

VERMONT UTILITIES STUDY OF NEW GENERATION ALTERNATIVES

PHASE 2 REPORT



Prepared by:



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EXECUTIVE SUMMARY

In an effort to explore options for addressing the Vermont's long-term electricity needs, a consortium of Vermont utilities¹, working in collaboration with the Vermont Department of Public Service, initiated a two-phased study of the costs, infrastructure, and permitting requirements for siting and constructing new generation facilities in Vermont. Phase 1 of the study, completed in January 2008, examines potential generation technologies, their costs, and possible financing structures. Phase 2 examines electric transmission, other infrastructure, and regulatory issues related to siting new generation². Results of the study are summarized below.

Infrastructure Constraints

- Siting new generation, particularly on a large scale, must consider the limits of the state's existing electric and gas transmission and distribution systems. New generation that is located a significant distance from existing transmission and distribution corridors could face infrastructure and permitting expenses that reduce cost-competitiveness relative to power purchase alternatives from within the region.
- Existing generation sites or compatible industrial sites can be far less costly to develop due to proximity to existing infrastructure such as roads, storage tanks, rail lines, and transmission; consistency with existing land use and local development patterns; and lower probabilities of encountering unknown or sensitive environmental resource issues.
- The Vermont Gas Systems (VGS) system could accommodate (or be upgraded to accommodate) substantial gas-fired generating capacity. The required costs (and, therefore, the economic viability of new gas-fired capacity) would depend on the extent of system upgrades, if any, required within Vermont, and on the TransCanada Pipeline ("TCPL") gas transmission system which supplies Vermont. The required upgrades would depend greatly on the size of the power plant, its location relative to the existing VGS system, and whether the plant required firm year-round gas supply or (alternatively) could use oil as a backup fuel during times of high gas demand.

Size and Reliability

- Addressing Vermont's supply gap with one large plant could achieve some economies of scale with respect to capital costs and operating costs, but could also increase the risk of the state's portfolio by relying heavily on one resource. Building a series of smaller generation facilities, although potentially more costly under normal operating conditions, may be preferred since this strategy may enhance the diversity of Vermont's generation portfolio.
- Strategic siting of smaller combined cycle combustion turbines (with total plant capacity on the magnitude of 100 to 200 MW as opposed to the 560 MW capacity plant evaluated in the Phase 1 Report) could significantly reduce regulatory costs and risks by avoiding major transmission investments.

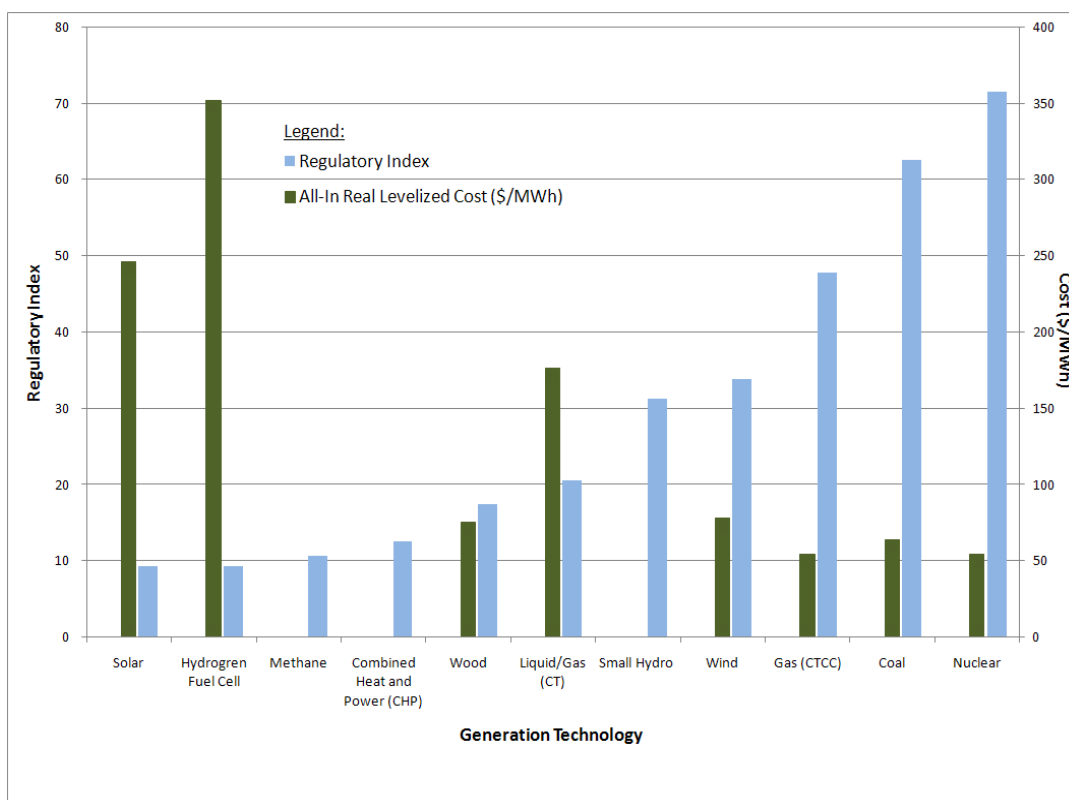
¹ The Vermont Utilities as a group is composed of Central Vermont Public Service Corporation; Green Mountain Power Corporation; Washington Electric Cooperative; Vermont Electric Cooperative, and; the Vermont Public Power Supply Authority.

² The Vermont Public Power Supply Authority did not participate in Phase 2 of the study.

Economic Cost and Regulatory Risk

Results from the study indicate an inverse relationship between the construction, operation and maintenance cost of new generation alternatives and their associated environmental and social risk. This finding is shown graphically in the figure below where the green bars reflect cost on a \$/MWh basis and the light blue bars reflect an index of relative regulatory risk where higher scores reflect greater environmental issues and public concerns.

- Generation sources identified as having the lowest expected economic costs on a \$/MWh basis (i.e. Pulverized Coal, Gas Combustion Turbine Combined Cycle, and Nuclear) present difficult scale and financing issues and may present equally challenging public acceptance and environmental issues (see figure below). Infrastructure requirements also severely limit the siting of such technologies.
- Methane, Combined Heat and Power (CHP) and wood technologies represent relatively low to moderate economic costs and regulatory risks. These technologies all have the potential to contribute to the state’s renewable energy goals and are reflective of general public interest in development of smaller-scale generation that utilizes indigenous resources



Comparison of Construction, Operation and Maintenance Cost³ and Relative Regulatory Risk⁴

³ Costs estimates are taken from *Vermont Utilities Technical and Cost Issues of Generation Alternatives – Phase One Report* and reflect the “All-in Realized Cost” defined as the annual payment that would have to be made over the life of a given plant, after adjusting for inflation, in order to pay for all of the plant’s capital and operating costs, including emissions costs. Value is expressed as \$/MWh in \$2008. This value does not include pre-construction, permitting or design costs. Levelized costs for combined heat and power, methane, and small hydro are not shown, because these technologies were not evaluated in the Phase 1 Report.

⁴ Regulatory risk is reflected using an index where higher scores indicate greater environmental issues.

Renewable Technologies

- Development of renewable technologies such as solar, wind, and wood could contribute to the state's energy goals with fewer environmental costs, but would be more expensive to develop on a \$/MWh basis. These technologies also tend to produce fewer MWs per development and thus would require more individual facilities to meet Vermont's electricity needs.
- Renewable resources could play an important role in addressing Vermont's potential supply gap, but a larger baseload plant, or several medium-sized baseload plants, may warrant consideration given costs, transmission constraints and energy needs.
- Wind and small hydro technologies face potentially difficult siting challenges that increase permitting time and risk. Both technologies have very specific siting requirements (i.e. must be located on ridgelines and in rivers) that typically involve sensitive resources with increased potential for opposition. Favorable wind sites are also typically not associated with existing transmission infrastructure.

Fossil and Nuclear Based Technologies

- Larger capacity combined cycle combustion turbine technology represents a relatively low cost option for meeting intermediate and baseload needs, but would involve relatively large regulatory costs and risks, due in part to the likely need for new electrical transmission and natural gas transmission. Smaller capacity combustion turbines that could be sited at existing facilities and could burn liquid, gas, and/or bio fuels to meet peak loads would involve moderate costs and moderate regulatory risks.
- Nuclear and coal technologies represent least cost options from the perspective of projected direct costs per MWh, but have the highest risk in terms of environmental impacts, likely public opposition and regulatory timeframes. Obtaining approvals for these technologies could increase the ultimate cost per/MWh and could involve expenditures for a project that may never be approved, or may not be economical once the permit conditions are factored in.
- The development of new nuclear and coal-based generation in Vermont would be extremely difficult due to a combination of the relatively large footprints required; fuel transport and storage, the potential for numerous adverse environmental and social impacts; the likely need for new transmission facilities; existing public policies that specifically discourage fossil fuel technologies; and public opinion that generally opposes such technologies. Given these factors, it is unlikely that a new nuclear or coal plant would actually be proposed in Vermont.

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1.0 INTRODUCTION

Nearly two-thirds of Vermont's electricity requirements, amounting to approximately 600 MW of generation are currently met through power contracts with Hydro-Quebec and the Vermont Yankee Nuclear Power Station. The bulk of these contracts are set to expire between 2012 and 2016, creating the potential for a large gap in generation supply for the State.

In an effort to explore options for addressing the state's long-term electricity needs, a consortium of Vermont utilities initiated a two-phased study of the costs, infrastructure, and permitting requirements for siting and constructing new generation facilities in Vermont. Phase 1 of the study, completed in January 2008, examines potential generation technologies, their costs, and possible financing structures (<http://www.cvps.com/AboutUs/news/CEAVermontGeneration%20Report11808final.pdf>). Phase 2 examines electric transmission, other infrastructure, and regulatory issues related to siting new generation.

1.1 Purpose and Scope

The purpose of this report is to provide a summary of the infrastructure and permitting issues, costs and challenges related to siting and constructing new grid connected generation facilities in Vermont.

Specific objectives include:

1. Identify existing infrastructure capabilities, constraints and needs, including those related to the State's electric transmission and distribution system;
2. Identify and explain the specific permits that would be required for construction of different types of grid connected generation technologies;
3. Assess issues and challenges that Vermont Utilities can expect to encounter in Vermont's permitting processes, including timeframes and costs, and;
4. Identify which permitting challenges create risks that can not be predictably overcome and thus threaten basic resource feasibility, engender uncertain project cost variances or challenge implementation timelines.

The report provides general information that applies broadly to the siting of new generation designed to be interconnected⁵ to and operate in parallel with the electric network. It outlines standard regulatory processes that different generation technologies would be subject to, the general characteristics and considerations that would influence regulatory approvals, and the difficulties associated with those approvals.

⁵ Note that this report does not address the permitting issues associated with non-grid connected generation such as net-metered projects or self-generation projects that are interconnected for parallel operation with the electric system of the host electric utility.

For consistency, this report examines the same range of generation technologies outlined in the Phase 1 report and incorporates the same assumptions regarding their size and potential location. The report also examines several generation technologies not included in the Phase 1 report including, methane, Combined Heat and Power (CHP, including co-generation), and small hydro.

Specific generation facilities considered in this report, and their assumed installed capacity are listed below. Listed installed capacities are representative. Actual capacities could be higher or lower depending on the site constraints, including transmission considerations and local/regional needs.

1. Solar – up to 5 MW
2. Hydrogen Fuel Cell – up to 10 MW
3. Methane – up to 5 MW
4. Combined Heat and Power (CHP) – up to 10 MW
5. Small Hydro – up to 5 MW
6. Wood: Stoker and Circulating Fluidized Bed - 50 MW
7. Wind – 50 MW
8. Combustion Turbine (Liquid and/or Gas Fueled) – 50 MW
9. Combustion Turbine Combined Cycle (CTCC) – 560 MW
10. Coal: Integrated Gasification Combined Cycle; Pulverized; Circulating Fluidized Bed – (640 – 750 MW)
11. Nuclear⁶ – 1,350 MW

1.2 Report Organization

Following this introduction, Section 2 of the report provides a brief overview of infrastructure capabilities, constraints and needs. Section 3 outlines the approach used to assess regulatory challenges and provides a summary of the key regulatory processes that would be involved in developing new generation in the state. Section 4 outlines the study methods, key assumptions, and data sources applied to the regulatory analysis. Section 5 provides a summary of findings, including findings relative to each of the generation options examined.

⁶ This category refers to construction of new nuclear facilities, not re-licensing of the existing Vermont Yankee station.

2.0 INFRASTRUCTURE CONSTRAINTS AND NEEDS

The following sections describe issues related to existing infrastructure, including electrical and gas transmission facilities and fuel delivery.

2.1 Electrical Transmission

Local Transmission/ Interconnection

The Vermont transmission system was originally designed to import power from New York and Southern New England and deliver the power to the Vermont distribution utilities. Vermont loads are much lower than Southern New England loads and therefore the transmission system has comparably lower voltage facilities and smaller conductors. The bulk system substations feed sub-transmission and distribution systems, often radials. Load carrying capabilities of lines need to be considered in context with local loads and through flows. If local loads are low the limiting factor is not voltage level alone since the flow will be the reverse direction for which the system was designed. Voltage level, conductor size, local load levels and through transfers should be considered to determine the feasibility of siting a power plant. Line capacity can be increased by entire replacement or expansion, by a voltage upgrade or by replacing conductors and additional transformation capacity. Costs could range from \$1-3 million per mile depending on the specific requirements.

Independent System Operators – New England (ISO-NE) and the member transmission utilities have a process to accept requests for new interconnections and to analyze the impacts on the system to determine if the system can accommodate the request or needs upgrades. That process is defined on the ISO-NE web site at http://www.iso-ne.com/trans/services/types_apps/index.html.

Relationship to Vermont Transmission Plan

The Vermont Electric Power Company (VELCO) ten year plan (twenty year plan after 2009) identifies future upgrades necessary to meet reliability standards. Inspection of the plan may reveal areas where generation could defer an upgrade. Similarly individual transmission suppliers (CVPS, GMP and VEC) publish integrated resource plans with information about sub-transmission and distribution upgrade needs. The generation planner needs to work with the appropriate wires company(ies) to determine the size, location and operating characteristics of generation that could have wires deferral value or interim reliability value in the time period before a wire can be upgraded. Figure 2.1 shows the location and voltage level of transmission lines in Vermont as of 2005 with rough indications of the plant size constraints and areas where generation is needed more than others to enhance system performance.

VELCO conducts long-range planning studies under state guidelines and coordinates planning with ISO-NE. Transmission planning generally is concerned with local and regional reliability concerns although there may also be a need to accommodate through flows for economics, e.g., there may be a need to provide a path for power from an

adjacent control area to reach New England markets. A new process is evolving from the settlement in Vermont Public Service Board Docket 7081. VELCO will produce a 20 year planning study and the investment decisions considering transmission and non-transmission alternatives (so-called NTAs such as demand-side management and generation) will be considered by the Vermont System Planning Committee with purposeful public involvement.

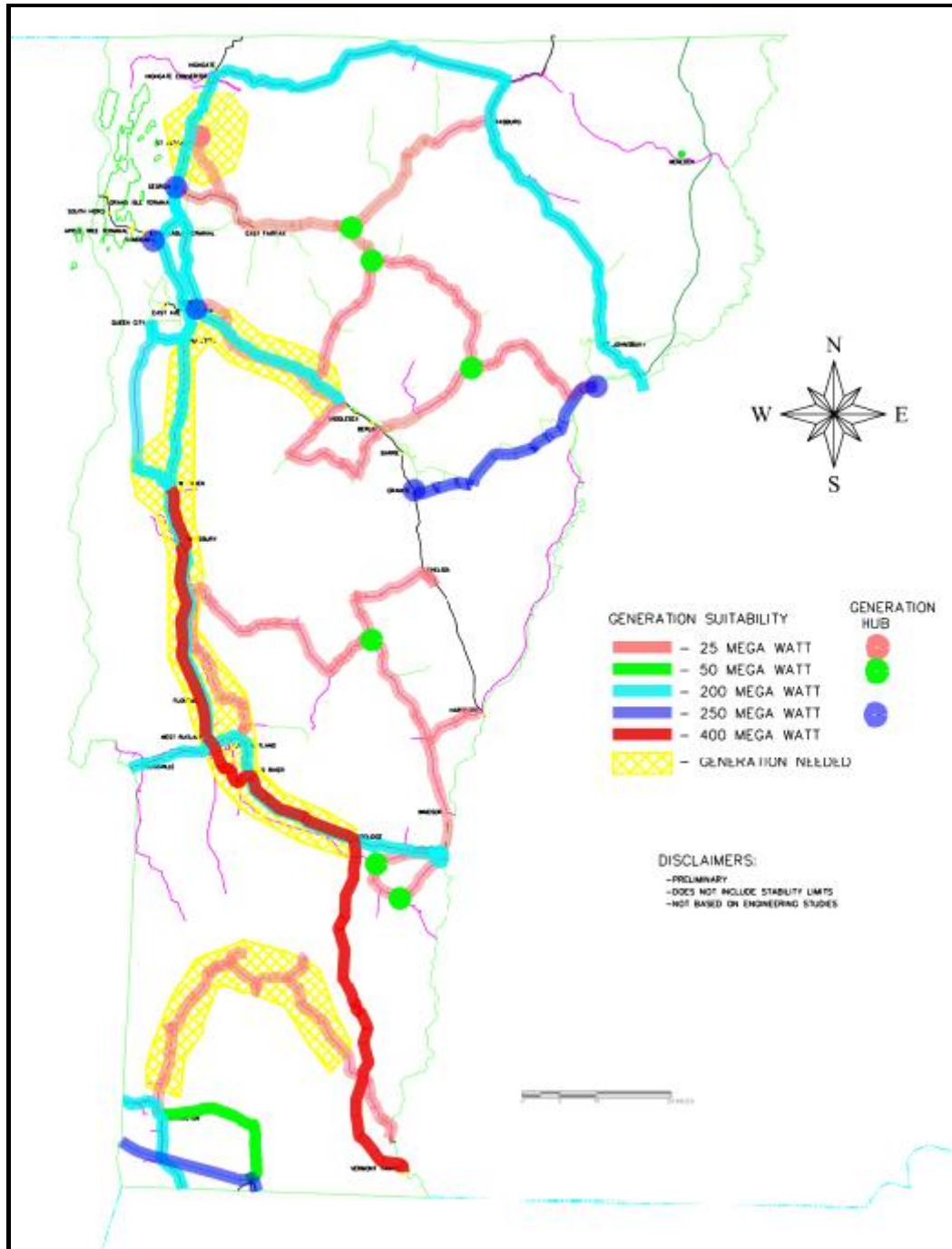


Figure 2.1 – Existing Transmission Line Constraints and Projected Areas of Generation Needs.

