁷⁸ Depending on whether prior filings were made with ISO-NE, some entities might have to submit filing with ISO-NE.

If implemented at a state-level, postage stamp, license plate and beneficiary pays approaches would require approval by FERC. Additional variations on these basic approaches, including transmission authorities, could be applied in a similar fashion in New Hampshire. However, in some cases, legislation would need to be passed by the legislature to provide authority (such as with a transmission authority) or to appropriate funds (such as for assistance with studies). Transmission service agreements, Open Season, Anchor Tenant and PPA processes and agreements could be conducted through the NHPUC.

Applicability of Cost Allocation Examples

Though some methods would need to be adjusted to be implemented in northern New Hampshire, other approaches would have very limited applicability even if they were adjusted. In particular, NYISO and PJM's approaches to cost allocation are similar enough to ISO-NE's that they do not directly address current impediments to transmission development in the North Country.

With regard to SPP's highway/byway approach, only a limited set of its provisions are applicable to New Hampshire. To start, the SPP cost allocation approach does not apply to generation interconnection. In addition, because other upgrades to the transmission system in the northern New Hampshire projects would likely not cross the SPP tariff's threshold of low to high voltage, taken within the context of transmission upgrades that fit within the \$150 million range, the approach would simply allocate one-third of the costs to ISO-NE ratepayers and two-thirds to ratepayers within New Hampshire. This approach would require significant changes to the ISO-NE Tariff. A variation to this approach could allocate one-third of the costs to ratepayers in the State and two-thirds of the costs to North Country ratepayers. However, researchers believe that the cost-sharing split found in the SPP study is not necessarily relevant to ISO-NE or even New Hampshire. Studies done by the SPP to justify this cost-share are not directly applicable to ISO-NE or New Hampshire. Additional studies would need to be done, in a similar fashion to what was done in SPP, to assess appropriate cost allocation shares.

In general, the five basic approaches to transmission cost allocation are applicable to New Hampshire. The next section discusses likelihood of success given stakeholder input, and apparent requirements for implementation.

Approaches to Implementing Remaining Cost Allocation Examples

The following paragraphs highlight ways in which additional ISO/RTO cost allocation approaches could be implemented in NH and what they would require to move forward.

ERCOT. At its heart, the ERCOT cost allocation approach is a postage stamp approach. State-level transmission planning evaluation and the identification of cost-effective renewable resources, however, heavily guide the selection of transmission project which can be socialized through a postage stamp approach. Were New Hampshire to implement an approach similar to ERCOT at the state level, ratepayers would be charged transmission development costs and the NHPUC would assign a set amount for that development, and would select specific transmission options for development. Were a similar approach to be taken at the ISO/RTO level, the ISO-NE would conduct a study identifying cost-effective renewable energy zones, and coordinate with state agencies to similarly coordinate transmission design. Similar regional efforts have been underway to assess renewable energy potential in New England and propose possible transmission designs. However, there is no effort currently underway to adjust the ISO-NE Tariff to ratebase projects without reliability or market efficiency benefits.

CAISO. In order to implement an approach to transmission cost allocation similar to CAISO in ISO-NE, it would require a change to the ISO-NE Tariff to define location constrained resources. The revisions would have ratepayers cover development costs until power developers come online. Implementing a state-level approach would entail collecting funds from state ratepayers to pay for transmission until power developers were to come online.

MISO. The proposed MISO MVP approach would allocate costs to load sources and export sources on a per-MWh basis. As such, renewable energy developers would share a portion of the costs. Because New Hampshire is a net exporter of power, allocating costs to loads at a high-level could indicate one should allocate a share of the costs to other states. This implementation approach would require changes to the ISO-NE Tariff. Should the approach be implemented within the State only, a charge would be assessed to ratepayers based on their relative load.

- **“ERCOT” State Approach** → Requires allocating costs to ratepayers
- **“CAISO” State Approach** → Requires allocating risks to ratepayers
- **“MISO” State Approach** → Requires allocating costs to ratepayers and power developers

Overall, a state-level implementation of ERCOT and CAISO approaches would allocate costs or risks to ratepayers within the State. MISO would allocate costs to rate payers and power developers.

In implementing a rate-based cost allocation approach, the cost allocation mechanism must specify the ratepayers from whom the costs will be recovered. In particular, there are multiple electricity providers operating in the State and all or some of the cost could be distributed across the customers of these providers. In addition, any such approach would require modifications to the ISO-NE Tariff. Approaches that allocate costs to ratepayers would need approval by FERC.

In particular, as noted earlier, the ISO-NE Tariff contains provisions for transmission over local transmission facilities (LTFs). Electricity rate adjustments associated with upgrades to the Coos Loop would likely go into the appropriate provider's Local Service Schedule, and be recovered by the users of their system.⁷⁹ Another example is a subpart of the Northeast Utilities tariff that relates specifically to Connecticut for coverage of localized PTF transmission development⁸⁰. By isolating a sub-group of ratepayers, the rest of New England does not cover these costs. In order to make this adjustment to the tariff, a FERC filing would be required.

5.3 Ranking & Suggested Approaches

This study used a series of criteria to rank cost allocation approaches for implementation in New Hampshire. These criteria, in no particular order, are:

- Public support
- Ratepayer Impact
- Generator Impact (e.g., viability for generators to connect)
- Regulatory viability and support
- Timing and ease of implementation

Discussions with stakeholders indicated a strong resistance to any plans that would modify the existing cost allocation approach in the ISO-NE Tariff or that would increase costs to electricity

⁷⁹ The appropriate entity would depend on who owns the transmission system, and which rates the costs are allocated from.

⁸⁰ The "Localized Cost Responsibility Agreement(s)" refer to costs associated with a reliability upgrade that exceed ISO-NE's reliability requirements due to aesthetic or other non-reliability related cost approved in the state siting process. The incremental cost associated therewith are not regionalized, but instead are allocated to the local area where such costs were incurred pursuant to a FERC filed agreement.

ratepayers. In particular, there was a strong preference among the public and public advocates, among others, not to have ratepayers pay. As such, approaches involving ratepayer impact ranked low with regard to public support and ratepayer impacts. Though one variation on ratepayer involvement is to have ratepayers effectively make a short-term loan rather than to pay the costs, stakeholders showed concern about assuming risks when they did not find any tangible direct benefits in return. For example, stakeholders perceived the promotion of transmission development and renewable energy in the North Country as state policy-based initiatives, with potential indirect benefits to them, but limited direct benefits not worthy of adopting risk. Generator impacts appeared to be beneficial as generators would be able to pass on costs or distribution risks. Regarding timing and ease of implementation and regulatory viability, approaches which incorporate rate-basing of costs or risks would require FERC approval.

Approaches that did not require ratepayer involvement appeared to rank high with regard to public support and ratepayer impact. However, in order to enable renewable resource projects to move forward, additional measures could be taken which operate within the current regional cost allocation framework, and which promote transmission development. Timing and ease of implementation and regulatory viability and support also rank slightly higher in this regard given that approaches would likely use mechanisms such as PPAs, open auction and transmission authorities, already used in the U.S. Generator impact could vary depending on the extent to which these approaches fully cover transmission costs or risks.

Initiatives in which the State takes on the costs or risks associated with cost allocation are apparent in some state approaches to cost allocation – in particular approaches involving transmission authorities. Here, there are no ratepayer impacts. However, New Hampshire citizens would share the costs or risks of a project. The extent of the allocation amongst developers and the public would depend on the specific plan. For example, in some states, the state's involvement is simply to provide a loan or cheaper financing, and not cover the full expense of the transmission costs. In other cases, subsidies are provided. In terms of public support, the perception that the benefits of the developments address state-level goals would rank this approach higher than a ratebasing approach with regard public opinion. However, the use of State funds needs to be carefully assessed to attract support. With regard to regulatory viability, this type of approach appears to rank highly as approval would not be required by agencies regulating electric utility rates. With regard to support and timing and ease of implementation, this would likely depend on the legislative process and the ability to pass the required legislation to authorize funds and responsibilities.