2.2 Fuel Facilities and Delivery

Fuel handling infrastructure, facility, and delivery requirements are driven primarily by generation technology and plant operations. Renewable generation technologies which rely on natural ambient resources such as solar and wind do not require fuel storage or transportation facilities. When fuel is imported to the facility consumption characteristics further define the fuel related infrastructure requirements (i.e., peaking plants operate less frequently and generally require less fuel than baseload plants).

Issues associated with the transportation of fuels such as natural gas, oil, propane, coal or wood depend on the volume and frequency of fuel deliveries and the existing infrastructure. Some fuels such as wood and coal require significant transportation and storage logistics. Because wood has a higher moisture content than other fuels, larger volumes of fuel need to be transported and stored for a given sized generating facility. This can have adverse impacts on traffic and roads if trucks are used for transport.

Vermont Gas Systems (“VGS”) provides pipeline and retail service for natural gas in Vermont. The VGS retail distribution system serves over 40,000 customers in northwest Vermont in Chittenden and Franklin Counties. The VGS system is shown in Figure 2.2. Additional information on the VGS system is provided in Section 2.2.1 below.

Vermont’s existing rail system is shown in Figure 2.3. The ability for this system to haul large quantities of coal is unlikely, but the infrastructure capability and upgrade costs would need to be evaluated as a constraint to potential coal-fired plant site options along with transmission constraints.

There is a possibility that fuel could be barged to the eastern shore of Lake Champlain via the St. Lawrence Seaway or the Hudson River. Capabilities of such barge traffic and the ability to off load shipments in Vermont are not apparent and would need to be explored to determine the potential of sites along Lake Champlain or inland based on rail or truck shipment to a site. While the Connecticut River on the eastern side of Vermont is navigable by small craft the existing hydroelectric dams are an impediment to barge traffic.

2.2.1 Vermont Gas Systems

Supply and Demand

Natural gas demand in Vermont is driven by winter heating needs, with about 80 percent of residential customers’ gas consumption occurring during the winter months of December through March. As a result, total throughput on the VGS system is heavily weighted toward winter months, and there is much more capacity to deliver additional gas during the summer. Most VGS customers are presently served on a firm (year-round) basis, although a portion of VGS load is non-firm and can be interrupted if needed during periods of high winter gas demand. Currently one electric generating facility, the

McNeil plant, is served by VGS. The McNeil plant is tri-fuel capable (i.e., capable of burning wood, fuel oil and natural gas), with wood being the primary fuel consumed.

The VGS system could accommodate (or be upgraded to accommodate) substantial gas-fired generating capacity. The required costs (and, therefore, the economic viability of new gas-fired capacity) would depend on the extent of system upgrades, if any, required within Vermont, and on the TransCanada Pipeline (“TCPL”) gas transmission system which supplies Vermont. The required upgrades would depend greatly on the size of the power plant, its location on the VGS system, and whether the plant required firm year-round gas supply or (alternatively) could use oil as a backup fuel during times of high gas demand.

TransCanada Pipeline (TCPL) System Capacity

The VGS system is fed in a radial fashion from the transmission system of the TCPL from Phillipsburg, Quebec. While physically interconnected with the U.S. natural gas pipeline network at numerous points on its system, the primary supply basin for the TCPL system is Alberta, Canada. Vermont’s present natural gas consumption is small relative to the total throughput of the TCPL transmission system, and relative to the level of natural gas consumed in southern Quebec, including Montreal.

Almost all of the TCPL system is looped, (i.e., two or more pipes operating in parallel). Approximately 19 kilometers of the TCPL system serving Vermont consist of a single 8-inch pipe terminating in Phillipsburg, Quebec. TCPL is planning on looping 6.5 kilometers of this section in 2008. VGS indicates that in order to serve a significant new firm natural gas load (such as a power plant requiring firm gas supply) in Vermont, additional expansion of the TCPL system would likely be needed. How the additional expansion is addressed, either through compression or additional pipeline, would be decided by TCPL. Based on their dealings with TCPL, VGS believes such expansion would not be problematic for TCPL and estimates the lead time for such a project, including permitting, to be approximately 3 years.

Increasing TCPL’s delivery capacity to accommodate additional firm Vermont load would, however, likely require a significant financial commitment. TCPL’s current practice is to require a 10-year firm transportation contract. The actual system requirements and associated costs would be determined by a system upgrade study.

Generation Requirements Relative to VGS System Capacity

In total, the VGS transmission system includes about 70 miles of high-pressure pipeline and about 603 miles of local distribution mains. VGS presently distributes over 8 Bcf per year, with a pipeline peak day delivery capacity of roughly 60,000 million cubic feet per day (mcf/d). Figure 2.2 shows the VGS delivery system. VGS expands its system, both distribution and transmission, in response to planned load growth.

A utility scale power plant would represent a very significant load in the context of the current VGS system. For example, a 25 MW simple cycle combustion turbine (a generating unit typically used for peaking duty) operating for 8 hours would consume

approximately 2,100 Mcf in a day. This would represent roughly 6 percent of the VGS system's current average sales during peak winter months, and about roughly 18 percent of average sales in summer. A 50 MW combustion turbine (or two 25 MW ones) would consume about twice as much. As is discussed further below, the VGS system could potentially accommodate electric generating capacity in this size range on a non-firm basis without significant system upgrades.

In contrast, a 200 MW combined cycle plant (better suited for round-the-clock operation) operating 24 hours per day would consume roughly 22,400 MMcfd. This additional gas supply would represent roughly 60 percent of VGS' current average gas sales in winter, and almost twice VGS' average sales in summer months. The VGS system would need substantial capacity upgrades in order to serve a plant of this size on a firm basis, or on an interruptible basis with limited interruptions.

Location Considerations

The northern end of the VGS system (i.e., from St. Albans north, where there are parallel 16-inch and 10-inch supplies) could likely transport sufficient gas to fuel a substantial (i.e., several hundred MW) natural gas-fired plant on a firm basis, without major system upgrades.

In order to provide firm service to a power plant in a more southerly location on the existing VGS system (e.g., in Chittenden County, a more ideal location from the perspective of the electric transmission system), VGS would need to significantly expand the southern throughput of its current transmission system – presumably through additional looping and/or increased compression. Based on past experience, Vermont Gas indicates that the lead time for such expansion, including permitting through construction, is approximately 2 years.

Generator Cost-Effectiveness

The capital costs required to enhance the VGS and TCPL transmission systems to supply a new power plant would depend significantly on the size of the plant and its location. While site-specific estimates are beyond the scope of this study, a generic “rule of thumb” cost of \$1.5 million per mile for construction of transmission pipeline can be used to obtain a rough sense of the magnitude. Based on this indicative cost level, VGS indicates that to provide firm service to a new 25 MW generator located on its existing gas transmission system, it could likely expand the looped portion of that system southward at a capital cost of a few million dollars (i.e., \$100/kW to \$150/kW).

This same illustrative level of pipeline costs indicates that a generating plant seeking to locate a significant distance from the existing VGS transmission network would face significant incremental capital costs, relative to a comparable plant located near the existing system. For example, a generator seeking to locate 6.5 miles from the VGS system might (using the “rule of thumb” cost above) face an incremental capital cost on the order of \$10 million. Such capital costs could be collected as an up-front charge or, more likely, over time via non-bypassable gas transmission charge. For a 25 MW power plant, this incremental capital cost would represent about \$400 per kW – an amount that

would be very significant in the context of the total plant capital cost, and would likely make such a plant uncompetitive relative to New England electricity market alternatives. Incremental gas infrastructure costs would represent a much smaller fraction of the capital and operating costs for a larger combined cycle plant, but could still meaningfully reduce the cost-effectiveness of a Vermont plant relative to other gas-fired power plant options in the region – particularly if the plant were located farther from the existing VGS system.

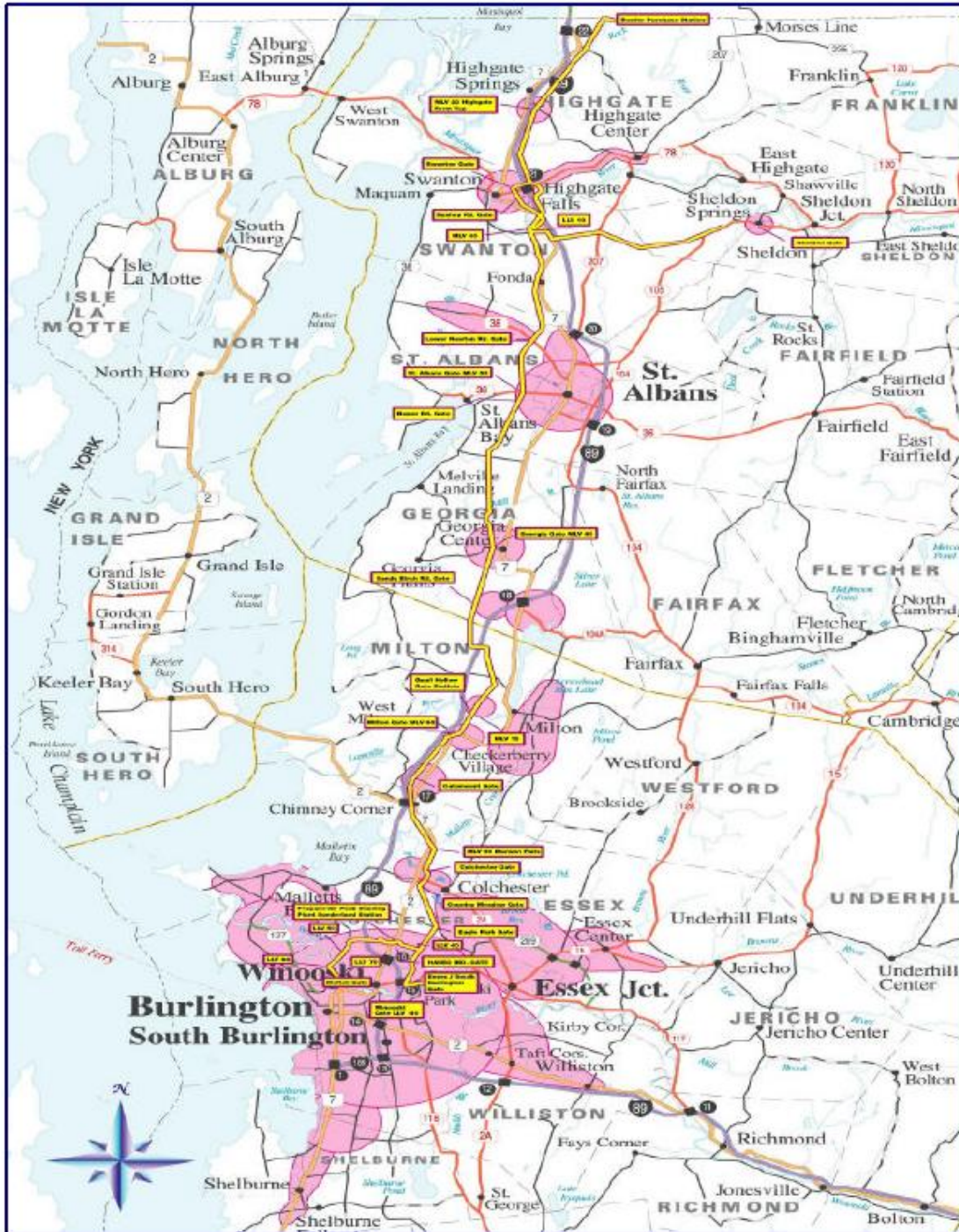
In summary, the gas infrastructure enhancements required to provide firm gas supply to a new power plant in Vermont would depend significantly on the plant's location, with locations at or north of St. Albans (and those not requiring significant spurs from the existing VGS transmission network) being the least costly. While a Chittenden County location would likely be more ideal from the perspective of the electric transmission system, the associated costs to enhance Vermont's gas transmission system would be higher. A new generating plant requiring significant extension of the VGS transmission system would face more substantial capital costs which could meaningfully reduce the plant's cost-competitiveness.

Non-Firm Gas Supply

As discussed above, some significant capital investment would likely be needed to support a firm supply of natural gas to a Vermont generating unit. In contrast, VGS indicates that significant gas transmission capacity is available on its existing system and on the TCPL system during most months of the year. As a result, non-firm service – that is, operation on gas when sufficient delivery capacity is available during non-winter months, and on an alternate fuel, most likely fuel oil, during the winter – could likely be provided for a generating plant along the existing VGS system without most of the gas transmission system expansion steps identified above. A plant taking non-firm gas service would only need to incur the gas interconnection costs identified above, and to have sufficient alternate fuel storage and transportation options to fuel the unit during winter periods when gas is not available.

VGS indicates that from the perspective of transmission capacity, preliminary analysis shows that its current system could accommodate an additional load of 25 MW to 50 MW of gas demand on all but the coldest winter days. It is therefore possible that for a peaking unit burning interruptible natural gas, the use of oil backup fuel would, in actual practice, be quite limited. We note that because a peaking generating unit would tend to be called upon to operate during the coldest days, it would be important to install a backup fuel supply (such as distillate oil or kerosene, which fuel much of Vermont's present peaking capacity).

In order to implement a non-firm gas supply, some commercial and operating considerations (e.g., in the case of a peaking unit, arrangement of wholesale gas supply, to be available to the VGS system on very short notice) would also need to be addressed. Initial discussions with VGS and industry consultants suggest that solutions to these issues could be developed, although the development of specific approaches is beyond the scope of this study.



Source: Vermont Gas

Figure 2.2 – Vermont Gas Distribution Line and Service Territory 2006

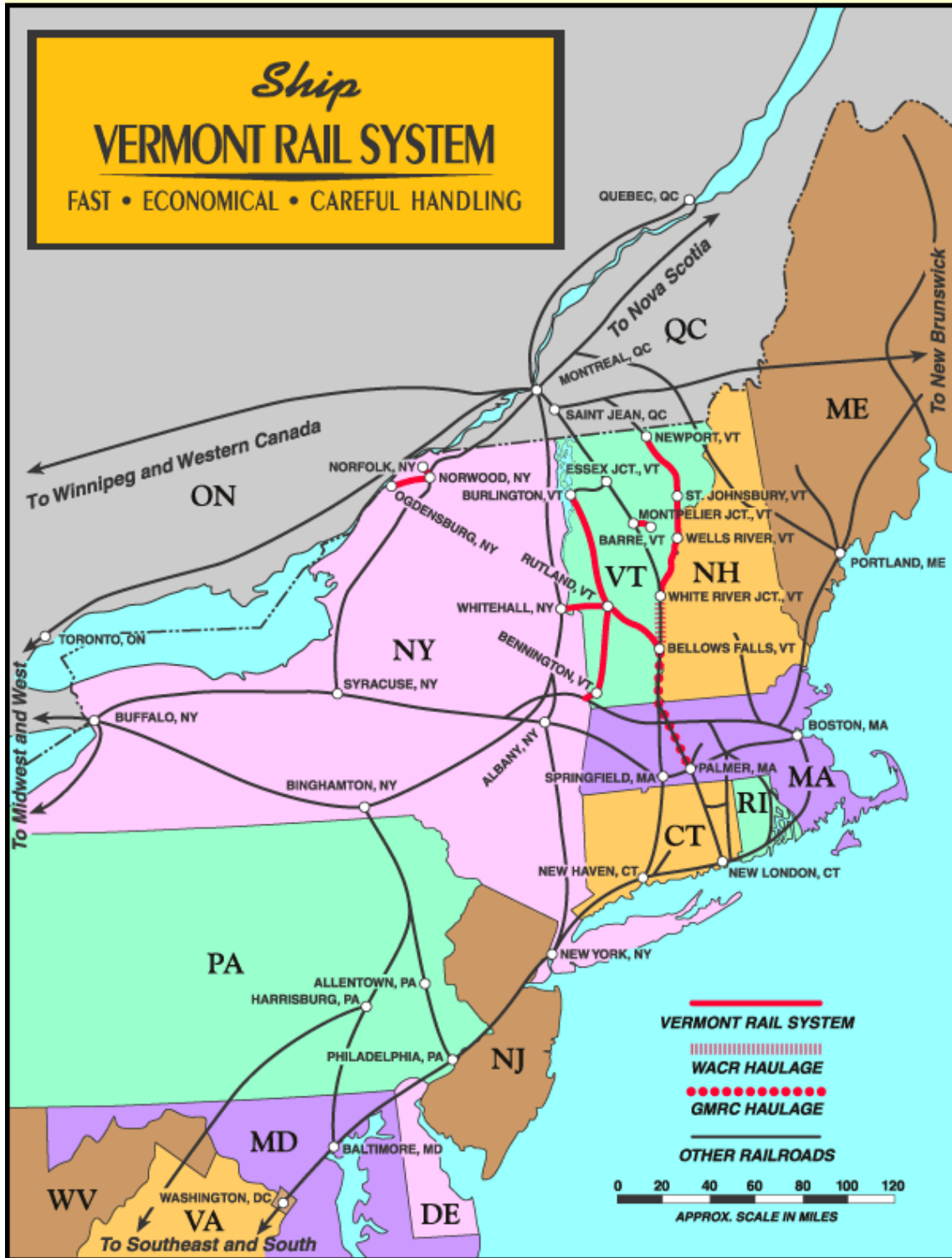


Figure 2.3 – Vermont Rail System Regional Map

3.0 POLICY AND REGULATORY OVERVIEW

The following sections briefly summarize state policies and programs and regulatory processes that could be involved in planning and siting new generation facilities. More detailed information regarding specific statutes and regulatory approvals, including regulatory standards and thresholds is provided in Appendix B.

3.1 State Policies and Programs

There are several policy and guidance documents and programs related to electrical generation in Vermont. Vermont does not have a prescriptive policy to build generation in Vermont. The Sustainably Priced Energy Enterprise Development (SPEED) Program and the State Electricity Plan both encourage the development of renewable resources.

State Electricity Plan

The 2005 State Electric Plan “serves to help guide utilities in their own planning activities by establishing a standard of planning and analysis for utilities. The Plan supports and guides Department actions in public advocacy before the State and federal regulators. Similar to prior plans prepared by the Department, this Plan is not a prescriptive resource plan. Several resource portfolios are, however, presented in the document for reference and discussion. The Electric Plan is designed to help guide utilities and the state to operate in a coordinated manner consistent with legislated goals and a supportive regulatory and policy environment. As with prior electric plans, this Plan provides broad guidance to utilities, regulators and policy makers to move the sector into the future.

Since the establishment of the Department’s last Electric Plan in 1994, the industry has been transformed. Ten years ago, wholesale energy was centrally dispatched based on costs. Today, there is a competitive wholesale market for electricity with dispatch determined by the bid-in prices. Area specific market-clearing prices rather than generator costs now form the basis of market settlements between buyers and sellers. At the retail level all of the neighboring states in the region have moved to retail choice. Vermont’s electric sector remains a vertically integrated monopoly environment.