Results Summary

A review of cost allocation approaches and ways to implement them in New Hampshire indicates that there are available a variety of means to address barriers to transmission development in the North Country. For example, the “chicken-and-egg” problem of transmission development appears resolvable through a variety of financing approaches which disperse project risk. In addition, firm commitments by electricity customers and firm commitments by transmission customers, can help identify demand.

Non-tariff based approaches to transmission cost allocation are relevant to northern New Hampshire, and include such approaches as transmission authorities, PPAs, auctions and up-front loans or payments. The transmission authority approaches would not require changes in the ISO-NE Tariff regarding cost allocation, but would require certain FERC filings related to transmission operation and control. However, the establishment of a transmission authority might be more contentious and time consuming to put in place as opposed to other near term strategies to develop transmission,

As a result of its analysis, this study identifies the direct assignment approach and commercial investment as recommended approaches. The following variations are viewed as high value tools for developing the required transmission facilities in northern New Hampshire:

- Commercial Investments
- Direct Assignment
- Purchase Power Agreements
- Transmission Service Agreements
- Anchor Tenant or Open Auction
- Transmission Authority
- Up-Front Loans with Repayment by Generators

Section 7 provides detail on proposed framework for an action plan on transmission cost allocation which incorporates these elements, and makes them specific to the State of New Hampshire and the North Country.

The following approaches are valid and often high-value approaches where they are used. However, their benefit for use in the North Country appears to be limited due to their time to implement, ability to address North Country development barriers, or likely support amongst stakeholders. These include:

- Socialization of costs in customer ratebase

-
- Identification of Renewable Energy Zones
 - Highway-Byway approach

6. Financial Studies and Analyses

To assess the application of cost allocation methods in northern New Hampshire, researchers compiled information on the costs and benefits of transmission and of cost allocation methodologies on stakeholders. The following section summarizes costs and benefits, according to available information. It then assesses the impact that transmission costs and benefits might have on local stakeholders in northern New Hampshire.

6.1 Cost and Benefit Factors Summary

6.1.1 Costs

Attempting to determine the cost of transmission upgrades without performing a detailed engineering analysis and design is difficult. As such, the current estimates are approximations. Nevertheless, they provide a rough assessment of the scope of potential costs. The intent of this study is to assess how to allocate costs on the order of \$150 million, plus or minus twenty percent. KEMA believes that such costs represent a reasonable range for integrating 400 MW of additional power into the Coos Loop.

6.1.1.1 Financing

Few details were available regarding the financing of proposed transmission and generation projects in the North Country. In addition, information about the finances of renewable developers is not generally publicly available and is difficult to assess in many cases. Furthermore, generalizations are difficult to apply when assessing the specific advantages and disadvantages of a particular cost allocation methodology for the North Country. Nevertheless, it is worth noting that the financing costs for renewable energy developers can range from 1.5% to 6% of the cost of a project. Mechanisms to reduce financing costs can lower overall project costs, and in some cases make a previously unattractive project appear to be attractive. This is especially true for smaller developers where the cost of financing can be higher than for larger, more established companies. Furthermore, financing costs are likely factored into the electricity prices offered by a developer. As such, the higher the debt level, the more developers may need to charge for their commodity.

6.1.1.2 Relative Cost of Designs by Capacity

Transmission development costs can vary by the amounts of renewable power being considered. A project designed for 400 MW would likely be more expensive than one designed

for 200 MW. However, because different approaches might be taken to developing transmission to connect different amounts of renewables, the \$/MW costs could vary depending on the total MW's being discussed. For example, it could be that building for 400 MW is more expensive than building for 200 MW, but that building for 1,000 MW is less expensive on a \$/MW basis than building for 400 MW. Overall, this implies that the design of a transmission project is key in determining the cost per MW connected. Furthermore, a piecemeal, incremental approach to transmission development could come at a greater cost than a plan that considers the full potential under a single design.

6.1.1.3 Electricity Prices

Electricity prices depend on a number of factors, including electricity supplier, sector type, and for the commercial and industrial sectors, peak demand. New Hampshire has a deregulated competitive market for electric power. As such, customers can choose who they purchase power from.

Residential electric rates in New Hampshire vary from about 0.13 to 0.24 \$/kWh, depending on utility, with an average of about 0.17 \$/kWh. For the non-residential sector, rates vary from about 0.12 to 0.20 \$/kWh, depending on utility and peak demand.⁸¹

Table 6 illustrates estimated residential electricity rates by utility for 2009.

⁸¹ EESI, *Typical Bills and Average Rates Report - Winter 2010*. 2010.

Table 6. Estimated Residential Electricity Rates by Utility

Company Name	Rate (\$/kWh)
United Illuminating	0.24
Fitchburg Gas & Electric Co.	0.20
Connecticut Light & Power Co.	0.20
New Hampshire COOP*	0.20
Commonwealth Electric	0.18
Bangor - Hydro	0.17
Boston Edison	0.17
Public Service Co. of NH	0.17
Narragansett Electric Co.	0.16
W. Massachusetts Electric Co.	0.16
Central Vermont Public Service	0.16
Central Maine Power*	0.15
Unitil Energy Systems Inc	0.15
Massachusetts Electric Co.	0.14
Granite State Electric	0.13
<i>New England Average Bill Amount</i>	<i>0.17</i>

Source: Adjusted from EEI 2010

* Estimated by PSNH.

Electricity bills include charges for electricity generation, transmission and distribution, along with other charges. According to PSNH, the transmission component of their electricity rates constitutes around 10%. Regarding additional transmission development in the North Country, an increase in rates were ratepayers assessed the full cost, as a rough estimate, would approximate 1% to 2% of current average residential electricity rates.⁸² For the typical residential consumer, this might equate to an additional expense of roughly one to two and a half dollars per month.

⁸² This estimate is an approximation based on a 20% carrying charge and average electricity prices and assumes the full cost of the \$150 million estimated transmission cost. This approximation does not necessarily recommend that ratepayers pay for the full cost of transmission. Furthermore, additional details about the actual cost of transmission, allowed recovery rates and which ratepayers would bear the cost would be needed to improve the approximation. However, it shows a sample calculation for approximating a potential increase in rates.

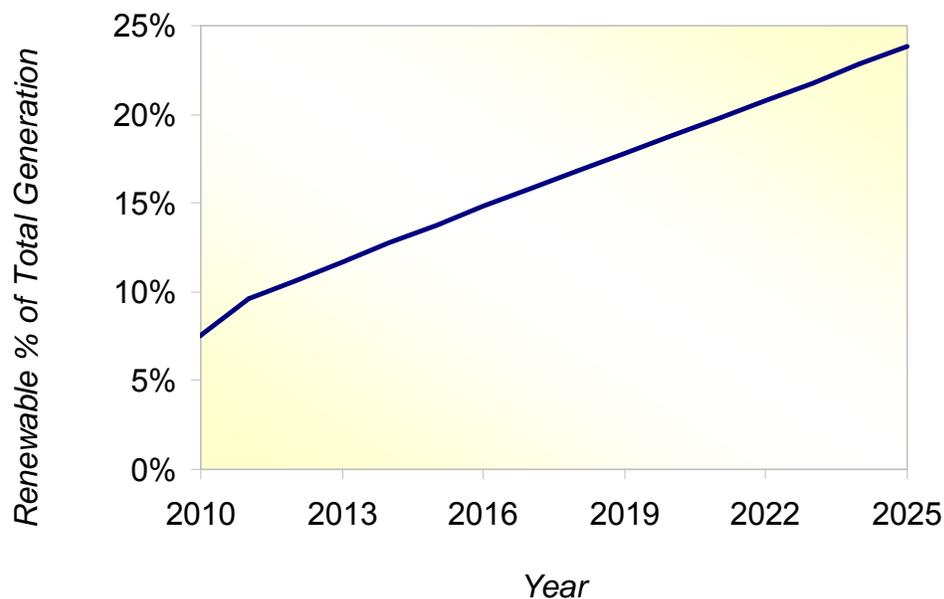
6.1.2 Benefits

There are several potential benefits with transmission development, including its creation of a pathway between renewable energy resources and electricity markets and consumers. Often, renewable generation facilities have immobile fuel sources. As such, transmission is key to getting it to market. The following subsections highlight the potential benefits of transmission development, and the indirect benefits of its enabling renewable resources.