Major challenges ahead include the replacement of major power source contracts representing roughly two-thirds of the Vermont energy mix in the period from 2012 and 2015. Many individual Vermont electric utilities face major resource decisions even sooner. Steps taken today by the State, Vermont Utilities, and other stakeholders today will create opportunities for addressing tomorrow’s challenges. Vermont is already confronting major decisions in relation to transmission and distribution constraints in the state. Ten areas of the State have been identified as constrained and are the subject of on-going investigation. Continued growth in the Northwest region of the State will likely continue to present fresh reliability challenges in the next decade. Addressing those challenges in a least-cost manner may require an early understanding of the potential

transmission solution so that both generation and efficiency services may provide a portion of the solution.”

Additional information on the State Electric Plan is available at <http://publicservice.vermont.gov/pub/state-plans/state-plan-electric2005.pdf>.

Comprehensive Energy Plan

Fueling Vermont's Future: Vermont Comprehensive Energy Plan and Vermont Greenhouse Gas Action Plan, outlines Vermont's present energy situation, projects future energy use and models and recommends energy policies for the next 20 years. The plan is mandated by Vermont law (30 V.S.A. § 202a and b) and seeks to outline an energy strategy that is safe, adequate, reliable, secure, sustainable, environmentally sound, efficient, and affordable, while maintaining economic vitality.

Additional information on Vermont's Comprehensive Energy Plan is available at <http://publicservice.vermont.gov/pub/state-plans/cepov.pdf>.

Sustainably Priced Energy Enterprise Development (SPEED) Program

The SPEED program requires the states distribution utilities to meet energy growth needs from January 2005 through 2012 with new renewable resources with a floor of 5% of the 2004 energy needs and a ceiling of 10%. If the goals are not met, then the Public Service Board may establish a Renewable Portfolio Standard (RPS).

Additional information on the SPEED program is available at <http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=089&Section=08005>.

Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is designed to cap CO₂ emissions from large electric generating units in a nine state region of the Northeast by requiring affected generators to purchase allowances sufficient to cover their actual emissions during each compliance period. Vermont was allocated an initial set of allowances and has decided to sell essentially all of those allowances with the proceeds to fund an energy efficiency program for fuels other than electricity.

Additional information on the RGGI program is provided at <http://www.rggi.org/>.

3.2 Title 30 Section 248

New and modified electrical generation and transmission facilities must receive a Certificate of Public Good (CPG) from the Vermont Public Service Board (PSB)⁷. See http://www.state.vt.us/psb/document/Citizens_Guide_to_248.pdf for a summary of the PSB 248 process.

In order to ensure that a proposed project is economically, environmentally, and socially beneficial to the State's rate payers the PSB evaluates the proposal based on ten criteria. The ten evaluation categories measure proposed projects against a range of performance criteria that evaluate the economic and environmental impacts of the project on the general good of the state, its ratepayers and communities, natural resources, historic properties and governmental services. Each category has impact thresholds which the PSB uses to gauge the relationship of the proposal to the applicable permitting criterion. The ten categories are listed below. Thresholds for each of these categories are summarized in Appendix B.

- 248(b)(1) Orderly Development of the Region
- 248(b)(2) Need for Present and Future Demand for Service
- 248(b)(3) System Stability and Reliability
- 248(b)(4) Economic Benefit to the State
- 248(b)(5) Aesthetics, Historic Sites, Air and Water Purity, the Natural Environment and Public Health and Safety
- 248(b)(6) Consistency with Approved Integrated Resource Plan (IRP)
- 248(b)(7) Consistency with Electrical Energy Plan
- 248(b)(8) Outstanding Resource Waters
- 248(b)(9) Solid Waste Management
- 248(b)(10) Existing Transmission Facilities

Securing a CPG can be a relatively lengthy and resource intensive undertaking. Because the process is quasi-judicial, exhibits must be prepared and submitted and testimony given subject to contested case schedules and procedures developed in accordance with the requirements of 3 V.S.A. § 809 which often requires resource experts. In addition to preparing for hearings, applicants must be prepared to respond to formal discovery and evidence submitted by interveners, state and local governmental agencies, the DPS, who serves as the public advocate, and other interested stakeholders. Technical hearings conducted by the PSB are governed by the Board's Rules of Practice which apply the Vermont Rules of Civil Procedure and Evidence; *see* PSB Rule 2.000. Public hearings conducted under the Section 248 process represent additional points of exposure and risk. Conditions attached to a CPG can add significant costs and time to a project, especially if post-CPG proceedings or compliance filings are required.

⁷ Replacement of existing facilities with equivalent facilities in the usual course of business, and electric generation facilities that are operated solely for on-site electricity consumption by the owner of those facilities do not require a CPG.

3.3 Federal Statutes and Regulatory Approvals

Clean Air Act

The Vermont Air Pollution Control Division (APCD) of the Department of Environmental Conservation (DEC) implements the state and federal Clean Air Acts. As part of this implementation, the APCD monitors air quality and air pollution sources, proposes regulations to improve existing air quality, ensures compliance with the regulations, and issues permits to control pollution from sources of air contaminants across the state. The APCD issues construction and operating permits:

- *Construction Permits* - A construction permit, or a determination by the APCD that a permit is not required, is necessary before a project can be installed, constructed or modified. Construction permits are valid for the life of the project and are only reissued if changes are planned for the permitted activity which require a permit review.
- *Operating Permits* – Operating permits incorporate all the air pollution control requirements a facility is subject to into one document. Operating permits must be renewed every five years to incorporate any new requirements that may have been adopted since the original operating permit was issued.

Construction and operating permits are further divided into four categories based primarily on emission criteria, including:

- New major source (≥ 50 tons/year of any contaminant or ≥ 5 tons/year of lead)
- New minor source
- Major modification (\geq significant increase or ≥ 50 and ≥ 5 tons/year as above)
- Minor modification

An acid rain permit may also be required for affected utility generators if:

- The generator nameplate capacity is >25 MWe, and;
- Fuel has an average sulfur content of $>0.05\%$.

Requirements to obtain an Acid Rain permit include, monitoring emissions, holding allowances, compliance with emission limitations, and fulfilling recordkeeping and reporting requirements. Units that require an Acid Rain permit are also required to obtain or be included in a Title V operating permit.

Thresholds for each of these categories are provided in Appendix B. Additional information on Vermont's air pollution control policies and associated regulatory processes is available at <http://www.anr.state.vt.us/air/index.htm>.

Rivers and Harbors Act

Section 10 Rivers and Harbors Act of 1899 covers construction, excavation, or deposition of materials in, over, or under such waters, or any work which would affect the course, location, condition, or capacity of those waters. The authority is granted to the Secretary

of the Army and is implemented by the Army Corps of Engineers. The geographic jurisdiction of the Rivers and Harbors Act of 1899 includes all navigable waters of the United States. Activities requiring Section 10 permits include structures and work such as dredging or disposal of dredged material, or excavation, filling, or other modifications to the navigable waters of the United States.

The Clean Water Act also uses the term "navigable waters" to define jurisdictional limits. By definition jurisdiction under Section 404 of the Clean Water Act encompasses Section 10 waters plus their tributaries and adjacent wetlands and isolated waters where the use, degradation or destruction of such waters could affect interstate or foreign commerce. Regulatory authority over activities within jurisdictional areas is provided in Section 10 of the Rivers and Harbors Act and is commonly implemented through the permitting programs established under Section 404 of the Clean Water Act.

Clean Water Act

The Clean Water Act (CWA) employs a variety of regulatory tools to reduce direct pollutant discharges into waterways, and manage polluted runoff. The CWA is implemented by the DEC or the US Army Corps of Engineers (Corps) depending on the applicable section of the CWA. Additional information on the CWA and its implementation in the New England region is available at <http://www.epa.gov/region01/topics/water/cwa.html>. Sections of the CWA that may be applicable to new generation projects include:

- *Section 402 – National Pollution Discharge Elimination Systems (NPDES)*
Covers point and non-point sources of pollution discharging into a surface waterbody. Potentially applicable sub-sections include:
 - 316(a) – thermal discharge from cooling water systems
 - 316(b) – impingement and entrainment of aquatic organisms associated with cooling water systems.
- *Section 404 – Wetlands and Waterways Dredge and Fill Permits*
Regulates the placement of dredged or fill materials into wetlands and other Waters of the United States.
- *Section 401 - Water Quality Certification*
Requires federal agencies to obtain certification from the state, territory, or Indian tribes before issuing permits that would result in increased pollutant loads to a waterbody. The certification is issued only if such increased loads would not cause or contribute to exceedances of water quality standards.

Additional information on the CWA and potential applicability is provided in Appendix B.

Vermont Wetland Rules

The Vermont Wetland Rules identify and protect 10 functions and values of "significant" wetlands and establish a 3-tier wetland classification system to identify such wetlands. Class one and two wetlands and their associated buffer zones are protected under the wetland rules. Class three wetlands are not addressed by the state wetland rules but may be subject to federal regulations.

Any activity within the wetland review area that is not identified or determined to be an “allowed” use are considered “conditional” uses. Conditional uses are only allowed in significant wetlands or in adjacent buffer zones upon receiving a Conditional Use Determination (CUD).

Additional information on the Vermont Wetland Rules and potential applicability is provided in Appendix B.

Vermont Stormwater Rules

The Vermont Agency of Natural Resources (ANR) regulates stormwater discharges to surface waters that are not identified as impaired by stormwater runoff. ANR issues general permits to a category of projects, rather than on an individual project basis with certifications of compliance from stormwater consultants. State-issued general permits include coverage for:

- Stormwater discharges from new development and redevelopment, and;
- Previously permitted stormwater discharges.

In addition the DEC administers federal NPDES permits for stormwater discharges associated with construction sites and the multi-sector general permit.

Additional information on the Vermont Stormwater Rules, critical thresholds and potential applicability is provided in Appendix B.

Endangered Species Act and Vermont Non-game and Natural Heritage Program

Congress passed the Endangered Species Preservation Act (ESA) to allow the listing of native animal species as endangered and provided limited means for the protection of species. Section 7 of the Endangered Species Act directs all Federal agencies to use their existing authorities to conserve threatened and endangered species and to ensure that their actions do not jeopardize listed species or destroy or adversely modify critical habitat. Section 7 applies to management of Federal lands as well as other Federal actions that may affect listed species, such as Federal approval of private activities through the issuance of Federal permits, licenses, or other actions. Additional information on the ESA is available at <http://www.fws.gov/endangered/>.

ESA consultation is required if a federal permit is sought for a project. Consultations include review by the regional U.S. Fish and Wildlife Service (FWS) office to determine if there are any potential conflicts between known occurrences of listed species and the proposed project.

In addition to the ESA, the Vermont Nongame and Natural Heritage Program (NNHP) implement the Vermont Endangered Species Law. The program provides protection for State listed species and significant natural communities. The NNHP is similar to the federal ESA in the review and consultation process however the species that are legally protected on the state level reflect the status of populations within Vermont and are therefore different from the federal listings either in status (endangered or threatened) or

overall listing. Additional information on the VT NNHP is available at http://www.vtfishandwildlife.com/wildlife_nongame.cfm.

Additional information related to the federal ESA and Vermont's NNHP is provided in Appendix B.

Federal Power Act

The Federal Power Act (FPA) and its amendments authorized the creation of several agencies tasked with the regulation and management of energy resources. Agencies pertinent to this study include:

- *Federal Energy Regulatory Commission (FERC)*- FERC is an independent regulatory agency that oversees the natural gas, oil, and electricity markets in the U.S. FERC regulates the transmission and sale of these energies (except the sale of oil), provides licenses for hydroelectric plants, and reacts to environmental matters that arise. Additional information on FERC is available at <http://www.ferc.gov/>.
 - *Independent System Operator of New England (ISO-NE)* – ISO-NE was created by FERC to implement regulations related to electrical transmission. Additional information on ISO-NE is available at <http://www.iso-ne.com/>.
- *Nuclear Regulatory Commission (NRC)* – The NRC regulates the nuclear power industry to protect the public health and safety from nuclear radiation and waste. Additional information on the NRC is available at <http://www.nrc.gov/>.

Additional information on the FPA and its implementing agencies is provided in Appendix B.

Federal Land Use Policy Act

The Federal Land Use Policy and Management Act (FLPMA) governs all commercial uses or removal of products on public lands. Such uses require a special use permit which grants rights or privileges of occupancy and use to the holder. In Vermont the U.S. Forest Service (Service) implements the FLPMA and reviews special use permit applications.

The proposed use must:

- Comply with all management plans and laws,
- Demonstrate the need for the activity, and;
- Demonstrate that the use is appropriate on national forest system lands.

Special Use Permits are a temporary authority. Additional information on FLPMA is available at <http://www.blm.gov/flpma/>, information relating to special use permits administered by the Service is available at <http://www.fs.fed.us/recreation/permits/>.

Appendix B provides additional information regarding FLPMA and generation projects.

4.0 REGULATORY ANALYSIS

The following outlines methods, assumptions, and data sources used in evaluating the regulatory issues and challenges associated with permitting new generation in Vermont. For each of the selected generation facilities we examine the basic regulatory framework that would be applied, including the specific permit processes and tests that would be involved. We also identify the general challenges and estimate the degree of difficulty associated with the permitting process as described below.

4.1 Methods and Assumptions

Index of Regulatory Costs and Risk

To aid in comparing and contrasting amongst various options, we develop a simplified ranking, or index of regulatory cost (including time) and risk, which can be displayed in a summary matrix and graphically. The index utilizes a qualitative, non-linear scoring system based on the applicability of particular regulatory processes to the technology, the level of complexity and potential opposition that might be expected which affect timeframes and costs, and the overall risk profile. The index considers specific criteria used by the state's Public Service Board (PSB) in issuing a Certificate of Public Good (CPG) through the Section 248 process as well State and Federal regulatory processes designed to protect environmental resources. The specific regulatory processes considered and the criterion used to score each of the generation technologies are described in Attachment A.

Key Assumptions

Several simplifying assumptions were made for the purpose of evaluating regulatory costs and risks using the approach outlined above. These assumptions were:

- New gas generation would be sited near existing pipelines in the northwestern part of the state to avoid the costs, time and environmental impacts associated with construction of major new gas pipelines (see Section 2.2).
- Facilities with an installed capacity greater than 400 MW would require significant transmission system upgrades or new transmission lines subject to regulation independent of the associated generation proposal.
- Facilities with installed capacities less than 400 MW would be placed where there is suitable transmission.
- Wind generation would require new transmission facilities because options to site near existing transmission are generally not available where utility scale wind farms would be feasible.
- Small hydro would be installed where there is existing impoundment or diversion structure, but currently no power capacity.
- Combustion turbines using liquid or gas fuels would be sited at existing developed sites and would be operated as peaking plants. Plants would operate on liquid fuel during the winter months as a function of seasonal fuel price variability.

- Nuclear, coal, and wind would require use of undeveloped lands due to size and site suitability considerations. All other technologies could be constructed at existing developed sites.
- Larger MW facilities (>50 MW) would be less reliable than equivalent amounts of capacity from multiple, smaller distributed facilities.
- Wood, methane, and CHPs using renewable fuels would provide secondary economic benefits to the state due to the use of local fuel sources.
- All else being equal, technologies that qualify under the state SPEED program would entail less regulatory risk. Regulatory timeframes and costs would not be affected.

4.2 Data Sources

The analyses and findings presented in this report are based on information provided in a variety of existing public documents. These include documents prepared by the State as well as several documents generated by private institutions and academic institutes. The study also relies on material available in public dockets on specific proposals for new generation previously brought before the Public Service Board and the Agency of Natural Resources. The primary sources used are briefly described and listed below.

- *State Guidelines and Handbooks* - The state has published several reference documents such as the *Citizens' Guide to the Vermont Public Service Board's Section 248 Process* (http://www.state.vt.us/psb/document/Citizens_Guide_to_248.pdf) and the *Permitting Handbook* (http://www.anr.state.vt.us/dec/permit_hb/tableofcontents.htm) which provide basic information regarding various permitting processes. These and other similar documents as noted below, provide much of the factual basis for the analyses presented herein.
- *Statutes and Policy Documents* - There have been a number of state statutes enacted and public policy documents prepared over the past several years which are intended to influence energy development and/or provide information for evaluating the realities of permitting new generation in the state from a public policy perspective. These existing analyses include, but are not limited to: passage for Act 61 and the development of 30 V.S.A. sec 8005 which establishes incentives for renewable energy projects through the Sustainably Priced Energy Enterprise Development (SPEED) program; Executive Order 04-04 establishing the Vermont Commission on Wind Energy Regulatory Policy, and associated findings of the Commission; work conducted by the State Department of Public Service (DPS) on the State Electric Plan and its 2006 update; studies conducted by institutions such as the Vermont Public Interest Research and Education Fund (VPIREF) and the Windham Foundation on Vermont's electric energy future (<http://www.vpirg.org/globalwarming/decadeofchange.php>); and recent workshops conducted by the Vermont Law School Land Use Institute & Institute

for Energy and the Environment on regulatory issues related to the siting of new generation.

- *Public Engagement* - The DPS recently completed a comprehensive, statewide public engagement process on energy planning focused on energy supply choices facing the state as required by Act 208. Results from this public engagement process provide a very recent account of public opinion which is reflected herein as it pertains to specific power resource options. The report and findings of the DPS Vermont's Energy Future public engagement initiative are available at:<http://www.vermontenergyfuture.info/Results%20and%20reports.html>.
- *Case Studies* - In addition to the existing policy and regulatory documents, there has been a growing interest in building new power resources in the state, particularly wind power projects and small distributed generation which is reflected in recent permit applications. Environmental issues associated with these applications are reflected in the hearing notices and orders issued by the Public Service Board and other regulatory agencies. A review of these applications also provides a window into the typical timeframes that can be expected as well as the general level of effort in terms of required environmental studies and other analyses. There has also been a fair amount of activity in the region driven by increased energy prices and a growing gap between the supply of and demand for electricity. This activity provides insights on typical regulatory issues, particularly those related to compliance with federal statutes such as the Clean Air Act. Where applicable, observations regarding this activity are presented herein as they pertain to issues related to siting and construction of new generation facilities in Vermont.

Key documents reviewed for this study include the following:

- A Decade of Change, A Vision for Vermont's Renewable Energy Future (Summer 2006)
- Citizen's Guide to the Vermont Public Service Board's Section 248 Process
- Energy and Land Use: Merging the Regulatory Streams (February 2008)
- Fueling Vermont's Future, Comprehensive Energy Plan and Greenhouse Gas Action Plan (July 1998)
- Mediated Modeling for Participatory Energy Planning in Vermont (January 2007)
- Update to the 2005 Vermont Electric Plan (October 20, 2006)
- Vermont Commission on Wind Energy Regulatory Policy, Findings and Recommendations (December 15, 2004).
- Vermont's Electric Energy Future, Report of the Thirtieth Grafton Conference (July 2005)
- Vermont Electric Plan 2005 (January 19, 2005)
- Vermont's Energy Future, Public Engagement Process (January 2008)
- Vermont Public Service Board dockets.
- Vermont Utilities Technical and Cost Issues for Generation Alternatives, Phase One of a Two-Phase Report (January 18, 2008)
- Wind Energy Planning Resources for Utility-Scale Systems in Vermont (October, 2002)

5.0 STUDY FINDINGS

The following presents study findings, including an overall comparison of regulatory issues and challenges across different generation facilities. Potential issues associated with each generation technology are also discussed.