6.1.2.1 Renewable Energy Goals

As noted earlier, New Hampshire law requires each electricity provider to meet customer load by purchasing or acquiring RECs, certificates representing generation from renewable energy based on total megawatt-hours supplied.⁸³ Figure 4 illustrates that standard over time.

Figure 4. New Hampshire Renewable Portfolio Standard Requirements over Time



As part of this requirement, electricity providers can purchase RECs independently of power. Furthermore, electricity providers can purchase RECs originating from outside of the State. In

⁸³ RSA 362-F.

turn, other states with similar requirements to purchase RECs can acquire RECs from within their state or outside of their state.

With regard to transmission development in the North Country, because it enables renewable development within the region it would also have an impact on the supply of RECs available in the region. However, it is uncertain what role these renewables will play, as other regions within New England are developing renewable resources, and associated RECs. Furthermore, RECs will ultimately compete on price, a factor determined by the generator of the REC.

6.1.2.2 State Energy Consumption Goals

As noted in Section 3, in 2006, the Governor set a goal of having 25% of the state's energy requirements be met with renewable sources by 2025.⁸⁴ Towards this goal, in 2009, the State contracted with ConEdison to procure 25% of its energy from wind power over an 11-month period at a cost of \$4.4 million. In 2009, New Hampshire state offices and buildings consumed almost 1,000,000 mmbtu, of which roughly a third was electricity, and spent \$22,484,722, of which electricity costs constituted over 60%.⁸⁵ In theory, the development of transmission could enable the development of renewables in the State, contributing towards its goal of using renewable resources, and doing so with local resources.

6.1.2.3 Economic Development

Many stakeholders have discussed the potential for transmission development to lead to economic revitalization in the North Country. Though the economic impact of transmission development in the North Country is relatively small, the indirect impact through enabling renewable resource development could be sizeable. The following summarizes publicly available information regarding economic impacts from transmission development and the subsequent development of renewable resources.

⁸⁴ Accessible at: online at: http://www.nh.gov/oep/programs/25_x_25/index.htm. Accessed August 25, 2010. Energy requirements include transportation and heating energy and electricity generation.

⁸⁵ New Hampshire State Energy Manager. *State of New Hampshire Energy Management Annual Report for State-Owned Buildings and Fleets: Fiscal Year 2009*. 2009.

Tax Revenue

Industrial and generating facilities pay property taxes to the city or town where the facility is located. In some cases, renewable energy generators may receive local property tax exemptions for certain wind, solar and biomass projects under New Hampshire statute RSA 72:61-72 and some unincorporated areas in Coos County are not subject to property taxes. However, some facilities have opted to pay the city or town, in the form of a Payment in Lieu of Taxes (PILOT), to compensate the local government for some or all property tax lost. According to the New Hampshire Office of Energy and Planning data, 84 cities and towns offer property tax exemptions, which are intended to attract developers that may have otherwise built their facilities elsewhere.

The PILOT payment depends on the facility location, and is a negotiated agreement between generator and local city or town. Developer Noble Environmental Power listed a typical payment of approximately \$5,000 per MW per year for a 15-year contract, and noted a \$21.4 million payment over 15 years for three wind park facilities in Clinton County, New York. In all cases, the PILOT does not exceed what would have been paid in property taxes.

Project developers may also make lease payments to allow the facility to be sited on landowners' property. The amount of most lease payments is confidential, and detailed in private contracts between parties. Lease payments directly benefit the landowner, but add additional indirect benefits to local communities, depending on the land ownership. If the ownership is local or regional, these payments are more likely to stay within the community. This effect of local spending, called the Local Multiplier Effect, exponentially increases the dollars spent on local goods and services. For every \$1 spent locally, \$0.45 is in turn spent within the community compared to \$0.15 on non-local spending.

Jobs

Renewable energy facilities employ a range of occupations in two distinct phases: short-term development and construction and long-term operation and maintenance. The first phase creates the highest employment phase in multi-year development and approximately 1-2 years under construction. When completed, the facility employs fewer workers, but these operations and maintenance positions are permanent and long-term. The proposed power line upgrade is not expected to result in significant job creation, and could be handled by existing employees, depending on the transmission line ownership structure.

Since the ISO-NE interconnection queue contains wind and biomass projects proposed in Coos County, our job creation discussion is limited to these fuel types. Wind and biomass facilities both undergo short term and long term job creation phases but differ in the overall number of positions created. A literature review of existing economic potential impact studies suggest a range of direct jobs created in wind and biomass. For example, biomass estimates range from 234 to 455 jobs created per 1 million tons of wood biomass. Of these jobs, 117-161 are in logging, transportation and plant operation.⁸⁶ The larger the plant, the more woody fuel required, the more jobs are created. Wind generation requires a range of 40 and 160 direct construction jobs per 100 MW of wind construction.⁸⁷

Renewable energy developers hire a mix of locally available and outside services. In practice, this leads to a wide range of local hiring, depending on project location and local workforce skills. For example, estimates of local hiring, with local defined as hiring within a 25-mile radius of the proposed project, is 10 to 20% of total construction hires.⁸⁸ According to a study conducted by the University of New Hampshire, during the wind park construction phase, Noble Environmental Power would likely hire roughly 200 full-time equivalent employees within a 100-mile radius of the project, and 30 FTEs within the Coos County. Following the construction phase, the University projects the full-time employment of 6 permanent local hires.⁸⁹ Permanent local hires for biomass facilities are considerably higher since the wood product fuel must be sourced and transported locally.

Job creation represents a range of occupations, and expertise and wage levels, and varies by generation fuel source. To illustrate, Noble Environmental Power proposed 100 MW wind park in Coos County will generate jobs will employ the following types of occupations⁹⁰:

⁸⁶ Based on a Massachusetts study (Timmons et al 2007) biomass electricity plants using 1 million tons of wood biomass per year.

⁸⁷ R. Gittell, J.R Carter, and M. Magnusson, *Economic Impact of Granite Reliable Power Wind Power Project in Coos County, New Hampshire*, University of New Hampshire Whittemore School of Business and Economics, February 2009.

⁸⁸ Ibid. Number is according to Coos County contractors surveyed.

⁸⁹ Ibid. Based on project data provided by GRP and review of other wind power project projects and documentation which indicates 6-10 permanent operations and maintenance jobs per 100 MW.

⁹⁰ Accessible online at: <http://www.noblepower.com/faqs/wind-energy-economy.html#three>.

- **Pre-development and development phase:** Project developers; Field engineers; Environmental managers and consultants; Legal and permitting support; Community outreach; Document control; Administrative and office support
- **Construction phase:** jobs created include all of the above, plus construction-related positions; Transportation managers; Contract and sub-contract managers; Project controls engineers; QA/QC technicians; safety technicians
- **Operational phase:** Project managers; Project coordinators; Production managers; Wind turbine technicians; Wind turbine maintenance; Administrative and office support

These positions average an estimated annual wage of \$45,000 per year, significantly higher than the Coos County 2008 average wage of \$30,500, according to Noble. These direct jobs effects have the potential to create additional rounds of economic activity through indirect jobs, such as contracted services not directly employed by the developer, and *induced effects* that result from increased regional employment. These effects are typically housing and household goods and services, many of which are purchased locally.

Coos County Jobs Impacts

As of the October 2010, the ISO-NE generator interconnection queue included approximately 230 MW of renewable generation projects in Coos County. While the total job impact in Coos County is unknown because the renewable energy projects are still in development, developers have released some data to show potential job creation. For example, Granite Reliable Power reported spending \$4 million development costs as of 2007. Of that, 40% or \$1.6 million was spent on Coos County goods and services, and an additional 20% in other New Hampshire counties on civil engineering, surveying, wetland scientists, and related permitting services.

For all jobs created locally, impact on the local community is considerable since more of these wages are likely to stay within and circulate among local businesses. According to the Institute for Local Self Reliance data, for every \$1 spent locally, \$0.45 is spent locally compared to \$0.15 for every \$1 spent on corporate goods.⁹¹

⁹¹ Vellequette, Larry. *Toledo Blade*, Economic Slump Lifts Buy Local Movement: Dollars Stay in Area, Have More Impact, December 19, 2009. Accessed August 15, 2010 at: <http://www.toledoblade.com/apps/pbcs.dll/article?AID=/20091213/BUSINESS03/912139999>

6.1.2.4 Reliability Benefits

Electric reliability benefits refer to improvements in electricity service related to improvements in power quality, the reduction in outage durations, or the avoidance or reduction of electricity outage frequencies. Improved reliability can attract or retain businesses and jobs, and local governments can benefit from reduced burden on local fire, police and other city services that assist during blackouts. Because the Coos Loop has a limited impact on the larger electricity grid, upgrades to the system are not likely to have reliability benefits for the larger system. Rather, any improvements in reliability would be local.

In summary, as we have discussed in this section, facilitating the development and integration of North Country renewable energy resources would or could:

1. Contribute to meeting State goals for renewable energy generation and consumption
2. Contribute to the economic revitalization of the North Country through the:
 - a. Payment of property taxes, Payments in Lieu of Taxes, or lease payments; and
 - b. Addition of both temporary and permanent jobs for plant construction, operation and maintenance.

While these benefits are difficult to quantify with precision, they could be positive elements contributing to the long-term economic growth of the region.

7. Framework for an Action Plan

This section outlines a framework for an action plan to pay for transmission upgrades to integrate 400 MW of renewable generation in the North Country. As discussed earlier, several options exist for allocating costs to develop transmission in the North Country. The following is one approach which the analysts believe has a high probability of success in northern New Hampshire. In addition, as the approach considers cost assignments outside of the ISO-NE Tariff, it may also be useful for stimulating renewable development in other parts of the State.

7.1 Proposed Framework for an Action Plan

The proposal to allocate costs for transmission development in the North Country would use the existing ISO-NE framework of allocating transmission costs to renewable energy developers, but would also take additional measures to remove barriers currently impeding transmission development. In short, at its base it is a modified direct assignment approach designed to reduce development barriers. (See discussion of direct assignment approaches in Section 4). As such, 100% of the transmission costs are allocated to renewable energy developers. However, where the State felt that it was important to have a renewable generation project move forward and where it felt that additional support would be needed to make a project financially viable, the State could build on this base and choose to provide financial support to renewable energy developers. This support could take the form of a direct transmission-related subsidy, or take the form of other incentives not directly tied to transmission. As such, a renewable energy developer might receive a net subsidy under this plan. In either case, the ability of this plan to fit within the existing ISO-NE cost allocation framework simplifies the approval process and places the timeframe for approval squarely in the hands of the State. Furthermore, the modification it offers to reduce development barriers means that it fits within the State's goals to promote transmission and renewable energy development in the State.⁹² (See Section 3, above, for additional discussion on State goals and actions regarding renewable energy). Additionally, optional provisions could ensure local benefits from the development which would help garner support and address needs for economic revitalization. Overall, the

⁹² The plan does not address stakeholder concerns with renewable development, as it is outside of the scope of this assignment. However, it appears that additional measures could be taken to help address stakeholder concerns about the types and size of renewable development in the North Country. Furthermore, KEMA believes that such measures would not interfere with the cost allocation framework recommended by this study.

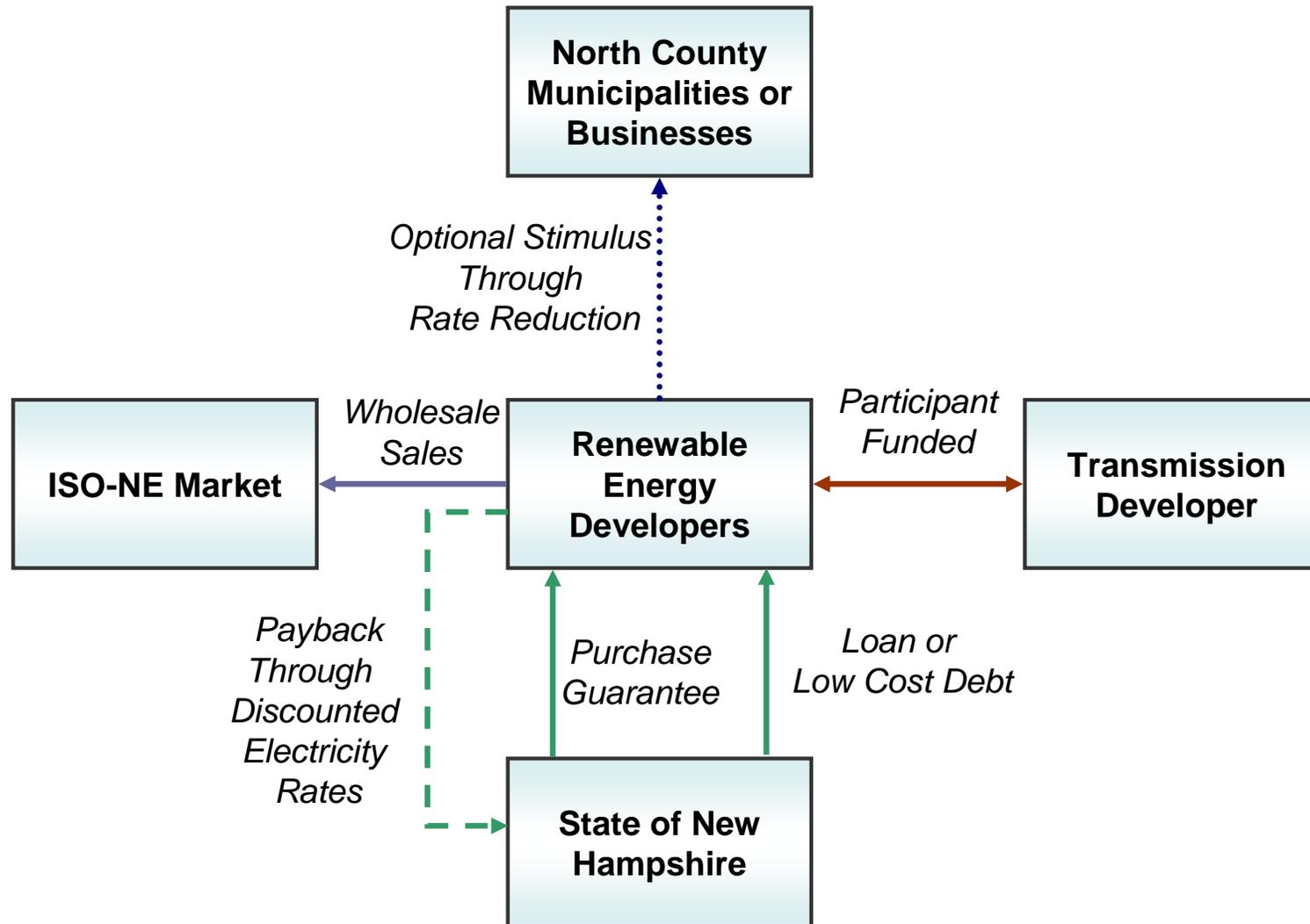
proposed framework for an action plan provides a flexible framework under which stakeholders can negotiate successful ways to promote transmission development while meeting State and local goals.