5.1 Relative Regulatory Risk

Figure 5.1 below presents an overall comparison of the relative regulatory costs and risk associated with each of the different types of generation considered. The index scores shown in Figure 5.1 are derived from an assessment of specific regulatory issues and permitting processes (see Appendix A). Representative installed capacities are depicted above the graph bars.

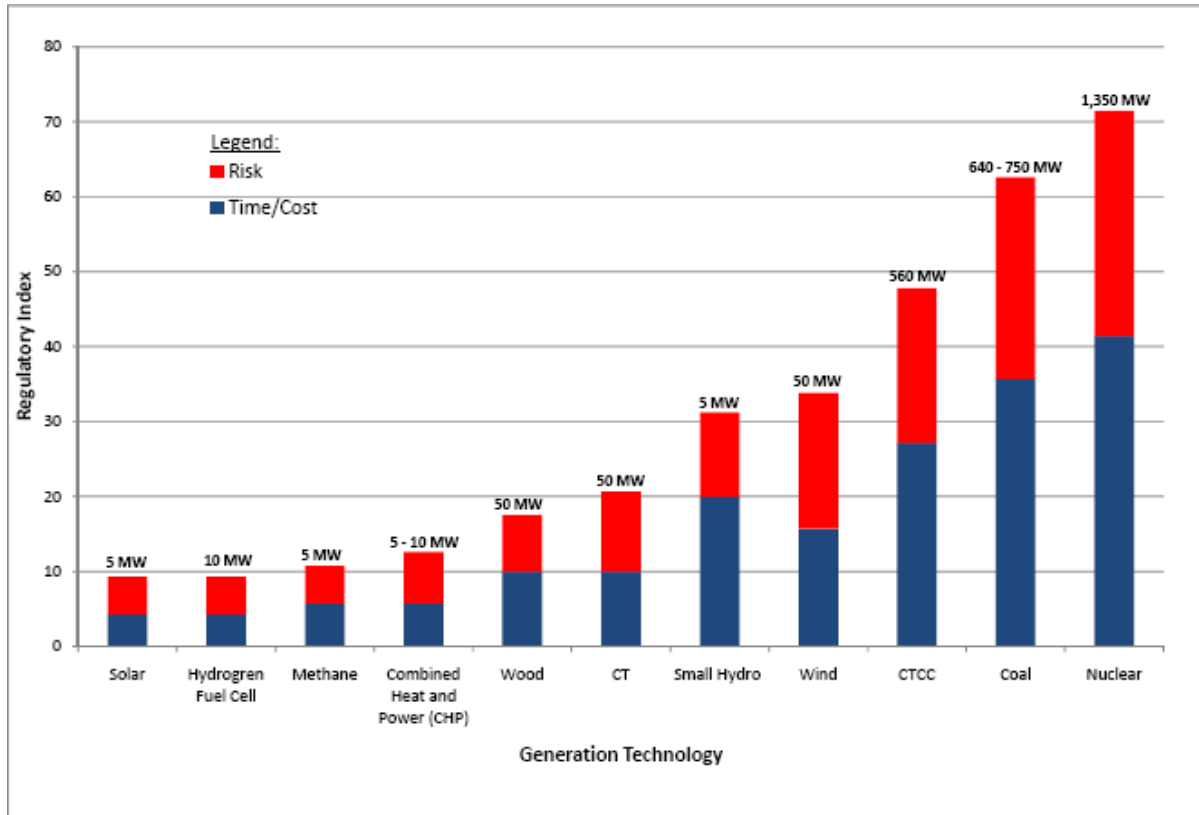


Figure 5.1 – Summary Index of Relative Regulatory Risk by Generation Technology.

Table 5.1 on the following page provides a summary of the key resource issues, public priorities, and regulatory timeframes associated with each technology. These issues, and the specific regulatory approvals required for each technology are described in more detail in Sections 5.2, 5.6 and Appendix A.

Table 5.1 – Key Regulatory Considerations by Technology.

Technology	Key Resource Issues	Public Priorities ⁸	Regulatory Timeframe (years)
Solar	None	4	<1
Hydrogen Fuel Cell	None	No data	<1
Methane	<ul style="list-style-type: none"> ▪ Air Emissions 	6	<1
Combined Heat and Power	<ul style="list-style-type: none"> ▪ Air Emissions ▪ Fuel Delivery and Storage 	No data	1
Wood	<ul style="list-style-type: none"> ▪ Air Emissions ▪ Fuel Delivery and Storage 	5	1-2
Small Hydro	<ul style="list-style-type: none"> ▪ Water Quality and Quantity ▪ Fisheries ▪ Recreation 	3	3-5
Wind	<ul style="list-style-type: none"> ▪ Aesthetics ▪ Wildlife ▪ New Transmission 	2	2-3
Combustion Turbine (liquid and/or gas)	<ul style="list-style-type: none"> ▪ Air Emissions ▪ Fuel Delivery and Storage 	9	1
Combustion Turbine Combined Cycle (gas)	<ul style="list-style-type: none"> ▪ Air Emissions ▪ Cooling Water Intakes and Discharge ▪ New Transmission 	7	1-2
Coal	<ul style="list-style-type: none"> ▪ Air Emissions ▪ Cooling Water Intakes and Discharge ▪ Fuel Delivery and Storage ▪ Aesthetics ▪ New Transmission 	10	3-5
Nuclear	<ul style="list-style-type: none"> ▪ Cooling Water Intakes and Discharge ▪ Waste Storage and Disposal ▪ Aesthetics ▪ New Transmission 	8	>10

⁸ Based on results of *Vermont's Energy Future: Public Engagement Process*. Numbers represent priorities in order from highest to lowest, with "1" being the highest priority in response to the following question: "Which resource options do you think should be the highest or lowest priorities to meet Vermont's future electricity needs considering all factors (cost, environmental attributes, reliability, etc.)". The highest priority (1) was energy efficiency.

5.2 Development Cost versus Regulatory Risk

Interestingly, the results of the permit analysis generally suggest an inverse relationship between the degree of permitting risk, and the expected unit cost of construction and operation on a per MWh basis. This relationship is shown graphically in Figure 5.2 below where the green bars reflect cost on a \$/MWh basis and the light blue bars reflect an index of relative regulatory risk where higher scores reflect greater environmental issues and public concerns.

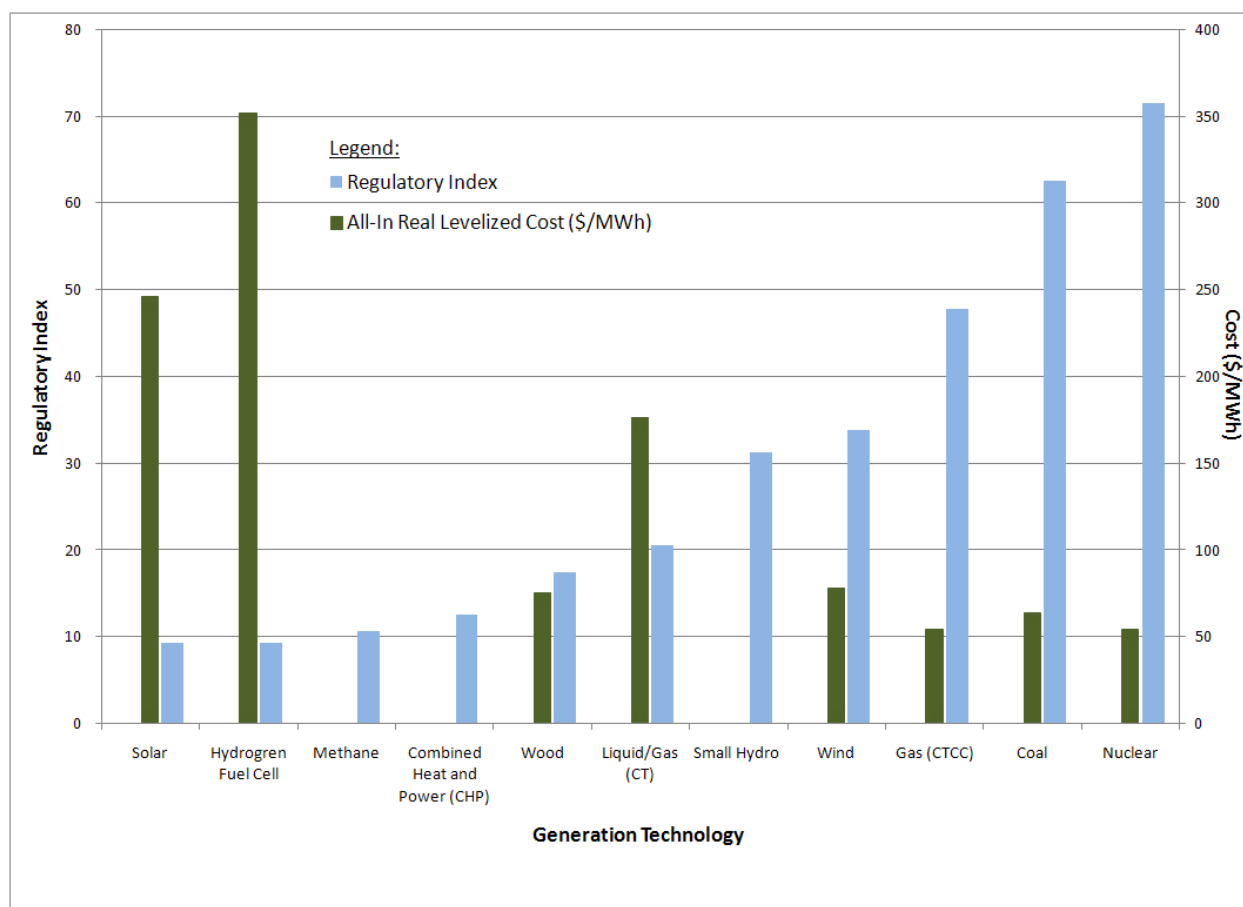


Figure 5.2 – Relationship between Relative Regulatory Risk⁹ and Construction, Operation, and Maintenance Cost¹⁰

⁹ Regulatory risk is reflected using an index where higher scores indicate greater environmental issues

¹⁰ Costs are taken from *Vermont Utilities Technical and Cost Issues of Generation Alternatives – Phase One Report* and reflect the “All-in Realized Cost” defined as the annual payment that would have to be made over the life of a given plant, after adjusting for inflation, in order to pay for all of the plant’s capital and operating costs, including emissions costs. Value is expressed as \$/MWh in \$2008. This value does not include pre-construction, permitting or design costs. Levelized costs for combined heat and power, methane, and small hydro are not shown, because these technologies were not evaluated in the Phase 1 Report.

While nuclear and coal technologies may be the least cost options from a pure internal or “private” cost and development perspective, they have the highest risk in terms of environmental impacts and permitting. Obtaining approvals for these technologies would increase the ultimate cost per/MWh and could involve expenditures for a project that may never be approved, or may not be economical once the permit conditions are factored in. Conversely, solar and fuel cell technologies would be relatively easy to permit, but are projected to be very expensive in terms of cost per MWh. Wood and wind technologies both represent a balance of relatively moderate regulatory risks and moderate power costs. Cost estimates were not developed for methane or CHP technologies in the Phase 1 report so the relationship between cost and likely regulatory risk can not be compared here, but the balance would likely be similar to that for wood and wind power.

5.3 Factors Affecting Regulatory Costs and Risk

The primary factors affecting regulatory costs and risks are:

1. *Electrical transmission* requirements, particularly the need for new transmission facilities or significant upgrades to existing facilities;
2. *Fuel delivery and storage*, including requirements for new infrastructure such as Gas pipelines or impacts on traffic and roads;
3. *Potential for environmental impacts* including impacts to air, water, and/or listed species or use of public lands, and;
4. *Complexity of the regulatory proceedings* and potential public opposition.

Locating generation in areas that are already developed for an industrial use, if possible, can reduce the issues and challenges associated with the above factors and significantly reduce regulatory costs and risks. New generation that entails the disturbance of undeveloped lands is typically much costlier and riskier. Advantages of developed sites include:

- Lower probability of encountering sensitive environmental resources;
- Consistency with existing land use and local development patterns, and;
- Potential for re-use of existing infrastructure including roads, storage tanks, rail lines, and transmission.

Permit approvals and conditions for new generation facilities are very sensitive to site specific characteristics. For example, a site located in a low-lying area with considerable wetlands and/or floodplains will involve a more rigorous regulatory review, greater mitigation requirements or other conditions, and a generally lower probability of being approved (at least not without significant adjustments, mitigation and accommodations for environmentally sensitive resources). Similarly, a site located within the National Forest would require additional Federal permits that would not be necessary if the development were located entirely on private lands.

The size of the project, in terms of overall footprint, and the location of the project relative to potentially sensitive resources such as wetlands, important viewsheds, or species of special concern have a significant impact on the regulatory review and its

outcomes. Larger projects tend to have a greater probability of encountering environmental issues and tend to attract a greater level of public and regulatory scrutiny. Other characteristics associated with the technology, such as requirements for cooling water, expected air emissions, or location near existing or planned electric or gas transmission facilities also act as key differentiating factors.

Two general conclusions arise from the above observations:

1. Generation projects that can be located on developed sites will be less costly, take less time, and be less risky from a regulatory approval perspective. They also are generally less costly from an overall site development perspective, by as much as two-thirds.
2. Nuclear, coal, and wind technologies have higher regulatory costs and risks because they typically require undeveloped properties due to their larger land and infrastructure requirements (i.e. bigger footprint).

Key regulatory considerations and the challenges associated with each are briefly discussed below.

Electrical Transmission - Locating new generation in areas served by existing transmission lines significantly reduces the overall costs and regulatory risks. Projects which require new transmission lines would require a separate review for the generation and the transmission facility. In addition, new transmission development could trigger federal approvals through the FERC, further increasing regulatory costs and risks. One of the biggest challenges for wind generation in Vermont is the common need for new electrical transmission lines. For the purposes of this study, it is assumed that any new generation greater than 400 MW would require new electrical transmission. It is further assumed that new transmission would be required to support utility-scale wind developments due to the remote nature of areas considered feasible for development.

Fuel Delivery and Infrastructure – Delivery of fuel can result in potential environmental issues and other regulatory concerns. Trucking fuel such as wood, diesel, coal, or uranium can trigger concerns about impacts to local roads as well as traffic and public safety. Trucking also entails burning fossil fuels and contributes to GHG emissions. Delivery of gas requires pipelines. Similar to transmission, a project that requires a major new gas pipeline would entail obtaining regulatory reviews and approvals for both the generation and the pipeline. Other infrastructure issues include the need for fuel storage, emissions stacks, and water intake and discharge facilities, including the need for water and wastewater treatment.

Air and Water – One of the most critical issues in siting any type of new development is the project's need for, and/or potential to adversely affect air or water resources. Generation facilities that involve combustion technologies, particularly those that involve fossil fuels face more significant costs to mitigate for air pollutants emissions. These costs may be in the form of Best Available Technology (BAT) requirements and/or operational constraints (whether voluntary to avoid the need to install emissions controls, or imposed by regulatory action). Concern regarding Green House Gas (GHG) emissions

has significantly increased the challenges associated with fossil fuel generation. Vermont's participation in the Regional Greenhouse Gas Initiative (RGGI), an effort to develop a multi-state cap-and-trade program covering greenhouse gas emissions, further increases the regulatory cost of carbon based fuels.

Projects that potentially affect waterways have to comply with numerous State and Federal regulations designed to protect water quality and aquatic resources, including control of point and non-point discharges such as stormwater. Assessing the potential for aquatic resource impacts, particularly if large volumes of water are involved, often requires extensive data collection and analyses that can be time intensive and costly. Collection and analysis of this data may involve multi-year studies to capture seasonal differences, multiple species, or life stages. The results of these studies can also be uncertain and represent opportunities for disputes. Generation technologies that require cooling water, such as nuclear and coal must obtain a National Pollution Discharge Elimination Systems (NPDES) permit in accordance with the federal Clean Water Act. This typically requires time consuming studies of potential water intake impacts on aquatic organisms as well as the impact of warm water discharges on the aquatic ecosystem of the receiving water. If a project affects wetlands, additional approvals are required. Depending on the size of the project, approval from the U.S. Army Corps of Engineers can be involved in obtaining a Wetlands and Waterways Dredge and Fill Permit. Hydro projects specifically require federal approval through the FERC because of their use of navigable waterways. Obtaining a FERC hydropower license is a very involved and complex process as described further in Section 5.6.

Generation that potentially affects air and water resources, such as a coal technology involves many State, Federal, and public reviews, the outcomes of which may not be consistent or may be disputed and contested.

Presence of Listed Species and Public Lands - Projects that have the potential to impact species (plants or animals) that are protected by State or Federal regulations (including species protected by the Federal Endangered Species Act) will trigger additional regulatory reviews requiring additional study, more time, higher mitigation requirements, and greater potential for opposition. Projects that require more land or involve undeveloped lands, such as wind farms typically have a higher likelihood of encountering sensitive species issues. Projects that have significant water needs such as hydro, coal, and nuclear technologies also tend to have a higher probability of impacting sensitive species. Projects that involve use of public lands (State or Federal), including lands administered by the U.S. Forest Service require additional permits such as a Federal Special Use Permits (SUP). These permits frequently include conditions to protect resources, including visual resources. Vermont recently adopted legislation that specifically prohibits development of wind farms on state owned lands (<http://www.vermontwindpolicy.org/decpresrel.pdf>).

Complexity of Regulatory Proceedings and Potential Public Opposition – The nature and extent of the regulatory proceeding has a very large impact on cost, time, and overall risk. Quasi-judicial hearing processes such as the PSB 248 process and the FERC hydropower

licensing process are complex, involving multiple parties, strict procedural filings, and public input. Interventions and disputes are common in these types of proceedings. Disputes can take time and resources to resolve and can be the basis for appeals and other legal challenges which add more time and costs to the process. Major Federal actions, such as issuance of a nuclear or hydropower license or approval of a major pipeline project, require compliance with the National Environmental Policy Act (NEPA) which can involve time consuming and costly environmental reviews. Public reviews and agency consultations also require time and resources. Significant public opposition can create barriers that make it difficult to obtain approvals.

5.4 Policy and Regulatory Coordination

In some cases Vermont's energy planning policies are not entirely consistent with its regulatory siting processes, particularly with respect to processes required to site and construct new power resources. These inconsistencies add additional complexities and challenges to the question of how to provide new generation within the state. The three most problematic policy and regulatory coordination issues relate to; (1) balancing statutory requirements related to energy and land use planning; (2) addressing the State's desire for renewable energy while simultaneously meeting requirements for "least cost integrated planning"; and (3) balancing generation with transmission planning to address system reliability. These three issues are briefly summarized below.