7.2 Approach Description

The primary mechanisms to help stimulate renewable energy development are a State-funded loan and a purchase power agreement (PPA). The use of a PPA helps to reduce project risk for developers by securing the sale of plant production over an extended time period. The intent is to reduce the cost of capital and promote more favorable debt service requirements. Any loans, or subsidies, would then be paid back to the State over time through discounted electricity rates. The intent is to provide a predictable renewable energy source for the State, funded out of an identifiable and capped budget item. Overall, this approach would address current barriers to development and align with current State initiatives to reduce fossil fuel energy usage. Furthermore, because ratepayers do not bear the burden of project costs or risks, the approval process would be limited to the NHPUC and the State government.

Figure 5 depicts the basic framework for this cost allocation methodology. Specifically, the State would provide an up-front loan or low-cost debt to renewable energy developers to assist with project financing. In addition, the State would make a commitment to procure power from the renewable energy developers, with the stipulation that it would then receive electricity at a rate lower than the current generation component of the retail rate paid by the State. Over time, through these reduced rate energy purchases, the State would recover the value of its payments to the renewable energy developers. The renewable energy developers would remain subject to the ISO-NE Tariff provisions of Schedule 22 or 23 and request a full deliverability generation interconnection study. By providing up-front funding and offering a commitment to purchase their product, this approach is intended to ease the financing burden of renewable energy developers. In addition, the approach would better assure the transmission developer that renewable energy developers will in fact connect to the system they develop. Because the State would recover its “up-front” costs over time, it would be paid back its investment. Such commitments would help the State meet its goal to procure more renewable energy and promote renewable energy development in the State. To ensure local benefits are reaped from the renewable energy development, and to promote support for the proposal within the North Country, the State could further decide to offer reduced electricity rates to the Coos County municipalities.

Figure 5. Recommended Action Plan Framework



7.3 Implementation Flexibility

The plan proposes a flexible approach to transmission cost allocation within the proposed framework. In particular, it proposes using a variety of financial tools as necessary to move the plan forward. In other words, where support is difficult to garner, alternative approaches may be viable. In addition, the plan does not propose a specific loan payback time or percent interest and it does not specify what electricity rates should be agreed to in a PPA. This is because the State must determine the amount of risk it is willing to bear, and the amount of financial incentives it wants to provide to renewable energy developers to promote clean energy in the region. Furthermore, information about the finances of renewable developers is not generally publicly available and has been difficult to assess in many cases. As generalizations are difficult to apply, this report urges the State or a separate entity to assess what minimum funding, in conjunction with PPAs, would be needed to enable development. As such, the plan proposes negotiating terms according to the cases of individual developers and suggests processes for developing these terms. The following discusses potential variations on the basic approach, highlighting where variations could address potential obstacles.

Engagement Agreements among Parties

Functionally, this cost allocation approach could be implemented a number of ways. Two ways are described here. In both, a Load Serving Entity (LSE) would contract to provide renewable power to State office buildings. Also, the renewable developer would negotiate transmission agreements with the transmission developer. In addition, if this generation also required upgrades to existing transmission facilities an additional agreement would have to be reached with the owner of those facilities. Other charges might also be required depending on where the line terminates. In one approach, however, the State would negotiate a PPA directly with the renewable energy generators and the LSEs would have the obligation to deliver power purchased by the State and provide other supplemental services to deliver firm power to the State. The LSE's would then recover their costs through their usual tariff. Any added energy delivered by the LSE could be charged at a fixed rate, adjusted according to the proportion of energy the LSE passes on from the renewable energy developer at a discounted rate, or set at a lump sum amount.

Alternatively, the State could negotiate a "State Government" tariff for an electricity rate below current rates charged to the State. Concurrently, the LSE would negotiate a PPA with the renewable generators. As before, the renewable energy generators would negotiate an agreement with transmission developer, with other agreements and charges possibly required,

depending on the construction of the lines. To facilitate tracking of loan recovery through power purchases, the State could purchase the energy as a lump sum amount.

Identifying Developers

To be equitable, a general offer to negotiate a PPA should be made available to any new developer that would want to connect in northern New Hampshire, though individual loans may vary according to the renewable developer's financial circumstances. As of October 2010, the ISO-NE generator interconnection queue included approximately 230 MW of renewable generation projects in Coos County – this includes projects proposing to connect to both the local distribution and regional transmission systems.⁹³ However, additional renewable developers may also seek to connect to the transmission system. As such, the State should consider ways to assess the amount of likely, developable renewable energy capacity which the transmission development could interconnect. A simple approach would be to provide a timeline over which interested parties could register their interest. This would also help provide a better sense of the types of upgrades to the transmission system might require. An approach that requires more commitment on the part of the developer, such as used by BPA where developers require deposit payments to ensure a minimum level of commitment, could be employed to further gauge the seriousness of intent. Concurrent identification of potential developers could benefit the project by allowing the transmission developer to subscribe larger portions of the line, thus reducing the transmission developer's risk.

Addressing Potentially Limited Funds

As the approach requires repayment to the State and couches it within the State's energy cost budget, the State could fund only a limited number of projects before the payback on investment becomes too great. The limiting factor is the State's projected load, as the State's ability to recover its costs depends on the ability to receive discounted energy. With the State's energy needs already met, it cannot offer additional financing through this payback mechanism. To address this issue, and to be equitable, the renewable energy developers should make the same offering of reduced rates for up-front funding or power purchase commitments to other parties who want to invest similarly.

⁹³ The ISO-NE generator interconnection queue is dynamic with projects continually entering and exiting for a number of reasons. Accordingly, the ISO-NE updates and posts the queue monthly to its website at http://www.iso-ne.com/genrtion_resrcs/nwngen_inter/status/index.html.

Transmission Authority and Bonding Financing.

The implementation approach to financing the transmission upgrade is flexible. Where the state cannot easily procure up-front funds, it might consider using other financing tools as have been employed by transmission authorizes, such as state bonds.

In particular, the State could directly finance bonds, or indirectly finance them through a separate agency, for the development of projects. Consistent with the approach of many states with transmission authorities, the State could issue bonds through a separate entity other than the State, allowing bond liabilities to be that of the entity and not of the State.

Forming a transmission authority to issue bonds has been successful in states such as Wyoming. For example, the Wyoming Infrastructure Authority is governed by a five member Board of Directors appointed by the Governor, and may issue up to \$1 billion of revenue bonds to finance projects. Typically, this entity is separate from, but may share resources, with government entities, and contains a mix of political appointees and other staff. Transmission authorities vary in scope, and may develop transmission or also take on broader goals to promote statewide energy development opportunities.