Energy and Land Use Planning – A recent study conducted by the Vermont Law School; *Energy and Land Use: Merging the Regulatory Streams* specifically examines issues related to Vermont's energy and land use statutes, and the impact of these issues on energy planning and siting in the state. The study notes that Title 30 Sections 248 and 218c, the two main statutory tools for reviewing proposed electricity and transmission projects, are not entirely complementary in terms of planning energy projects. The study specifically notes:

Section 218c is not as detailed as Section 248, and it does not require consideration of all of the factors that are found in Section 248. Thus, in practice, a new generation proposal may be consistent with a utility's Section 218c plan, but it might not be able to receive a CPG from the Board. A related issue is that Section 248 is focused on review of need, which is often driven by the real world judgment of what type of resources currently exist, the magnitude of electricity demand that is in place, and the impact of both of those factors on reliability. If an applicant demonstrates that current demand exceeds resource capacity, it is very difficult for the Board to deny a proposed project. Under the current system, the PSB reviews projects separately and sequentially, and it may reject one project after another as electric demand rises. At a certain point, the Board is compelled to approve the next proposed project, even if an earlier alternative would have been a better choice for the public good.

The study further concludes that the current regulatory environment could result in either: (1) financial or land use impacts that could have been avoided with better comprehensive planning; or (2) projects becoming stuck in expensive and lengthy administrative proceedings which could result in the unnecessary reliance upon out-of-state energy sources that might have higher financial or environmental costs. Among the potential solutions identified by the Vermont Law School study, it proposes an “open season-portfolio review” as one technique for bringing multiple projects before the PSB such that trade-offs could be more explicitly evaluated and a more comprehensive decision making process could be conducted.

Renewable Energy Development and Least Cost Planning – In 2005 the Vermont General Assembly passed Act 61 establishing a state energy policy which promotes the development of renewable energy projects including incentives through the Sustainably Priced Energy Enterprise Development (SPEED) program.¹¹ Several other policy documents including recent work by the Vermont Public Interest Research and Education Fund (VPIREF) and the Governor’s Commission on Climate Change also feature renewable energy as a critical component of Vermont’s future. In addition, the recent state public engagement process, Vermont’s Energy Future, indicates a clear public preference for small, renewable generation. Title 30 Section 218c(b), which governs utility planning and requires the development of individual Integrated Resource Plans (IRP), requires that utilities pursue least cost options which will minimize economic and environmental costs and risks. By and large, renewable energy sources including wind and solar are more expensive on a per MWh basis than other generation facilities. From a permitting perspective, this creates a challenge with regard to the Section 248 process and the issuance of a Certificate of Public Good (CPG) because the Public Service Board (PSB) is required to consider consistency with Integrated Resource Plans (IRP) and potential cost implications which may not ultimately be consistent with State policies to promote renewable energy development.¹²

Generation, Transmission Planning and System Reliability - Concerns within the state regarding proposed transmission projects, interest in potential non-transmission alternatives, and the need to maintain system reliability, have resulted in the creation of the Vermont System Planning Committee (VSPC). The VSPC is charged with exploring transmission planning over 10 and 20 year horizons. It is very difficult to separate issues of generation and the siting of new generation facilities from the issue of transmission and system reliability. In many cases, the selective siting of new power resources can serve to defer or avoid transmission or distribution projects. Conversely, the state of the transmission system can directly affect options for siting new generation and the costs

¹¹ The SPEED Program builds upon the policies first introduced as a result of the adoption of the Public Utility Regulatory Policies Act of 1978 (PURPA), as implemented in Vermont pursuant to PSB Rule 4.100, which mandates the purchase of power from “qualifying facilities” at full avoided cost rates regardless of a utility’s need for such resources.

¹² Similarly, the existence of PSB Rule 4.300 governing the SPEED Program and PSB Rule 4.100 implementing PURPA create opportunities for renewable project developers to seek the highest available rate for their project’s output thereby leveraging the system in a manner inconsistent with the utility’s obligation to seek the acquisition of least-cost power under Section 218c.

associated with these options. In many cases, new generation may require upgrades to existing transmission or distribution facilities, or the construction of new infrastructure.

From a permitting standpoint, it may be difficult for the PSB to assess the potential affects of a particular generation facility in the absence of information regarding transmission planning (which is required under 30 V.S.A. § 248(b)(10)). While this issue does not represent a direct conflict per se, it reflects ongoing parallel planning initiatives that should be coordinated in some way. This report does not directly address issues of permitting new transmission facilities. However, many of the same regulatory processes and challenges outlined for new generation also apply to transmission projects. Ultimately, any new large-scale generation facility would have to be planned in concert with related transmission infrastructure planning. Portions of the existing transmission systems that serve the state are highly constrained and may strongly influence new generation options, particularly with regard to the location of those options.

5.5 Public Engagement Process

The Vermont legislature tasked the Department of Public Service to conduct a comprehensive, statewide public engagement process on energy planning focused on the State's energy supply choices. A series of regional workshops, deliberative polling events, and online conferences were organized to disseminate information, and engage a broad range of public stakeholders.

Deliberative polling exercises were employed to obtain public opinion data for various energy future scenarios. An overarching theme that emerged from the public engagement process was a great concern for the environment, and the effects of energy decisions on global climate change.

Participants were asked a series of questions related to energy choices in Vermont. Specific areas of public concern relevant to this study are:

- *Environment* – strong concern for the environment particularly air pollution and greenhouse gases.
- *Renewable Energy Sources* – 94% of participants believed that Vermont should obtain the majority of its energy from renewable sources.
- *Size* – 70% preference among participants for smaller decentralized generation relative to centralized generation.
- *Resource Prioritization* – wind, solar, and efficiency were seen as extremely friendly to the environment; methane, hydro, and wood as slightly less but still very friendly; nuclear and natural gas as somewhat unfriendly; and coal and oil, in that order, as extremely unfriendly.

Additional information on the results of the public engagement process efforts is available at <http://www.vermontenergyfuture.info/>.

5.6 Assessment by Generation Technology

The following provides a summary discussion of the key regulatory issues and challenges associated with each of the generation technologies considered in this report. A relative comparison of the various regulatory processes and is provided in Table 5.1. Detailed descriptions of the key regulatory processes are provided in Appendix B. Additional information and analysis regarding regulatory processes timeframes, costs, and risks related to each technology is provided in Appendix A.

A key underlying issue for all of the technologies is not so much whether one can or cannot obtain permit approvals for certain projects, but if the conditions associated with such approvals would threaten the economic viability of the project.

Solar

For the purpose of this study, solar technology is assumed to involve the use of photovoltaic cells. From a public acceptance standpoint, solar technology is considered to be relatively easy to permit and is wholly consistent with state policies to promote renewable energy. The most significant issue from a regulatory approval perspective related to solar would be the land requirements and potential esthetic issues. Information from the U.S. Department of Energy, National Renewable Energy Lab indicates that a 5 MW solar installation would require 30-35 acres of cleared land. Depending on the location of the proposed project, such clearing could present concerns, but such issues would not likely be insurmountable.

Hydrogen Fuel Cells

Fuel cell technology, like solar, is considered renewable under the Vermont SPEED program and would be consistent with state energy policies. The technology has very few adverse environmental impacts and is thus considered relatively easy to permit. It is not anticipated that the pursuit of hydrogen fuel cell technology would present any significant permitting hurdles. The biggest potential environmental concern with fuel cells would likely be the transport and storage of hydrogen, which could be a safety concern depending on the size and location of the facility. On-site storage of hydrogen in tanks could present esthetic concerns, but these could likely be addressed through careful siting and design.

Methane

Methane projects could include landfill methane or farm methane (digestion of cow manure to produce methane gas). At a utility scale, farm methane would entail constructing digesters at individual farms and either burning the methane on-site or collecting the methane for energy production at a centralized location. Opportunities for landfill methane are limited, but are generally considered to be relatively easy to permit. Farm methane projects are also generally easy to permit and are supported by the state's SPEED program. Burning of methane helps to reduce greenhouse gases and thus is consistent with State policies regarding such. The PSB has approved several farm methane projects over the past couple of years.

Combined Heat and Power (CHP)

Combined Heat and Power is considered to be an efficient means of capitalizing on existing heating sources to generate power, or vice versa. Because such systems are generally associated with existing, or proposed institutional (e.g., educational and health care facilities), commercial or industrial sites and uses, they are relatively easier to permit. CHP technologies also generally garner positive public acceptance and are consistent with state policies to support small, distributed energy sources, particularly if they rely on renewable fuels. From a regulatory perspective, the most significant concern associated with CHP would be potential for air emissions. The level of emissions associated with a CHP would depend on the quality of the fuel, particularly the sulfur content, and the proposed operation of the unit(s). In general the emissions from a CHP facility would be less than the combined emissions from an independent power source and heat source. Post combustion controls can be added as required to meet air permitting requirements. The other concern associated with CHPs can be fuel delivery and storage which can adversely impact traffic, local roads, and esthetics. Use of renewable fuels, particularly wood can involve significant volumes of material that need to be trucked and stored on-site. Liquid fuels require storage tanks that require space and can be unsightly.

Wood

Wood burning technologies, including Stoker and Circulating Fluidized Bed (CFB) technology would likely encounter some potential difficulties associated with air emissions, water consumption, and concerns regarding indirect effects associated with harvesting and transporting the fuel. The primary difference between Stoker and CFB technologies would be in the air emissions. Stoker technology involves more emissions and thus likely requiring more control technology.

Both Wood Stoker and CFB technologies would require cooling water. Potential impacts on water resources including concerns regarding impacts on fisheries associated with water intakes and warm water discharges would trigger additional regulatory reviews and approvals which add costs, time, and risk to the project.

Fuel delivery and storage can also be an issue. Because wood has a higher moisture content than other fuels, larger volumes of fuel need to be transported and stored. This can have adverse impacts on traffic and roads if trucks are used for transport. Ultimately each project and site has a unique combination of fuel delivery and storage related variables and challenges. Examples include:

- **Fuel Source** – the source of wood fuel will determine the amount of processing and delivery requirements. Material obtained in pulp or chip form can be packaged and delivered in higher density than material obtained from natural harvest and would be anticipated to require fewer delivery trips for the same volume of usable fuel.
- **Delivery Method**- the location of the potential fuel supply in relation to generation will dictate the nature and complexity of transportation logistics. Wood fuel

obtained from timber harvest will need to consider transportation related issues at the source and destination. On the other hand with proper planning generation can be sited to simplify and facilitate fuel delivery (i.e., near commercial timber stands). Other critical delivery related characteristics include the mode of transport (truck, rail), changes in traffic volume, intensity and timing.

- **Storage Requirements**– Factors such as wood type (species) growing conditions, health at harvest, and form (chips, timbers) contribute to storage requirements. Fuel with high moisture content may require stock-piling areas to allow for proper seasoning. Additionally maintaining appropriate levels of fuel to ensure the availability and reliability of wood generation would need to be considered with respect to spatial and accessibility constraints.

From a policy perspective, wood may be easier to permit than other technologies such as gas or liquid fuels because it represents an indigenous resource within the state which is sustainable and in relative abundance for a limited number of commercially-sized projects. However, a 50 MW wood burning plant would require a fairly large footprint, particularly accounting for fuel storage, and a smoke stack that could make approval difficult in terms of esthetics and potential local opposition, depending on the location of the plant. Also, as noted in the Phase 1 report, significant expansion of Vermont's use of wood at the scale of many tens of megawatts could stress the region's sustainable wood supply, potentially putting upward pressure on prices and competing with other uses of wood chips. This could be a consideration in the Section 248 evaluation of economic benefits to Vermont.

Small Hydro

For the purposes of this analysis, small hydro is assumed to be less than 5 MW, though to a large degree the MW size is often less of a determining factor from an environmental perspective than the specific location and configuration of the proposed project. In many cases, "small" hydroelectric projects can have environmental impacts that are greater than larger hydroelectric projects.

Regardless of the MW size of the project, most hydroelectric projects would require securing a license, or license exemption, from the Federal Energy Regulatory Commission (FERC). The FERC licensing process is a fairly involved process that typically takes a minimum of two years to complete, and often involves up to five years or more depending on the nature of the project and the environmental concerns.

In addition to FERC approval, the state must approve a 401 water quality certificate for any hydro project. This often involves consideration of water quality as well as water quantity considerations in terms of instream flows and protection of fish, wildlife, and recreation resources. Federal resources agencies, particularly the U.S. Fish and Wildlife Service also maintain mandatory conditioning authority under the Federal Power Act for projects licensed by the FERC. The key resource concerns associated with small hydro are typically: fisheries; water quality; and recreation.

From an overall regulatory perspective, small hydro represents a medium to high risk, depending on the nature and location of the proposed project. Small hydro is not a technology that can be permitted quickly because it inherently involves utilization of a public resource. The regulatory proceeding is complex with extensive consultation requirements and numerous opportunities for interventions and appeals. Approvals frequently come with conditions (including operational conditions) that can make a project uneconomical. Past hydropower proposals in Vermont as well as other northeastern states have had significant difficulties obtaining workable 401 certificates.

The regulatory risk is much higher if the proposed project involves construction of a new dam. Permitting projects which utilize existing infrastructure such as old mill dams or that do not require a dam, such as an instream hydrokinetic project, would generally be easier. Small hydro also qualifies as a SPEED resource.

In addition to requirements to construct new hydropower resources, existing licensed hydropower projects must be relicensed after a period of time, generally every 30 years. Relicensing is a time and resource intensive undertaking that frequently results in additional license conditions and mitigation requirements. Additional operational constraints are commonly imposed in relicensing, including additional instream flow requirements and requirements to operate in a run-of-river mode. Such conditions can, and have reduced the energy capacity at existing hydropower sites in Vermont and elsewhere in the northeast. There is a potential for further reductions in overall hydropower capacity in the state as older hydropower facilities are relicensed over time.

Development of new hydropower in the northeast, even where there are existing dams and other infrastructure has been very difficult and generally resulted in considerable opposition from environmental organizations and the public. Projects that do not involve impoundments such as hydrokinetic technologies may face fewer regulatory challenges.

Wind

The development of wind power in Vermont has been the subject of considerable public debate and analysis. In 2002, the Department of Public Service (DPS) conducted the Wind Siting Consensus Building Project resulting in the *Wind Energy Planning Resources for Utility-Scale Systems in Vermont* which summarizes issues and information related to siting utility-scale wind power. In 2003, DPS followed up with a reconnaissance level assessment of wind power potential in *Estimating the Hypothetical Wind Power Potential on Public Lands in Vermont*. In 2004, Governor Douglas created the Commission on Wind Energy Regulatory Policy to develop recommendations regarding the application of the Title 30 Section 248 process for commercial wind generation.

Several recent and ongoing wind farm proposals present the opportunity to assess common regulatory issues associated with wind power development in the state. These projects include: the recently approved UPC Vermont Wind project in Sheffield, VT for 40 MW (Docket 7156); the East Haven project which was ultimately denied a CPG (Docket 6911); the Deerfield project (Docket 7250), which proposes to install up to 45

MW and is in the process of being reviewed by the PSB; and the Grandpa's Knob (50 MW proposed) and Equinox (9 MW proposed) projects which are in the early stages of planning and development.

PSB review of the UPC Vermont Wind project took approximately 18 months and involved 35 witnesses at ten days of evidentiary hearings and hundreds of oral and written comments from the public amounting to thousands of pages of testimony, exhibits, and transcripts (Docket 7156). The PSB found that the project would result in significant environmental impacts (primarily to esthetic resources), but issued a CPG (with conditions) based on the overall finding that the project would promote the general good of the state.

The East Haven project involved over two and a half years of review and testimony before the PSB, and ultimately the project was denied a CPG. The primary reason for the denial was the petitioner's failure to provide the studies necessary to make findings and reach a conclusion under Necessary Wildlife Habitat. Comparing and contrasting the UPC and East Haven projects provides an indication of the challenges and risks associated with siting wind farms and the importance of site location.

The Deerfield Wind project filed for a CPG in January 2007. The project is still being reviewed by the PSB.

Despite its distinction as a renewable energy source which has considerable public and policy support, wind technology is not without its challenges from a regulatory perspective, as evident in recent PSB dockets. The primary issues and concerns associated with wind technologies are:

- Esthetics;
- Wildlife impacts, particularly birds and bats, and;
- Transmission issues (wind projects tend to involve remote sites with limited existing infrastructure).

Vermonters place a very high value on scenic quality, viewshed protection, and the preservation of open space. Because the best wind sites are on ridgelines, and because wind turbines are typically very tall and require numerous towers spread over large areas, wind projects often result in significant landscape level visual impacts. The public is divided on the acceptability of these impacts. Results of the DPS's recent public engagement process indicate that some members of the public feel wind turbines do not blight the landscape and represent an acceptable trade off given other energy choices. Potential impacts of wildlife depend largely on the location of the proposed wind farm. Wildlife surveys are typically required, both at the planning stage and typically as part of post construction monitoring requirements. These studies add expense and add time to the project.

Combustion Turbine (CT) (liquid and/or gas)- Peaking

For the purposes of this study, it is assumed that new simple cycle combustion turbine projects in Vermont would be developed to provide peaking capacity and would be

designed to have dual fuel capability (natural gas and liquid fuels), for locations close to existing natural gas pipelines. If gas is not available, it is assumed the CT would run strictly on liquid fuel.

The primary regulatory issue for both gas and liquid fuel is potential air emissions, including nitrogen oxides and greenhouse gases. Burning natural gas would result in fewer emissions per MWh than liquid fuels which would allow for more run hours. Liquid fuels also present potential issues relative fuel delivery including truck traffic and the need for storage tanks, both of which create potential permitting issues. The relative risk of regulatory approvals for CT projects would likely depend largely on the site specific characteristics of the location, whether it is at an existing facility, and the proposed operation of the facility. Permitting conditions for internal combustion engines would be similar to those of a straight cycle combustion turbine.

Siting new combustion turbines or reciprocating engines at an existing developed site would significantly reduce the potential environmental and permitting issues over siting such facilities at an undeveloped location.

Combustion turbines could also be run on bio-fuels, including methane. This capability and flexibility is an advantage from a policy and public acceptance perspective which could reduce the attendant regulatory risks.

Gas-fired Combustion Turbine Combined Cycle (CTCC) – Intermediate or Baseload
Combined cycle technology utilizes waste heat from a CT to create steam to power a second turbine generating electricity. This technology is relatively efficient providing opportunities to operate as an intermediate or base load resource. However, such a facility would be expected to run thousands of hours a year (as opposed to hundreds of hours for a straight peaking CT), which may result in more air pollutants or control technology requirements, even though gas produces fewer emissions on a per/MW basis compared to liquid fuel. In addition, because of the steam process, CTCC technology at the scale examined in this report (560 MW) would require significant volumes of water for cooling¹³. Permitting water withdrawals and wastewater discharges require additional permit approvals and associated analyses. Water and wastewater treatment plants would also be required increasing the overall project footprint and increasing regulatory risk. The regulatory requirements for smaller MW facilities would be similar; however, mitigation requirements could be less for smaller water withdrawals and discharge volumes.

As noted above for CT technologies, siting a CTCC unit at an existing developed site would significantly reduce the difficulty and risk related to permitting, particularly if the facility already has infrastructure, including access to an existing pipeline. If a natural gas-fired generation project were proposed in an area already served by a gas pipeline, only one set of permitting issues would arise. However, if a new gas pipeline were needed, this would trigger additional 248 reviews for the pipeline as well as federal

¹³ Alternatively, dry cooling (which is more costly in terms of initial capital cost and operating efficiency) could be utilized.

approvals through the FERC potentially increasing attendant permitting risk. For the purposes of this study, it is assumed that CTCC technology would be located near an existing gas pipeline in the northern part of the state. This assumption is not meant to imply that new gas pipelines could, or would not be built in the future, but evaluating such an action would require site-specific information that is beyond the scope of this analysis.

Coal

The development of coal based generation in Vermont would likely be extremely difficult due to a combination of the relatively large footprint required; the potential for numerous adverse environmental and social impacts; the likely need for new transmission facilities; existing public policies that specifically discourage fossil fuel technologies; and public opinion that generally opposes such technologies. Coal technologies would also have indirect environmental impacts associated with the transport of fuel into the state, storage and treatment of that fuel, and the disposal of waste byproducts from production which would add to the challenges. We have estimated the regulatory risk index for coal generation technologies as large (i.e. high risk). Obtaining regulatory approvals would likely involve considerable opposition and a protracted process, with a high degree of uncertainty relative to outcome and the ultimate cost of approval and associated permit conditions. The factors noted above not only make it challenging to permit a coal plant, but also make it unlikely that a coal plant would actually be proposed in Vermont.

The Phase 1 Report examined three specific coal technologies; Integrated Gasification Combined Cycle (“IGCC”), Pulverized Coal, and Circulating Fluidized Bed (CFB). From a regulatory approval and environmental impact perspective, all three technologies would encounter similar issues. The IGCC and CFB technologies involve more complete combustion resulting in less air pollution which would likely make them easier to permit from an air emissions standpoint. IGCC technology could also be potentially air cooled, which would eliminate potential water resource impacts associated with cooling water intakes and discharges. The waste stream from the IGCC gasification process however, could make IGCC somewhat more difficult to permit than the other two coal technologies. CFB technology could be designed to burn bio-fuels in addition to coal, which could make it easier to approve from a regulatory perspective.

Nuclear

Development of a new nuclear plant in Vermont would be extremely difficult from a regulatory approval perspective. Nuclear scored the highest permitting index of all the technologies evaluated in this study. The perceived risk by the general public and waste stream are two significant factors unique to nuclear technologies. Other factors contributing to the high risk finding include the amount of land required to accommodate the relatively large footprint; security; cooling requirements which will involve either a large body of water or substantial cooling towers; and the esthetic impacts. The ongoing debate regarding the potential renewal of the Nuclear Regulatory Commission (NRC) license for the existing Vermont Yankee Nuclear Station provides a good indication of the regulatory and environmental issues that nuclear technologies are faced with in Vermont.

Obtaining approvals for a new nuclear station would likely take many years and significant resources in terms of environmental siting and studies. Section 248(e) of Title 30 specifically requires that the PSB obtain the approval of the general assembly before issuing a CPG for a nuclear facility. The factors noted above not only make it challenging to permit a nuclear plant, but also make it unlikely that a new nuclear plant would actually be proposed in Vermont.

6.0 CONCLUSIONS

Results from the Phase 1 and Phase 2 analyses suggest the following conclusions:

General Observations

- Permitting new generation and transmission facilities in Vermont is complex, involving multiple regulatory approvals and potentially lengthy proceedings. Very few new grid-connected generation facilities have been approved in Vermont in the past 20 years.
- Generation projects that can be located on developed sites served by existing infrastructure will likely be less costly, take less time, and be less risky from a regulatory approval perspective. They also are generally less costly from an overall site development perspective.
- Larger projects tend to have a greater probability of encountering environmental issues and tend to attract a greater level of public and regulatory scrutiny.

Transmission and Infrastructure

- Vermont's existing electrical transmission system was built to accommodate much lower loads than other areas in New England. These conditions present significant constraints on the siting of new generation.
- New generation of significant scale would likely require some level of local transmission facility upgrades. Larger generation projects (> 400 MW) would likely require major new transmission facilities that would increase costs, regulatory reviews, potential public opposition, and overall risk. Costs for new transmission could range from \$1-3 million per mile.
- Opportunities for natural gas generation are limited to the northern part of the state without major expansion of existing gas pipelines. Pipeline extension costs are on the order of \$1.5 million per mile depending on the pipe size and pressure. Non-firm natural gas supply (providing service for most of the year) could be feasible for small generating units, without significant gas transmission system upgrades.
- The Vermont Gas Service (VGS) system could accommodate (or be upgraded to accommodate) substantial gas-fired generating capacity. The required costs (and, therefore, the economic viability of new gas-fired capacity) would depend on the extent of system upgrades, if any, required within Vermont, and on the TransCanada Pipeline ("TCPL") gas transmission system which supplies Vermont. The required upgrades would depend greatly on the size of the power plant, its location on the VGS system, and whether the plant required firm year-round gas supply or (alternatively) could use oil as a backup fuel during times of high gas demand.

Generation Technologies

- Solar and fuel cell technologies would be relatively easy to permit and would contribute to the state's renewable energy goals, but would be very expensive to develop and could be cost prohibitive on a large scale.
- Methane, CHPs and wood represent relatively low to moderate development costs and permitting risks. These technologies all have the potential to contribute to the state's renewable energy goals and are reflective of general public interest in development of smaller-scale distributed generation that utilizes indigenous resources
- Wind and small hydro technologies both represent renewable generation, but face potentially difficult siting challenges that increase permitting time and risk. Both technologies have very specific siting requirements (i.e. must be located on ridgelines and in rivers) that typically involve sensitive resources and potential opposition. Suitable wind sites are also typically not associated with existing transmission infrastructure.
- Smaller capacity combustion turbines that could be sited at existing facilities and could burn liquid, gas, and/or bio fuels to meet peak loads would involve moderate costs and regulatory risks.
- Larger capacity combined cycle combustion turbine technology represents a low cost option for meeting intermediate and baseload needs, but would involve relatively large regulatory costs and risks, due in part to the likely need for new electrical transmission. Strategic siting of smaller combined cycle combustion turbines (on the magnitude of 100 to 200 MW as opposed to the 560 MW capacity plant evaluated in the Phase 1 Report) could significantly reduce regulatory costs and risks by avoiding major transmission investments.
- Nuclear and coal technologies represent least cost options from a pure development cost perspective, but have the highest risk in terms of environmental impacts, potential public opposition and permitting. Obtaining approvals for these technologies could increase the ultimate cost per MWh and could involve expenditures for a project that may never be approved, or may not be economical once the permit conditions are factored in.
- The development of new nuclear and coal-based generation in Vermont would be extremely difficult due to a combination of the relatively large footprints required; fuel transport and storage, the potential for numerous adverse environmental and social impacts; the likely need for new transmission facilities; existing public policies that specifically discourage fossil fuel technologies; and public opinion that generally opposes such technologies. Given these factors, it is unlikely that a new nuclear or coal plant would actually be proposed in Vermont.

APPENDIX A
REGULATORY INDEX ANALYSIS

APPENDIX A REGULATORY INDEX ANALYSIS

To compare and contrast various generation options a simplified ranking, or index of regulatory cost (including time) and risk was developed. The index utilizes a qualitative, non-linear scoring system based on the applicability of particular regulatory processes to the technology, the level of complexity and potential opposition that might be expected which affect timeframes and costs, and the overall risk profile. The index considers specific criteria used by the state's Public Service Board (PSB) in issuing a Certificate of Public Good (CPG) through the Section 248 process as well state and federal regulatory processes designed to protect environmental resources. The criterion used to score each of the generation technologies are described below. The scoring system developed for each of these criteria is presented in Table A1 on the following page.

- *Regulatory Risk* - Estimate of the potential for environmental issues of concern, opposition, and the likelihood of approval. For analysis of 248 criteria, the risk score indicates the likelihood that the criteria and any associated tests or standards would be met. For example, if a project is consistent with local and regional planning commissions, then a score of "10" would be applied under 248(b)(1) – Orderly Development. If the project is highly inconsistent with local land use directions, then a score of "30" or potentially "60" would be applied. Where a generation technology is expected to provide a significant societal benefit in addition to the production of electricity, negative risk scores may be awarded.
- *Regulatory Time/Cost* – Estimate of the time and costs required to obtain regulatory approval, including: consideration of procedural requirements and associated costs for evidence, testimony, and rebuttals; data and analysis requirements, potential appeals and/or legal challenges; and potential for onerous and costly permit conditions.

Where a generation technology is expected to provide a significant societal benefit in addition to the production of electricity, negative scores may be awarded. For example, if a technology qualifies for the SPEED program, it is given "- 20" under the risk category, which reduces the overall risk score. Similarly, secondary, or indirect economic benefits are expected to occur as a result of certain in-state developments such as Wood Technologies that would have a positive economic impact on timber harvesting. In these cases, a "-10" score is given under the economic benefit of the 248 process.

Table A1 – Scoring System for Regulatory Index

Score	Regulatory Risk	Regulatory Time/Cost
-20	SPEED- Technology qualifies for the SPEED program.	Not Applicable: Benefit accrued to risk. No influence on regulatory time or cost.
-10	Economic Benefit - Secondary, or indirect economic benefits are expected to occur as a result of the development.	Not Applicable: Benefit accrued to risk. No influence on regulatory time or cost.
0	Not Applicable: No risk.	Not Applicable: No time or cost.
10	Low: Little to no issues of concern. Denial very <u>unlikely</u> .	Low: Typically 6 months or less. Standard filing and processing costs. No hearings or public process.
20	Medium: Potential for some issues which can likely be addressed through project design, siting, and/or reasonable mitigation. Potential for some opposition with increased degree of uncertainty. Probability of denial less than 50%.	Medium: 6 months to 1 year. Increased filing and procedural costs.
30	High: Likelihood of significant regulatory issues and opposition with uncertain outcome. Probability of denial or unacceptable conditions 50% or higher.	High: 1 to 3 years. Potential for protracted proceedings, expanded field studies and analyses, onerous mitigation requirements and compliance filings, and appeals. Involves a major federal action requiring NEPA compliance.
60	Very High: Involves probable "show stopper" issues. Expect strong opposition from multiple fronts. Denial likely.	Very High: More than 3 years. Protracted legal proceedings and appeals likely. Likely to involve very expensive studies and analyses, significant mitigation costs and numerous compliance obligations.

Tables A2 and A3 shown on the following pages provide a summary of the regulatory index scores for each generation technology. Table A2 lists overall scores for state and federal approval processes, including the 248 process. Table A2 also provides overall index scores for each technology considering all of the regulatory approvals. These overall index scores are what are plotted in Figure 4.1 in the main body of the report. Table A3 lists scores for the individual evaluation criteria used in the Section 248 process. The rationale for each of the scores listed in tables A2 and A3 are provided in the Regulatory Risk Profiles presented following Table A3.

Table A2 – Summary of Regulatory Index Scores for State and Federal Approvals

Technology	SPEED Program ⁴	Clean Air Act	Stormwater	401	402 (316a & 316b)	404	Federal Power Act (FERC, ISO, NRC)	Summary Score	Phase 1 Report Costs (\$/MWh) ⁵	Notes
Methane										
Time/Cost	0	10	10	0	0	0	0	3		
Risk	-20	20	10	0	0	0	0	1		
Solar										
Time/Cost	0	0	10	0	0	0	0	2		
Risk	-20	0	10	0	0	0	0	(1)		
Hydrogen Fuel Cell										
Time/Cost	0	0	10	0	0	0	0	2		
Risk	-20	0	10	0	0	0	0	(1)		
Combined Heat and Power (CHP)										
Time/Cost	0	10	10	0	0	0	0	3		
Risk	0	20	10	0	0	0	0	4		
Small Hydro										
Time/Cost	0	0	10	30	0	10	60	18		
Risk	-20	0	10	30	0	10	30	9		
Wood										
Time/Cost	0	10	10	10	10	0	0	7		
Risk	-20	20	10	10	10	0	0	4		
Wind										Assumes new transmission needed
Time/Cost	0	0	20	0	0	10	20	7		
Risk	-20	0	20	0	0	0	20	3		
Gas										Assumes existing pipeline available
Time/Cost	0	20	20	10	30	20	30	19		
Risk	0	20	20	10	20	0	30	14		
Liquid Fuels										
Time/Cost	0	20	10	0	0	10	0	6		
Risk	0	20	10	0	0	0	0	4		
Coal										
Time/Cost	0	20	30	10	60	10	30	23		
Risk	0	20	30	10	30	0	30	17		
Nuclear										
Time/Cost	0	10	20	20	60	10	80	29		
Risk	0	20	20	20	30	0	50	20		

Table A3 –Regulatory Index Scores for Section 248 Process

Technology	248(b)(1) Orderly Development 2	248(b)(2) Need for Service	248(b)(3) System Stability and Reliability	248(b)(4) Economic Benefit to the State 3	248(b)(5) Esthetics, Historic, etc.	248(b)(6) Integrated Resource Plans	248(b)(7) State Electric Plan	248(b)(8) Outstanding Resource Waters	248(b)(9) Transmission Facilities	248(e) Nuclear Facilities	248 Total	Phase 1 Report Costs (\$/MWh) ⁵	Notes
Methane													
Time/Cost	0	0	0	0	0	0	0	0	0	0	20		
Risk	10	10	10	-10	10	10	10	10	10	0	70		
Solar													
Time/Cost	0	0	0	0	0	0	0	0	0	0	20		
Risk	10	10	10	10	10	10	10	10	10	0	90		
Hydrogen Fuel Cell													
Time/Cost	0	0	0	0	0	0	0	0	0	0	20		
Risk	10	10	10	10	10	10	10	10	10	0	90		
Combined Heat and Power (CHP)													
Time/Cost	0	0	0	0	0	0	0	0	0	0	20		
Risk	10	10	10	-10	20	10	10	10	10	0	80		
Small Hydro													
Time/Cost	0	0	0	0	0	0	0	0	0	0	30		
Risk	10	10	10	10	30	10	10	20	10	0	120		
Wood													
Time/Cost	0	0	0	0	0	0	0	0	0	0	30		
Risk	20	10	10	-10	20	10	10	10	10	0	90		
Wind													Assumes new transmission needed
Time/Cost	0	0	0	0	0	0	0	0	0	0	60		
Risk	40	20	20	20	60	20	20	20	30	0	250		
Gas													Assumes existing pipeline available
Time/Cost	0	0	0	0	0	0	0	0	0	0	60		
Risk	30	20	20	20	50	20	20	20	10	0	210		
Liquid Fuels													
Time/Cost	0	0	0	0	0	0	0	0	0	0	30		
Risk	30	10	10	10	30	10	10	10	10	0	130		
Coal													
Time/Cost	0	0	0	0	0	0	0	0	0	0	90		
Risk	60	20	30	20	90	20	20	20	20	0	300		
Nuclear													
Time/Cost	0	0	0	0	0	0	0	0	0	0	90		
Risk	90	20	30	20	60	20	20	20	20	60	360		

Regulatory Risk Profiles by Generation Technology

The following tables highlight the regulatory processes that would likely be key drivers for each generation technology considered. Estimated levels of regulatory time/cost and risk are shown in the tables below along with the rationale for each score. Only risk scores greater than “20” are shown. Regulatory processes not shown either do not apply, or their application would depend on the specifics of the situation and therefore cannot be assessed generically.

Methane, Solar, and Hydrogen Fuel Cell Technologies

These technologies would not be expected to experience any elevated level of regulatory risk beyond standard reporting and review unless there are site specific environmental issues involved.

Combined Heat and Power

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(5)	20	20	Due to the sheer number of environmental factors considered here, there is an elevated risk that the PSB or an intervener could raise issues requiring evaluation and/or mitigation. Issues for CHP may include esthetics, hauling traffic, storage, and noise and air pollution.
CAA	10	20	Compliance with air emissions standards could require modified operations or control technologies.

Small Hydro

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(5)	30	30	Due to the sheer number of environmental factors considered here, there is an elevated risk that the PSB or an intervener could raise issues requiring evaluation and/or mitigation. Issues for small hydro commonly include esthetics, fisheries and aquatic resources, and recreation.
248(b)(8)		20	Areas designated as Outstanding Resource Waters are provided special protection by the PSB which would inhibit development. Siting potential hydro projects outside of these limited areas would reduce or eliminate this risk.
CWA	30	30	Water quality certification under section 401 is required. Permit conditions affecting project operations are often prescribed in the certificate and reflect a potential elevated level of exposure and risk.

FPA	60	30	A FERC license would be required. This is a relatively lengthy process that exposes an applicant to interventions and likely permit conditions. Issuance of a FERC license also represents a major federal action triggering an environmental review in accordance with the National Environmental Policy Act (NEPA) which represents additional exposure.
SPEED	0	-20	Hydro technology is considered a renewable source of generation and qualifies for the SPEED program.

Wood Technologies

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	30	20	There is an elevated risk that the development of a wood burning plant and its associated infrastructure may be inconsistent with local or regional plans.
248(b)(5)		20	Due to the sheer number of environmental factors considered here, there is an elevated risk that the PSB or an intervener could raise issues requiring evaluation and/or mitigation. Issues for wood may include esthetics, hauling traffic, storage, and noise and air pollution.
CAA	10	20	Compliance with air emissions standards could require modified operations or control technologies, primarily for particulates.
SPEED	0	-20	Wood technology is considered a renewable source of generation and qualifies for the SPEED program.

Wind (Generation)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(5)	30	30	Concerns regarding potential esthetic impacts are very common with wind farms in Vermont. Concerns regarding potential wildlife impacts are also commonly raised in PSB proceedings. These issues represent potential points of exposure and risk of detailed studies and/or mitigation.
248(b)(10)		30	Due to their remote locations, wind farms typically require new transmission infrastructure. This represents an additional point of exposure.

SPEED	0	-20	Wind technology is considered a renewable source of generation and qualifies for the SPEED program.
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Wind (Transmission)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	30	30	Siting of transmission facilities to serve wind farms in relatively remote, undeveloped areas creates a relatively high likelihood that the development would be subject to an elevated risk of denial due to conflict with land conservation measures and recommendations made by legislative bodies and local and regional planning commissions.
248(b)(5)		30	Concerns regarding potential esthetic impacts are very common with transmission projects in Vermont.
FPA	20	20	Wind farms of 50 MW would require a system impact study by ISO. New transmission lines may also require FERC approvals. These regulatory reviews add time and cost to the project and reflect additional points of exposure to potential mitigation requirements. FERC approvals could also trigger an environmental review in accordance with the National Environmental Policy Act (NEPA).