The potential disadvantage of bonding through a new authority, however, is that a new transmission authority might not have a credit history unless it is directly tied to the State. Further, the State would need to decide on what restrictions it would put on owning the transmission facilities. Some transmission authorities, for example, divest them as soon as they become economic, and others are able to own the transmission investments but must lease them. Alternatively, the State could use existing authorities, such as those similar to the Community Development Finance Authority, or issue the bonds directly in a separate process. In addition, using an approach from states with transmission authorities, the State could lower the cost of debt by making the bonds tax exempt. Current efforts are underway by several transmission authorities to seek federal tax exemption for such bonds.

Transmission Development Options

According to FERC's tentative guidelines put forth in its June 17th NOPR, the transmission developer could be either an incumbent or a non-incumbent. Because an incumbent has access to and ownership of existing rights of way, it is feasible that the incumbent would have different costs and risks associated with the transmission development. Either way, revenues could be recovered through a cost-based approach or other cost recovery mechanism approved

by FERC. The project would have to meet certain FERC criteria. In either case, it is likely that the transmission would be turned over for ISO-NE operation.

Electricity Pricing in PPAs

Ultimately, the success of the basic approach would rely on the ability and willingness of the developers to provide below-market rates. In some cases, a renewable developer may not be able to offer an electricity rate lower than the prevailing market price, even where measures to reduce risk have reduced the cost of capital. Such cases might exist where transmission interconnection costs become a significantly large proportion of the total costs or where other operating costs are significant. Where the state feels that it is important to encourage these renewable investments for purposes of meeting RPS goals or economic development goals, the State could choose to subsidize development and not recoup all of the costs of its investments from rates. Alternatively, the State could elect to negotiate a generation rate at a higher-than market value. To help evaluate what costs are reasonable, the State could use, as a baseline, other prices it has paid to procure renewable energy. In addition, the State could choose to require that the loan be paid back in installments to circumvent the payback mechanism that relies on reduced electricity rates.

7.4 Sensitivity of Approach to Costs

As a sensitivity, researchers were asked to examine how the proposed transmission cost allocation framework might change if upgrades were ten or twenty percent above or below the estimated \$150 million cost. Researchers believe that a small variation in the cost of transmission, including variations on the order of 10 to 20%, would not change the recommended framework as presented in section 7.2.

However, researchers believe that the use of proposed mechanisms in accordance with the recommended framework could depend on a number of factors, including the State's projected energy consumption, renewable energy developers' prices to produce, and the cost of the transmission upgrade. Where development costs exceed the amount the State is able to provide and have a reasonable payback period, other approaches such as State or private bonds could help. As such, significant increases or decreases in transmission costs could potentially affect what combination of approaches the State pursues under the proposed framework.

Information about the finances of renewable developers is not generally publicly available and is difficult to assess in many cases. Furthermore, generalizations are difficult to apply. As such,

the State or a separate entity such as a transmission authority would need to assess what minimum funding, in conjunction with PPAs, would be needed to enable development. Furthermore, a complete assessment of the State's energy use would be required to determine the amount of money that could be loaned up front with a reasonable payback period. In order to maximize the advantage of using a PPA, and limit the financial burden to developers, this process should be a streamlined one which does not add notable cost to the participating developer.

7.5 Distribution of Costs and Benefits

Transparency in renewable developer financing is key to assessing the needs of developers. In particular, the intent is to provide enough support to overcome development barriers. Support beyond this would expend funds not fulfilling their purpose. Assessing developers' needs is particularly important as the situation of developers can be quite varied, and as the cost to connect resources can vary by the amount of resources connecting.⁹⁴ In addition, in some cases, the generator connecting just after another could face lower interconnection costs due to upgrades made by the former.

With regard to the costs and benefits of the proposed approach, the renewable energy developer would benefit by having lower barriers to investment. However, to the extent that a developer already had a PPA commitment, that developer would be ineligible to participate in a mechanism that repays through reduced rates. In such cases, low-cost debt could be provided if it was determined to be needed. All developers receiving such assistance, however, would have to pay back the funds over time, unless the State decided that for policy reasons, it wanted to subsidize the developer to promote renewable development in the State. In the case where the State chose to subsidize a developer to make it financially viable, either through direct loans or an agreement to pay higher-than-market rates for example, the generator would receive an incremental benefit beyond the risk reduction of the base cost allocation measures.

Transmission developers benefit from this approach by gaining a clearer understanding of the demand for their assets and by having an increased confidence that power developers will want to connect. Typically, they would be expected to finance the cost of transmission, and be engaged in the development, design and construction processes.

⁹⁴ For example, the \$/MW connected varies as MWs connected increases.

The State would benefit by being able to meet its goals for renewable development in the North Country on a timescale it could influence directly. In particular, it would secure predictable sources of renewable energy to help it meet its goal of 25% clean energy by 2025, and it would assure that the renewable power developed to help meet regional RPS goals are located within the State. While at its base, the State would not pay directly for these benefits, the State, however, would bear a risk regarding the payback of its investments. The State could help lower that risk, by assessing the commitment of developers in a variety of ways. Furthermore, the framework is flexible such that the State could chose to subsidize the development of renewable energy projects.

The North Country could potentially benefit with cheaper electricity rates. They may also benefit from jobs and new tax revenue associated with the projects. Though some stakeholders have concerns about the impact of larger-scale renewable development in the community, the selection of renewable projects and implementation requirements could potentially limit some of these concerns. The authors believe, however, that while these concerns should be recognized, the processes to address them should be separate from the development of a transmission cost allocation.

7.6 Implementation Steps & Recommended Parties

The following highlights steps toward implementation of the proposed cost allocation methodology. Several steps could occur concurrently.

- Commission further studies on State energy usage and acceptable payback periods to assess how much the State could loan using a mechanism paid back through energy consumption.
 - Several parties could potentially lead this effort, from the State Legislature to the PUC or OEP, for example.
- Develop a process to assess developer demand for transmission capacity.
 - Again, a State agency representative, the NCTC, or a transmission authority would be appropriate for this task.
- Develop a process to assess the financial needs of potential renewable energy developers to help the State guide what terms of agreement are appropriate, and whether or not the State will ultimately provide financial incentives to the renewable energy developers in addition to assuming up front risks.
 - A State agency representative, the NCTC, or a transmission authority would be appropriate for this task.

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- Care should be taking in designing this process so that the burden for developers to participate does not add to financing costs.
 - Design and cost out an appropriate upgrade for the transmission system.
 - Transmission developers and renewable developers would be the primary stakeholders engaged in this process
 - Develop and pass required legislation, as discussed in the subsequent section.
 - The State Legislature would need to work with the NCTC and others to craft legislation appropriate for enabling this cost allocation methodology. Authorization of bonds or appropriation of loan funds are key.
 - Negotiate PPA, terms of low-debt financing, and electricity rates. File details of proposal with FERC.
 - The State would either negotiate terms directly with the renewable energy generators or through a Load Serving Entity. The New Hampshire State Energy Manager’s knowledge of State office’s energy consumption and expenditures would likely come in helpful for this task. The State should, when practical and appropriate, consult with both FERC and ISO-NE regarding procedural and technical questions it may have associated with resource and transmission interconnection.⁹⁵
 - Negotiate long-term bilateral agreements for firm transmission rights.
 - Renewable energy generators and transmission developers would need to undertake this task. Early discussions with FERC and ISO-NE would be important.
 - Construct the transmission and eventually turn over operation to ISO-NE.
 - The transmission developers and ISO-NE would be engaged in this task.

7.7 Implementation Timeline

The timeline for implementation of this approach would depend on a number of factors. In particular, State load studies, budget allocations and negotiations for PPAs with renewable power developers would all need to occur. In addition, renewable generators would need to

⁹⁵ FERC would lack jurisdiction over a state-based proposal to provide up-front funding for the transmission enhancements, and its recovery of its investment through below-market power charges. However, both the power sale agreement and the generator interconnection agreement between the project developer and the transmission provider would be subject to FERC jurisdiction.

coordinate with transmission developers to negotiate appropriate transmission design and to negotiate transmission service agreements. Additional time would be needed to set up a third party, such as a transmission infrastructure authority, to facilitate negotiations should the State decide to develop such an organization.

Just as transmission projects vary in scope, the time to complete a transmission project can also vary greatly, and depends on a number of factors. In particular, planning, siting, licensing and construction are all stages in the development of transmission. As such, major transmission projects can take five to ten years or more to complete the entire process from siting to operation.

7.8 Proposed Legislative Needs

The following highlights legislative needs to move the proposal forward.

- Develop rules and eligibility for state or municipal bonds and assign authority for bonds associated with renewable energy developments in Northern New Hampshire.
 - Examples for the development of tax-exempt bonds exist in several states, as does the establishment of authorities to issue bonds, outside of traditional state functions.
 - With regard to state or municipal-issued bonds, New Hampshire has several mechanisms in place which could be considered. For example, the New Hampshire Municipal Bond Bank has issued bonds for a number of capital projects, while the State Treasury has done the same for state-issued bonds. For the latter, the Treasury must be authorized law to issue debt.
- Establish a transmission authority, if desired, and outline its authority and responsibilities.
 - Examples of legislation establishing transmission authorities exist in numerous states.
- Appropriate funds to make up-front loans (or other subsidies) to renewable developers.
- Integrate tracking of loan repayments through energy purchases. The State could make use of the existing energy tracking system in place developed to assist the State meet its goal to reduce consumption in government buildings by 10%.

8. Alternative Approaches

In addition to the recommended framework for an action plan outlined above, some stakeholders requested that the report elaborate on how to implement other transmission cost allocation methodologies. In particular, there was a desire to understand how ratepayers might be engaged to support transmission cost allocation. As such, the following section highlights two frameworks for ratepayer involvement. One engages ratepayer support to promote transmission development indirectly, through support of renewable energy developers, in a fashion similar to the framework recommended in Section 7. The other engages ratepayer support to directly address transmission development, either through bearing up-front risk or through direct contributions to the cost of transmission.

8.1 Alternatives to Promote Renewable Energy Development

In a manner similar to the proposed framework of an action plan outlined in Section 7, this framework would indirectly support transmission development by promoting the economic viability of renewable energy developers in the State. However, this financial support would be derived from ratepayers rather than the State. Specifically, this method would use a similar direct assignment cost allocation method, but would subsidize renewable energy developers via a ratepayer-based mechanism. The proposal would adhere to the existing ISO-NE framework of allocating transmission costs to renewable energy developers. Involvement by the State, or a State-authorized authority, would likely be required to coordinate this approach.

Approach Description

Examples of promoting renewable energy development via ratepayer mechanisms already exist in New England states. For example, Maine includes renewable energy as a part of its standard offer procurement process.^{96,97} In addition, Vermont has implemented a program entitled the

⁹⁶ New England States Committee on Electricity, Report to the New England Governors on Coordinated Renewable Procurement: Identifying cost-effective, clean energy resources through competitive processes, July 2010.

⁹⁷ In New Hampshire, PSNH is required by statute to supply all default service offered in its retail electric service territory from its generation assets and through supplemental power purchases, subject to NHPUC approval. Though it is subject to the State's RPS, it not required to procure renewables as part of its requirement to provide default service.

Sustainability Priced Energy Development Program (SPEED) which is intended to provide incentives for development of selected renewable energy resources. Under this program, the Vermont Public Service Board establishes default prices for a standard offer to purchase electricity from specified renewable energy resources. These default prices are above-market prices.

Power sold by developers under the SPEED program is sold to Vermont Electric Power Producers, Inc., (VEPPI) which is a state-owned corporation established for the purpose of purchasing such electricity. Electricity purchased by VEPPI is resold to each of the utilities in Vermont based on its respective load ratio share. Each of the electric utilities in Vermont is required to participate in this program. The costs of such power purchases are then “passed through” by the utilities to their retail electric service customers. The effect of this program is to spread the costs of electricity supplied by the favored renewable energy developers across all ratepayers in the state, rather than imposing the costs on the customers of any specific utility. The Vermont program includes not only IOUs, but also the rural electric cooperatives and municipal utility systems.

Adoption of a program similar to SPEED program in Vermont might help to facilitate payment for the cost of transmission upgrades in the North Country. In particular, the NHPUC could set the default offer prices at a level that would be sufficient to encourage renewable energy developers to go forward with their projects after consideration of the cost of transmission enhancements for which they would be responsible. Such prices should therefore be sufficient to offset the additional costs to project developers of paying for enhancement of the Coos Loop. The effect of such a program is to spread the costs of electricity supplied by developers of new renewable energy resources in Coos County across all ratepayers in the state, rather than imposing the costs on the customers of any specific utility. Such an approach would align with New Hampshire’s stated policy to promote development of renewable energy resources in Coos County.

Because an approach similar to that in Vermont is neutral with regard to renewable resources across the state (e.g., it does not favor renewables in any particular region), additional studies might be done to gauge where the likely renewable development would occur. This would help gauge the amount of transmission line capacity that developers might subscribe to in the North Country. Further, such studies could be developed from existing renewable research conducted by ISO-NE. New Hampshire involvement in the design and costing of an appropriate upgrade for the transmission system, like the Texas PUC’s involvement in transmission development, could increase transparency in the costs and design of the needed transmission upgrades.

Sensitivity of Approach to Costs

The recommended approach would depend on a number of factors, including renewable energy developers' prices to produce and the cost of required transmission upgrades. The State, or a separate entity such as a transmission authority, would need to assess what minimum incremental financial support would be appropriate to promote renewable generation development in the State. Average market prices or prior procurements by the State could be a starting point for determining appropriate default prices.

Distribution of Costs and Benefits

With regard to the costs and benefits of the proposed approach, the developer would benefit by receiving financial support to promote economic viability, accounting for transmission costs. Because the approach is 'blind' to individual generators, and because generator costs vary due to a number of factors, some renewable generators may benefit more than others. Transmission developers benefit from this approach by gaining a clearer understanding of the demand for their assets and by having an increased confidence that other power developers would also want to connect. The State would benefit by being able to meet its goals for renewable development on a timescale it could influence directly. Ratepayer electricity rates would likely increase as a result.

Implementation Steps

The following highlights steps toward implementation of the proposed cost allocation methodology. Several steps could occur concurrently:

- Develop a process to assess the financial needs of potential renewable energy developers
- Commission further studies to assess appropriate prices for default service.
- Develop a process to assess developer demand for transmission capacity.
- Design and "cost out" an appropriate upgrade for the transmission system.
- Develop and pass required legislation, as discussed in the subsequent section.

Proposed Legislative Needs

The laws outlining requirements for default service would need modification. Furthermore, additional legislation might be needed should policymakers decide to establish a state-owned

corporation to handle electricity purchases. (It is feasible that the State might use existing agencies to conduct this process).