Gas (Generation)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(5)	30	20	Due to the sheer number of environmental factors considered here, there is an elevated risk that the PSB or an intervener could raise issues requiring evaluation and/or mitigation.
CAA	20	20	Compliance with air emissions standards could require modified operations or control technologies.
CWA	30	20	Relatively high water demand. Permits required for water withdrawal and discharge, including 316(a) and (b) approvals for entrainment, impingement, and thermal impacts.

Gas (Transmission)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	30	20	There is an elevated risk that the siting of new transmission may be inconsistent with local or regional plans.
248(b)(5)		30	Concerns regarding potential esthetic impacts are very common with transmission projects in Vermont.
FPA	20	20	Gas plants of 560 MW would require a system impact study by ISO. New transmission lines may also require FERC approvals. These regulatory reviews add time and cost to the project and reflect additional points of exposure to potential mitigation requirements. FERC approvals could also trigger an environmental review in accordance with the National Environmental Policy Act (NEPA).

Liquid Fuels

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	30	30	It is probable that a proposed liquid fuel plant would not be consistent with local and regional plans and would encounter local opposition.
248(b)(5)		30	Potential for significant esthetic, historic, and/or natural resource impacts due to the size and nature of the technology. Likely opposition and a protracted proceeding relative to these issues.
CAA	20	20	Compliance with air emissions standards could require modified operations or control technologies.

Coal Technologies (Generation)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	60	30	It is highly likely that a proposed coal plant would not be consistent with local and regional plans and would encounter very strong local opposition.
248(b)(3)		20	One large generation facility is less reliable than a distributed generation strategy involving smaller facilities.

248(b)(5)		60	Potential for significant esthetic, historic, and/or natural resource impacts due to the size and nature of the technology and its requirement to be sited near a large body of water. Issues associated with delivery and storage of fuel would also be potential point of concern. Likely opposition and a protracted proceeding relative to these issues.
248(b)(10)		20	Due to the assumed capacity a new coal plant would require new transmission infrastructure. This represents an additional point of exposure.
CAA	20	20	Compliance with air emissions standards could require modified operations or control technologies.
Stormwater	20	20	Compliance with stormwater regulations will require development, operation and management of appropriate treatment systems.
CWA	60	30	Relatively high water demand. Permits required for water withdrawal and discharge, including 316(a) and (b) approvals for entrainment, impingement, and thermal impacts.

Coal Technologies (Transmission)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	30	30	There is an elevated risk that the siting of transmission to serve a new coal plant may be inconsistent with local or regional plans.
248(b)(5)		30	Concerns regarding potential esthetic impacts are very common with transmission projects in Vermont.
FPA	20	20	A large coal plant would require a system impact study by ISO. New transmission lines may also be necessary requiring FERC approval. These regulatory reviews add time and cost to the project and reflect additional points of exposure to potential mitigation requirements. Action by the FERC would trigger an environmental review in accordance with the National Environmental Policy Act (NEPA).

Nuclear Technology (Generation)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	60	60	It is highly likely that a proposed nuclear plant would not be consistent with local and regional plans and would encounter very strong local opposition.
248(b)(3)		20	One large generation facility is less reliable than a distributed generation strategy involving smaller facilities.
248(b)(5)		30	Potential for significant esthetic, historic, and/or natural resource impacts due to the size and nature of the technology and its requirement to be sited near a large body of water. Likely opposition and a protracted proceeding relative to these issues.
248(b)(10)		20	Due to the assumed capacity a new nuclear plant would require new transmission infrastructure. This represents an additional point of exposure.
248(e)		60	Approval from the VT general assembly required before a CPG could be issued. Such a process would likely be highly political with a very uncertain outcome. Potential “show stopper” issue.
CWA	60	30	Relatively high water demand. Permits required for water withdrawal and discharge, including 316(a) and (b) approvals for entrainment, impingement, and thermal impacts.
FPA	60	30	Nuclear Regulatory Commission licensing is a very involved and lengthy process with the potential for significant opposition and highly uncertain outcomes.

Nuclear Technology (Transmission)

Regulatory Review	Time/Cost	Risk	Rationale
248(b)(1)	30	30	There is an elevated risk that the siting of new transmission to serve a new nuclear plant may be inconsistent with local or regional plans.
248(b)(5)		30	Concerns regarding potential esthetic impacts are very common with transmission projects in Vermont.

FPA	20	20	A new nuclear plant would require a system impact study by ISO. New transmission lines may also be necessary requiring FERC approval. These regulatory reviews add time and cost to the project and reflect additional points of exposure to potential mitigation requirements. Action by the FERC would trigger an environmental review in accordance with the National Environmental Policy Act (NEPA).
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APPENDIX B
INVENTORY OF KEY REGULATORY PROCESSES

**Evaluation
Criteria**

Regulatory Test

Section 248

**248(b)(1) Orderly
Development of the
Region**

Regional and municipal planning agencies and local legislative bodies are provided an opportunity to review and comment on generation proposals under consideration by the PSB.

- a) *Regional Plans* - Vermont is divided into eleven regional planning areas each of which have a planning document outlining environmental and economic strategies for growth and development. Most plans have a dedicated energy section that identifies regional goals and policies related to energy conservation, generation, and transmission. Regional plans are available at the Vermont Association of Planning and Development Agencies (VAPDA) website <http://www.vapda.org/>.
- b) *Local/Municipal Plans* - Planning goals differ by municipality and not all municipalities have articulated development goals in plan form.

Strict consistency with plans is not required under Section 248.

**248(b)(2) Need for
Present and Future
Demand for Service**

Is the proposal a cost effective method to meet the need for present and future demand?
Requires analysis of the ability of energy conservation programs and measures and energy-efficiency and load management measures, to achieve the same objectives as the proposal. The Board may consider relevant factors including whether the project is least-cost using the societal test, rate and bill impacts and the feasibility of competing options.

**248(b)(3) System
Stability and Reliability**

Will the proposal adversely affect system stability and reliability?
Proposals must include consideration of additional capacity on the existing transmission system stability and reliability.

**248(b)(4) Economic
Benefit to the State**

Will the proposal result in an economic benefit to the state and its residents?
Requires the proposal to be economically viable and beneficial to state rate payers.

**248(b)(5) Aesthetics,
Historic Sites, Air and
Water Purity, the
Natural Environment
and Public Health and
Safety:**

These criteria cover a range of specific resources/concerns which are detailed below.

**1. Air and Water
Pollution**

Will the proposal adversely affect air and water purity?
A complete discussion of air purity and related permitting tests is provided as a separate table. Noise issues are also addressed under this criterion.
Specific consideration for water purity and the natural environment is given to the according to the following resources:

- a) *Headwaters* –Ground and surface water quality protection to; small watersheds, public water supply watersheds, watersheds above 1,500 ft, or aquifer recharge areas.
- b) *Waste Disposal* – Conformance with waste disposal regulations as well as potential fuel spill and stormwater management.

Evaluation Criteria Regulatory Test

Section 248

- c) *Water Conservation* – Efficient water use, consumption, and recycling practices are employed where practicable.
- d) *Floodways* – Flood flows and storage are not affected to endanger life, property, or peak discharge rates. Applicable to proposals within a floodway or floodway fringe.
- e) *Streams* – Protection of natural stream conditions. Applicable to proposals adjacent to streams and watercourses.
- f) *Shorelines* – Protection of natural shoreline conditions. Project must not impeded recreational access or use, provide vegetative screen from waters, and provide bank stabilization (where appropriate).
- g) *Wetlands* – Compliance with “Significant Wetlands” rules which outline activities that are allowable within the regulated wetland resource area. Regulated resource area is defined by the delineated edge of the wetland resource as well as an associated upland buffer. Default buffers are 50 feet around all Class 2 wetlands, and 100 feet around Class 1 wetlands.

2. Sufficient Water Availability Can existing water supply meet the project’s anticipated water demand?
Intended to ensure that water intensive proposals are feasible and will not cause undue adverse impacts on water supply. Applicable only if the proposal requires water use (e.g., cooling).

3. Burden on existing Water Supply Can water supply demand be met by existing supply system?
Intended to ensure that proposals do not place water supply improvement burden on existing supply systems. Applicable if the proposal will utilize shared water supply.

4. Soil Erosion Will the proposal cause soil erosion or alter the lands ability to retain water?
Intended to ensure that soil erosion and water storage functions are not affected to result in dangerous or unhealthy conditions.

5. Traffic Will the proposal impact transportation infrastructure or traffic patterns?
Considers the potential impact on congestion and unsafe conditions on highways, waterways, railways, airports and airways. Potential nexus is with fuel delivery traffic associated with generation.

6. Educational Services Will the proposal increase the demands on educational services?
Intended to ensure that existing educational services are not adversely impacted. This criterion is not generally applicable to generation proposals. However, a large generation facility that would require large full-time staff may need to consider these impacts.

7. Municipal Services Will the proposal place an unreasonable burden on the ability of the local governments to provide municipal or governmental services?
Intended to ensure that existing municipal services are not adversely impacted. This criterion includes consideration of the adequacy of existing emergency response service (e.g. fire, rescue, ambulance, police).

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<p>8. Scenic or Natural beauty, aesthetics, historic sites, rare and irreplaceable natural areas</p>	<p>Will the proposal change the scenic or natural aesthetics of the project area or vicinity? Particularly a concern for proposals that require vertical development (e.g., wind turbines and stacks). Proposals that include siting development at elevations above 2,500 ft require notification to municipalities within a 10 mile radius of the proposed structure.</p> <p>Is the project located on a historic site? Intended to provide protection for historic and cultural resources that might be affected by development. A listing of historic places and properties is maintained by the National Register of Historic Places http://www.nationalregisterofhistoricplaces.com/VT/state.html .</p> <p>Will the proposal destroy or significantly imperil necessary wildlife habitat or any endangered species? Factors considered include:</p> <ul style="list-style-type: none"> • the benefit to the public from the proposal will not outweigh the loss to the public from the destruction or imperilment of the habitat or species; • all feasible and reasonable means of preventing or lessening the impact to the habitat or species have not been or will not continue to be applied, or; • a reasonably acceptable alternative site is owned or controlled by the applicant which would allow the development or subdivision to fulfill its intended purpose.
<p>9. Development affecting public investments</p>	<p>Will the proposal be located adjacent to publicly owned lands or facilities? A permit will be granted for the development or subdivision of lands adjacent to governmental and public utility facilities, services, and lands, when it is demonstrated that the development will not unnecessarily or unreasonably endanger the public or quasi-public investment in the facility, service, or lands, or materially jeopardize or interfere with the function, efficiency, or safety of, or the public's use or enjoyment of or access to the facility, service, or lands.</p>
<p>248(b)(6) Consistency with Approved Integrated Resource Plan (IRP)</p>	<p>Does the proposal reflect the goals and objectives of the approved IRP? Each utility is required to develop and obtain approval for a plan that outlines a strategy for meeting supply and demand objectives. The proposal must be consistent with the principles for resource selection, purchases, investments, or construction as outlined in the IRP. The specifics of each utility's IRP differ and need to be considered individually in the context of the proposal.</p>
<p>248(b)(7) Consistency with Electrical Energy Plan</p>	<p>Does the proposal reflect the goals and objectives of Vermont's Electrical Energy Plan? Intended to ensure that individual proposals contribute to statewide strategies for energy or that there exists good cause to permit the proposed action. The Electric Energy Plan was developed in 2005 and addresses energy resources over a 20 year planning horizon. The plan is available at http://publicservice.vermont.gov/pub/state-plans-electric.html .</p>

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<p>248(b)(8) Outstanding Resource Waters</p>	<p>Will the project affect or be located on a waterbody designated as an “Outstanding Resource Water”? Special protection is provided to water resources that are considered exceptional with respect to recreational, cultural, scenic and/or natural values. There are currently four river reaches with this designation in Vermont, including:</p> <ul style="list-style-type: none"> a) Batten Kill River (East Dorset / Arlington) b) Pikes Falls / Ball Mountain (Jamaica) c) Poultney River (Poultney / Fair Haven) d) Great Falls / Ompompanoosuc River (Thetford) <p>Additional information is available at http://www.nrb.state.vt.us/wrp/orw.htm .</p>
<p>248(b)(9) Solid Waste Management</p>	<p>Does the proposal include a solid waste management plan? Considered with respect to a waste to energy facility proposals. Solid waste management plans must demonstrate consistency with the state solid waste management plan.</p>
<p>248(b)(10) Existing Transmission Facilities</p>	<p>Can the proposal be served economically by existing or planned transmission facilities without undue adverse effect on Vermont utilities or customers? Proposals that require new or significant modification to existing or planned transmission facilities must include these factors in the overall economic and technical feasibility of the project.</p>
<p>248(e) Nuclear Facilities</p>	<p>Does the proposal involve the construction of a nuclear energy generating plant? In addition to meeting the requirements of Section 248 relating to the issuance of a CPG the PSB must obtain approval from the general assembly for the proposal. The proposal must demonstrate that it will promote the general welfare of the citizens of the state.</p>

**Evaluation
Criteria**

Regulatory Test

**Air Pollution
Control**

**Construction (or
Modification) Permit**

Construction permits are required before an electrical generation project can be installed, constructed or modified. There are essentially two distinguishing categories – major sources and minor sources. Major and minor sources are defined in terms of annual quantities of emissions.

**1. Allowable
Emissions /
Major and
Minor Source
Designations**

Will the proposal result in emissions exceedances above the allowable thresholds?
Allowable ton per year (tpy) emission rates are:

- CO ≥ 50
- NO_x ≥ 40
- SO₂ ≥ 40
- PM ≥ 25
- PM₁₀ ≥ 15
- VOC ≥ 40
- Pb ≥ 0.6

Projects which exceed the allowable limits are considered major sources or modifications, emission rates below allowable standards are considered minor projects. Criteria for additional contaminants are provided at <http://www.anr.state.vt.us/air/Permitting/docs/apcregs.pdf>.

**2. Modification
Definition**

Will the proposal result in any physical change in, or change in the method of operation of an existing stationary source which increases the actual emission rate of any air contaminant?

Physical changes or changes in the method of operation do not include:

- Routine maintenance, repair and replacement; or
- An increase in the hours of operation or in the production rate, unless prohibited under any condition of a valid permit.

**3. Most Stringent
Emission Rate
(MSER)**

MSER are defined on a case-by-case basis, determines is achievable for a source based on the lowest emission rate achieved in practice by such category of source, unless the source demonstrates it cannot achieve such a rate due to economic impacts and costs.

If the imposition of an emission standard is determined to be infeasible other measures may be required including:

- Design standard,
- Equipment standards,
- Work practice or operational standard, or
- Combination of the above

Clean Air Act

Operating Permit

Required for any air contaminant source with a maximum allowable emissions of all contaminants of >10 tpy. The requirements of the operating permit differ depending on the emission characteristics of the proposed source. Operating permits incorporate all applicable air pollution control requirements into one document that is renewed every five years.

Clean Air Act

1. Insignificant Activity

Does the proposal qualify as an insignificant activity?
Insignificant activities are generally associated with infrequent or temporary sources of emissions (e.g., emergency generators, fugitive dust from construction activities, etc.). Thermal generation projects are not likely to qualify as an insignificant activity. Insignificant activities are defined in Subchapter X, Section 5-1002 (pages 108-109) at <http://www.anr.state.vt.us/air/docs/apcregs.pdf>.

2. Subchapter X Major Source

Does the proposal qualify as a major source under subchapter X of the Vermont Air Regulations?
Sources are subject to subchapter X requirements if they meet any of the following criteria:

- Release >10 tpy of all contaminants (in aggregate);
- Includes sources subject to federal New Source Performance Standards (NSPS) ; - additional information on NSPS is available at <http://www.epa.gov/nsr/>.
- Includes sources subject to National Emission Standards for Hazardous Air Pollutants (NESHAP), or;
- Includes sources subject to VT Section 5-261 Hazardous Air Contaminant regulations.

Subchapter X sources are required to use Reasonable Available Control Technologies (RACT) to limit the emissions of air contaminants. RACT are devices, systems, process modifications, or other apparatus or techniques designed to prevent or control emissions that are reasonably available, taking into account the social, environmental and economic impact of such controls, and alternative means of emission control.

Additional information on subchapter X of the Vermont Air Regulations is available at <http://www.anr.state.vt.us/air/permitting/htm/OperatePermits.htm>.

3. Title V Source

Does the proposal qualify as a title V source under the Clean Air Act?
Sources are subject to the requirements of Title V of the Clean Air Act if:

- Allowable NO_x, SO₂, CO, or particulate matter emissions are >100 tpy;
- VOC emissions are > 50 tpy;
- NSPS applies;
- NEHSP applies;
- Allowable individual Hazardous Air Pollutant (HAP) emissions are > 10 tpy, or >25 tpy total emissions of HAP.

Additional information on Title V of the Clean Air Act is available at <http://www.epa.gov/air/oaqps/permits/>.

**Evaluation
Criteria**

Regulatory Test

Clean Water Act

**Section 401 – Water
Pollution Prevention
and Control (Water
Quality Certificate)**

Will the proposal impact a waterbody that has received a water quality classification by the State?
Activities requiring water quality certification include the placement of fill in a wetland, licensing of hydro-electric facilities, construction of a retaining wall along a lake shore, and constructing a bridge across a stream. Waterbodies are managed in order to obtain and maintain the current water quality classification. Water quality classifications are available at <http://www.nrb.state.vt.us/wrp/publications/wqs.pdf>. Federal permits and licenses cannot be granted until certification has been issued or waived by the state.

Does the proposal meet the current water quality standards?
The Standards state “determinations of what constitutes an existing use on a particular water body shall be made on a case-by-case basis.”
Water quality certification determinations are based on:

- The proposed activity would not have a significant impact on existing water use by aquatic biota, fish, or wildlife.
- The proposed activity would not have a significant impact on recreation in or on the water, fishing, water supply or commercial enterprises that depend directly on the preservation of any existing level of water quality.

**Section 402 - National
Pollution Discharge
Elimination Systems
(NPDES)**

As authorized by the Clean Water Act, the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating both point and non-point sources with the potential to discharge pollutants into waters of the United States. The NPDES program is administered by the VT ANR.

**1. General or
Individual Permit**

An *individual permit* is a permit specifically tailored to an individual facility based on the type of activity, nature of discharge, receiving water quality.