8.2 CAISO Approach

Another cost allocation alternative that would take a more direct approach to allocating costs for transmission development is an approach based on CAISO's rate for location-constrained resource interconnection facilities (LCRIF). Implementing an approach in New Hampshire like that for remote resources in CAISO, could limit the burden on ratepayers, both by making the burden temporary and also by limiting the amount of any costs covered by ratepayers. This approach would require a modification to the ISO-NE Tariff and require approval by FERC. Furthermore, it would require determining which ratepayers in the State would initially cover the cost of transmission development, and whether they would cover these costs in part or in full.⁹⁸

Approach Description

The intent of the CAISO approach is to lower barriers to the development of remote renewable resources while limiting ratepayer impacts to ensure that rates are just, reasonable and not unduly discriminatory. A modified approach implemented in New Hampshire could potentially do the same. The proposal could allocate transmission costs across ratepayers within the State

In particular, as noted earlier, the ISO-NE Tariff contains provisions for transmission over local transmission facilities (LTFs). Electricity rate adjustments associated with upgrades to the Coos Loop would likely go into the appropriate provider's Local Service Schedule, and be recovered by the users of their system.⁹⁹ Another example is a subpart of the Northeast Utilities tariff that

⁹⁸ As a rough approximation, the potential cost to ratepayers for a transmission development cost equal to \$150 million would be an increase in electricity rates of around 0.002 \$/kWh to 0.003 \$/kWh, which would vary depending on the actual cost of transmission, which ratepayers would cover the costs, and what rates were approved to be recovered. In addition, this amount could be reduced where other partners, such as the State, private bonds or developers helped cover the transmission development cost.

⁹⁹ The appropriate entity would depend on who owns the transmission system, and which rates the costs are allocated from.

relates specifically to Connecticut for coverage of localized PTF transmission development¹⁰⁰. By isolating a sub-group of ratepayers, the rest of New England does not cover these costs.

The revisions would have ratepayers cover transmission development costs until power developers come online. In addition, ratepayers would cover only the costs of any unsubscribed portion of the line until the line is fully subscribed. In following the approach used by CAISO, each generator that interconnects would be responsible for paying its pro-rata share of the going-forward costs of the line. Alternative ratios are feasible should the State determine another method would be appropriate. In general, however, the interconnection costs would be recovered through a charge to load until generators are interconnected. If the State found that it was appropriate to promote certain renewable energy projects which would otherwise be unable to cover their full costs, the State could decide to subsidize these developers in other ways, or to have ratepayers bear a component of the associated transmission costs permanently.

To be eligible for the remote resources rate treatment, the transmission development should be approved by the NHPUC. Similar to the CAISO process, once a facility was constructed, generators of any fuel type would be eligible to interconnect and contract for unsubscribed capacity.

Similarly, the approach should include mechanisms to protect ratepayers. These might include a rate impact cap and a requirement that before transmission is developed, remote renewable energy developers have expressed a sufficient level of interest in subscribing to the line. The State or a state-authorized authority could either hold the transmission owner responsible for demonstrating this, or could directly manage the process for assuring commitments.

Sensitivity of Approach to Costs

Under a pure CAISO approach, generators would bear the full cost of the transmission development and ratepayers would bear the up-front risk of the project through higher electricity rates. Where the ratepayer risk is deemed too large, the up-front contribution by ratepayers

¹⁰⁰ The “Localized Cost Responsibility Agreement(s)” refer to costs associated with a reliability upgrade that exceed ISO-NE’s reliability requirements due to aesthetic or other non-reliability related cost approved in the state siting process. The incremental cost associated therewith are not regionalized, but instead are allocated to the local area where such costs were incurred pursuant to a FERC filed agreement.

might be lowered. Where it was determined that generators would not be able to bear the long-term costs of transmission development, a portion of the up-front ratepayer contribution might be made permanent (e.g., generators would pay back a portion of the cost, rather than the entire cost).

Distribution of Costs and Benefits

With regard to the costs and benefits of the proposed approach, the transmission developer would benefit by having lower barriers to investment. Renewable energy developers benefit from this approach by providing the certainty that they can deliver their product. The State would benefit as the transmission development could help the state with its goals for renewable development. The costs and benefits to ratepayers would be those outlined as the indirect effects of renewable energy development, though they would bear the risk up front.

Implementation Steps

In implementing a rate-based cost allocation approach, the cost allocation mechanism must specify the ratepayers from whom the costs would be recovered. In particular, there are multiple electricity providers operating in the State, and all or some of the cost could be distributed across the customers of these providers. Implementing a state-level approach, for example, would entail collecting funds from state ratepayers to pay for transmission until power developers were to later come online. In addition, implementing an approach to transmission cost allocation in NH that is similar to CAISO would require a change to the ISO-NE Tariff and would require approval by FERC.

The following highlights steps toward implementation of the proposed cost allocation methodology. Several steps could occur concurrently:

- Develop a method by which to ensure commitments for subscribing to the line.
- Determine which ratepayers should bear the up-front costs for transmission development
- Submit filings with ISO-NE and FERC to modify the tariff
- Develop and pass required legislation.

Proposed Legislative Needs

Legislation might be passed to provide guidance to the NHPUC regarding this approach, such as rate caps.

Glossary of Terms and Definitions

List of Acronyms

AC	Alternating current	an electric current that reverses its direction of flow at regularly recurring intervals
ACP	Alternative compliance payments	Payments made by load serving entities subject to RPS requirements, in lieu of purchasing RECs.
DC	Direct current	an electric current that flows in one direction
FERC	Federal Energy Regulatory Commission	an independent regulatory agency within the Department of Energy that has authority over charges and terms of use of transmission lines
HVDC	High Voltage Direct Current	a high voltage DC transmission line
ISO, RTO	Independent System Operator, Regional Transmission Organization	Independent, federally regulated organizations established to coordinate regional transmission and ensure the safety and reliability of the electricity system. ISOs differ from RTOs in their status requirements.
ISO-NE	ISO New England	The ISO/RTO which operates the electric transmission system for the six New England states
kWh	Kilowatt-Hour	Measure of electrical energy
kV	Kilovolt	Measure of voltage (1 kV = 1,000 V)
NCTC	North Country Transmission Commission	created by legislature to recommend best way to upgrade or expand the Coos Loop
NHPUC	New Hampshire Public Utilities Commission	has authority over utilities in NH, limited role with transmission issues
NTTG	Northern Tier Transmission Group	Group of transmission providers serving customers in the U.S. Western and Mountain states of WA, OR, CA, MT, ID, NV, WY, UT, AZ,
REC	Renewable Energy Certificate	Tradable certificates indicating proof that a megawatt-hour of electricity has been generated from an eligible renewable energy resource.
RPS	Renewable Portfolio Standard	The requirement that an electricity provider generate or purchase a certain percentage of the power it supplies or sells from renewable energy resources.

SEC Site Evaluation Committee

made up of NH government officials, has authority to approve new electric generation and transmission

Other Definitions

Distribution Lines

Power lines that take power from the transmission system to the end use customer. Distribution lines are generally lower voltage than transmission lines.

Economic Study

The legislature-mandated study of the best way to allocate the cost to expand Coos Loop to carry another 400 MW of renewable power.

Electric Load (or Load)

The amount of electric power consumed by (or delivered to) customers at specific locations on the electric grid.

Interconnection

“The facilities used to connect two power systems; those systems can be two individual control areas or between a generator and a control area.”

Minimum Interconnection Standards

The requirements for connecting new generation into the transmission lines. These are set by ISO-NE and FERC.

Power

The rate of production, consumption or transfer of electricity. It is measured in watts. One kilowatt (kW) is equal to one-thousand watts and one megawatt (MW) is equal to one million watts.

Right of Way

The legal right to use and service land along which a transmission line is located.

Transmission cost allocation

An approach to sharing costs among various stakeholders to upgrade a transmission system.

Transmission line

Take power from generation sites on the electric grid to distribution points.

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