A *general permit* covers multiple facilities within a specific category. General permits may offer a cost-effective option for permitting agencies because of the large number of facilities that can be covered under a single permit. General permits may be written to cover categories of point sources having common elements, such as:

- Storm water discharges;
- Facilities that involve the same or substantially similar types of operations;
- Facilities that discharge the same types of wastes or engage in the same types of sludge use or disposal practices;
- Facilities that require the same effluent limits, operating conditions, or standards for sewage sludge use or disposal; and

Facilities that require the same or similar monitoring

The type of permit required is determined based on the specifics of the proposal (e.g., footprint of development); additional information on these thresholds is available at http://www.vtwaterquality.org/stormwater/docs/sw_stormwater_101_9-25-06.pdf.

2. Section 316(a)

Will the proposal result in the thermal discharge to waters of the U.S. resulting in a temperature related variance in the water quality standard?

Vermont water temperature standards are determined based on the overall water quality classification. Water quality classifications are

Evaluation Criteria

Regulatory Test

Clean Water Act

available at <http://www.nrb.state.vt.us/wrp/publications/wqs.pdf>.

Variations from state water quality temperature standards are allowed if the variance will "... assure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in and on the body of water into which the discharge is to be made."

3. Section 316(b)

Will the proposal withdraw more than two million gallons per day (MGD) from waters of the U.S.?

OR

Use 25% or more of their intake water for cooling?

New facilities with smaller cooling water intakes will still be regulated on a site-by-site basis.

Section 316(b) provides that any point source shall require that the location, design, construction, and capacity of the cooling water intake structures (CWIS) reflect the best technology available for minimizing adverse environmental impact. This regulation is unique in that it applies to the intake of water and not the discharge. A major goal of this regulation is to minimize the impingement and entrainment of fish and other aquatic organisms as they are drawn into a facility's cooling water intake. <http://www.epa.gov/waterscience/316b/>.

Section 404 – Dredge and Fill Permits

Will the proposal dredge or discharge fill material into the waters of the United States?

And/Or

Will the proposal involve work and structures that are located in or over any navigable water of the United States, the excavating from or depositing of material in such waters, or the accomplishment of any other work affecting the course, location, condition, or capacity of such waters?

Is the project eligible for inclusion under the Vermont General Permit (GP)?

The New England Division of the U.S. Army Corps of Engineers (Corps) issued a General Permit (GP) that expedites review of minimal environmental impact work associated with the aquatic environment of navigable and inland waters and wetlands within the State of Vermont. The GP provides general permit conditions for a variety of project categories. The GP distinguishes projects according to three categories which reflect the potential level of impact to jurisdictional resources. The Categories are:

- *Category I – Non reporting:* may proceed without application or notification to the Corps provided the required Federal, State, and local authorizations are obtained
- *Category II – Reporting / Screening:* require written approval from the Corps. These projects will be reviewed through interagency screening to determine whether such activities may be authorized under the GP
- *Category III – Individual Permit:* work that is not covered by either Category I or II definitions.

The GP establishes impact thresholds for three permitting categories based on the type of project and components of the proposal. In general the project type and thresholds limits are:

1. New Fill / Excavation -
 - a) <3,000 sq ft. = Category I
 - b) >3,000 sq. ft. – 1 acre = Category II
 - c) 1+ acres = Individual Permit
2. Bank Stabilization –
 - a) <100 linear feet and 1 CY of fill below Ordinary High Water (OHW)= Category I
 - b) >100 linear feet and/or >1 CY of fill below OHW = Category II

Evaluation Criteria

Regulatory Test

Clean Water Act

3. River, Stream, Brook Work & Crossings and Waterway and Wetland Crossings–
 - a) Design conforms to GP performance standards and VT ANR WQC Category I qualifications = Category I
 - b) Impacts greater than Category I and proactive restoration projects = Category II
4. Repair, Replacement, In-Kind Maintenance –
 - c) Repair, maintenance of existing authorized serviceable fills with no expansion= Category I
 - d) Repair, maintenance of existing authorized serviceable or non-serviceable fills with <1 acre expansion or change in use or = Category II
 - e) Repair, maintenance of existing authorized serviceable or non-serviceable fills with >1 acre expansion =Individual Permit
5. Miscellaneous –
 - a) Oil spill clean ups, monitoring wells, temporary scientific measurement devices = Category I
 - b) Fishery habitat enhancement projects (including nuisance species management and control projects) and utility line crossings, water intakes and outfalls, dredging up to 5,000 CY with upland disposal or beach nourishment, utility lines installed by directional bores in navigable waters, aerial transmission lines over navigable waters = Category II
 - c) Projects that trigger EIS, any project that affects a special aquatic site, dredging of over 5,000 CY from navigable waters, dredging of any volume from navigable waters with open water disposal.

Each of the project types and categorical definitions have special conditions and exclusions. Special categories and thresholds have been developed for Lake Champlain, Lake Memphremagog, and Wallace Pond. Additional information is available at <http://www.nae.usace.army.mil/reg/vtppg.pdf>.

Projects on the Connecticut River will also need to consider potential impacts to the Atlantic Salmon fishery which is a designated Essential Fish Habitat (EFH) and regulated under the Magnuson-Stevens Fishery Conservation and Management Act. Additional information on the Atlantic Salmon EFH on the Connecticut River in Vermont is available at <http://www.nefmc.org/habitat/index.html>.

**Regulatory
Approval**

Regulatory Test

Vermont Wetland Rules

Wetland Type

Will the proposal include work within a significant (Class I or II) wetland?
The Vermont Wetland Rules (Rules) define three types or classes of wetlands based on ten evaluation criteria which characterize the relative significance of the resource function. Additional information on wetland functions and values is available at http://www.anr.state.vt.us/dec/waterq/wetlands/htm/wl_function.htm.
Wetlands are afforded different levels of protection depending on their defined class. Wetland classifications and associated level of regulatory protection are:

- *Class I* – determined to be exceptional or irreplaceable in their contribution to Vermont’s natural heritage. Class I wetlands include an upland buffer zone 100 feet wide measured from the delineated edge of the wetland.
- *Class II* - the Rules designate most palustrine wetlands shown on the National Wetland Inventory (NWI) maps and those wetlands contiguous to mapped wetlands as class II wetlands. Class II wetlands include an upland buffer zone 50 feet wide measured from the delineated edge of the wetland.
- *Class III* - considered not significant for providing any wetland functions when last evaluated or that have not been mapped on the NWI maps. Class III wetlands are not protected under the Rules; they may, however, be protected by other federal, state, or local regulations.

The location and extent of class I and II wetlands are mapped under the Vermont Significant Wetland Inventory (VSWI); additional information is available at http://www.anr.state.vt.us/dec/waterq/wetlands/htm/wl_vermontsigwetinvmaps.htm.

Allowed Uses

Certain activities are allowed within significant wetlands and their adjacent buffer zones without review under the Rules, provided there is no draining, dredging, filling, grading or alteration of the water flow into or out of the wetland. Examples of allowed use categories include:

- Recreation
- Routine repair and maintenance;
- Pond maintenance;
- Docks and fences;
- Residential related activities;
- Logging;
- Farming;
- Nuisance plant control, and;
- Other (operation of existing hydroelectric facilities, scientific research, wildlife and fisheries management, etc.)

Each of the categories has specific requirements that must be met in order to qualify as an “allowed” activity. A complete listing of allowed uses and guidance for qualification is available at: http://www.anr.state.vt.us/dec/waterq/wetlands/docs/wl_factsheet6.pdf.

Conditional Uses

Proposals which include activities within class I or II wetlands or their associated buffers, that are not identified as “allowed” (see above) are considered conditional uses and require application to the VT ANR for a Conditional Use Determination (CUD). A CUD may only be granted when it is shown that the proposal use will not effects on the significant functions of the wetland.

**Regulatory
Approval**

Regulatory Test

Vermont Stormwater Rules	DEC Stormwater Program	The Vermont Department of Environmental Conservation Stormwater Program issues separate permits for runoff from impervious (i.e. hard) surfaces, construction sites and industrial facilities. All new projects, redevelopment projects and expansion projects should be evaluated to determine whether a State Stormwater Permit <u>and/or</u> a Construction Stormwater Permit is needed in order to comply with 10 V.S.A 1264 and the federal Clean Water Act, respectively. If these facilities are industrial in nature or if you have an existing industrial facility, such facilities may also have to seek coverage under the Multi-Sector General Permit (MSGP). Many projects will require both the State Stormwater and Construction Stormwater Permit; some projects may require all three permits.
	1. State Stormwater Permit	The State Stormwater Discharge Permit program has specific jurisdictional thresholds based on the amount of impervious surface. The DEC has a worksheet to determine project eligibility which is available at http://www.vtwaterquality.org/stormwater/docs/sw_jurisdiction_9-25-06.pdf .
	2. Construction Stormwater Permit	Will the proposal involve the disturbance of >1 acre of land? The project may require a permit to manage stormwater during construction activities. Additional information related to determining if a specific proposal is under the jurisdiction of this permit program is available at http://www.vtwaterquality.org/stormwater/docs/sw_jurisdiction_9-25-06.pdf .
	3. Multi-Sector General Permit (MSGP)	The Multi-Sector General Permit (MSGP) Program addresses stormwater runoff associated with industrial facilities. A facility must seek coverage under the MSGP if the Standard Industrial Classification (SIC) code that describes the facility identified in the general permit which include steam generation facilities. The permit requires facilities to examine potential sources of pollution, implement measures to reduce the risk of stormwater contamination, and test stormwater discharges for sources of pollution. Additional information on the MSGP is available at http://www.vtwaterquality.org/stormwater/htm/sw_msgp.htm .

**Evaluation
Criteria**

Regulatory Test

Federal and State Endangered Species Laws

Federal Endangered Species Act (ESA) - Section 7

Will the proposal impact federally listed species or designated critical habitats?
A request to review the proposed project with potential listed species and critical habitat conflicts is submitted to the U.S. Fish and Wildlife Service (FWS) regional office (<http://www.fws.gov/northeast/endangered/>). FWS reviews the proposal with respect to known occurrences of protected species and habitats and makes a determination of potential project impacts. Possible decisions include:

- No impact – no further consultation required
- Potential impact – avoidance strategies are developed and agreed to by FWS and proponent
- Impact/ Take required – Incidental Take Permit is required. To obtain a permit, the applicant must develop a *Habitat Conservation Plan* (HCP), designed to offset any harmful effects the proposed activity might have on the species. The HCP process allows development to proceed while promoting listed species conservation.

What is the listing designation and associated level of legal protection?
The ESA defines several categories of species listing that differentiate the relative rarity and susceptibility of particular species. Designations under the federal ESA include:

- LE = Listed Endangered
- LT = Listed Threatened
- PDL = Proposed for Delisting
- C = Candidate for Listing (not legally protected)
- SC = Species of Concern (not legally protected)

Additional information on listed species and habitats is available at <http://www.fws.gov/endangered/>.

Vermont Non-game and Natural Heritage Program (NNHP)

Will the proposal impact any State listed species?
The Vermont NNHP maintains a current inventory of state listed species. Additional information on VT listed species and the NNHP is available at http://www.vtfishandwildlife.com/wildlife_nongame.cfm.

What is the listing status and associated level of legal protection for potentially affected species and/or communities?
The VT Endangered Species Law defines several categories that differentiate the relative rarity and susceptibility of particular species. The level of legal protection is directly related to the listing status. Designations under the Vermont Endangered Species Law include:

- E = Endangered: in immediate danger of becoming extirpated in the state
- T = Threatened: with high possibility of becoming endangered in the near future
- PDL = Proposed for Delisting
- PE = Proposed for Endangered Status (not legally protected)
- PT = Proposed for Threatened Status (not legally protected)
- SC = Special Concern: status should be watched (not legally protected)

**Evaluation
Criteria**

Regulatory Test

Federal Power Act

**Federal Energy
Regulatory
Commission - FERC**

The Federal Energy Regulatory Commission, or FERC, is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects.

1. Hydropower

FERC issues licenses for the construction of a new project; the continuance of an existing project (relicensing); and oversight of all ongoing project operations, including dam safety inspections and environmental monitoring. There are several licensing options available depending on the size and nature of the proposal. Licensing options include:

- Traditional Licensing Process(TLP) – three stage consultation process
- Integrated Licensing Process (ILP) – intended to provide expedited processing through combination of consultation and application procedures.
- Alternative Licensing Process (ALP) - combines several process elements with applicant prepared NEPA environmental review.
- Licensing Exemption – utilizes the TLP and provides operating licenses in perpetuity. There are two types of exemptions with specific eligibility requirements:
 - Small hydro – 5 megawatts or less, that will be built at an existing dam, or projects that utilize a natural water feature for head or an existing project that has a capacity of 5 megawatts or less and proposes to increase capacity.
 - Conduit - generating capacities 15 megawatts or less for non-municipal and 40 megawatts or less for a municipal project. The conduit has to have been constructed primarily for purposes other than power production and be located entirely on non-federal lands.

Additional information on the FERC licensing options and processes is available at <http://www.ferc.gov/industries/hydropower/gen-info/licensing.asp>.

2. Electrical

The FERC is responsible for:

- Approval of rates for wholesale sales of electricity and transmission in interstate commerce for jurisdictional utilities, power marketers, power pools, power exchanges and independent system operators;
- Oversight of the issuance of certain stock and debt securities, assumption of obligations and liabilities, and mergers;
- Review of officer and director positions held between top officials at utility companies and certain firms with which they do business;
- Review of rates set by the federal power marketing administrations;
- Review of exempt wholesale generator status, and;
- Certification of qualifying small power production and cogeneration facilities.

Additional information on FERC regulation of the electrical reliability, OATT, and transmission line siting is available at <http://www.ferc.gov/industries/electric.asp>.

Federal Power Act

3. Oil	<p>FERC jurisdiction on oil industry activities is related to:</p> <ul style="list-style-type: none"> • Regulation of rates and practices of oil pipeline companies engaged in interstate transportation; • Establishment of equal service conditions to provide shippers with equal access to pipeline transportation; and • Establishment of reasonable rates for transporting petroleum and petroleum products by pipeline. <p>Additional information on FERC regulation of the oil industry is available at http://www.ferc.gov/industries/oil.asp.</p>
4. Gas	<p>FERC regulates pipeline, storage, and liquefied natural gas facility construction, including:</p> <ul style="list-style-type: none"> • Regulation of natural gas transportation in interstate commerce; • Issuance of certificates of public convenience and necessity to prospective companies providing energy services or constructing and operating interstate pipelines and storage facilities; • Regulation of facility abandonment; • Establishment of rates for services; • Regulation of the transportation of natural gas as authorized by the NGPA (Natural Gas Policy Act) and the OCSLA (Outer Continental Shelf Lands Act), and; • Oversight of the construction and operation of pipeline facilities at U.S. points of entry for the import or export of natural gas. <p>Additional information on FERC regulation of the gas industry is available at http://www.ferc.gov/industries/gas.asp.</p>
Independent Service Operators-New England (ISO-NE)	<p>Will the proposal require new or modified interconnection? Interconnection to the NEPOOL market is administered by the ISO-NE. Application requirements vary depending on the capacity of the proposal, categories include:</p> <ul style="list-style-type: none"> • Small Generator (<20 MW) • Large Generator (>20 MW) <p>Proposals for interconnection may require system studies to determine if the proposed new generation can be support reliability standards. Additional information on ISO-NE regulation of new generation interconnection is available at http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/index.html.</p>

Evaluation Criteria

Regulatory Test

Federal Land Protection Mgt. Act	Forest Service Special Use Permit	<p>The U.S. Forest Service (NFS) administers a special-uses program to review and authorize uses on NFS land that provide a benefit to the general public and protect public and natural resources values.</p>
		<p>Does the proposal include use of the Green Mountain National Forest? The Green Mountain National Forest includes almost 400,000 acres that stretch across nearly two-thirds the length of Vermont. Additional information is available at http://www.fs.fed.us/r9/gmfl/green_mountain/index.htm.</p> <p>A special use permit is required if the proposal will:</p> <ul style="list-style-type: none"> • Occupy, use, or build on National Forest Service (NFS) land for personal or business purposes; • Include a fee charge or result in the generation of income from the use, or; • Involve individuals or organization with 75 or more participants or spectators. <p>Permit application forms are available at http://www.fs.fed.us/recreation/permits.</p>
		<p>The Forest Service has a pending directive addressing proposals including Forest Service lands for wind energy development. The proposed directives address proposals and applications for and issuance of two types of wind energy permits:</p> <ul style="list-style-type: none"> • Site testing and feasibility permits for the collection of data on the wind resource, and • Permits for construction and operation of a wind energy facility. <p>Additional information is available at http://www.fs.fed.us/recreation/permits/documents/federal_register_wind.pdf.</p>

Evaluation Criteria

Regulatory Test

Nuclear Regulatory Commission

Two-Step Licensing Process (10 CFR Part 50)

All nuclear power plant applications must undergo a safety review, an environmental review and antitrust review by the NRC. Additional information is available at <http://www.nrc.gov/reactors/new-licensing/licensing-process.html>.

1. Construction Permit

Proposals that include the construction of new nuclear energy generation facilities must apply for and obtain a Class 103 (commercial and industrial facilities). All nuclear power plant applications must undergo a safety review, an environmental review and antitrust review by the NRC. Evaluation criteria include:

- Plant design;
- Safety review, and;
- Environmental review - includes National Environmental Policy Act (NEPA) review.

Additional information on construction (new reactor) licensing is available at <http://www.nrc.gov/reactors/new-licensing/licensing-process.html>.

2. Operating Permit

Operating permits are required for new and existing nuclear generation projects.

- *New Projects* - after the initial license is granted, the license may be amended, renewed, transferred, or otherwise modified, depending on activities that affect the reactor during its operating life.
- *Existing Projects* - The license renewal process and application requirements for commercial power reactors are based on two key principles:
 - The regulatory process, continued into the extended period of operation, is adequate to ensure that the current licensing basis of all currently operating plants provides an acceptable level of safety, with the possible exception of the detrimental effects of aging on certain systems, structures, and components, and possibly a few other issues related to safety only during the period of extended operation, and;
 - Each plant's current licensing basis is required to be maintained during the renewal term.

Additional information on operating license renewals is available at <http://www.nrc.gov/reactors/operating/licensing/renewal.html>.

Combined Licensing Process (10 CFR Part 52)

In an effort to improve regulatory efficiency and add greater predictability to the process, in 1989 the NRC established alternative licensing processes in 10 CFR Part 52 that included a combined license. This process, although not used to date, combines a construction permit and an operating license with conditions for plant operation.

1. Combined Construction/Operation (COL) License

A combined license authorizes construction of the facility in a manner similar to a construction permit under the two-step process. It must contain essentially the same information required in an application for an operating license issued under 10 CFR Part 50 and specify the inspections, tests, and analyses that the applicant must perform. It also specifies acceptance criteria that are necessary to provide reasonable assurance that the facility has been constructed and will be operated in conformity with the license and applicable

	regulations. If an early site permit and design certification are not referenced, then the NRC reviews the technical and environmental information as described for the two-step licensing process. Additional information on the combined license is available at http://www.nrc.gov/reactors/new-licensing/col-appl-guide.html .
2. Early Site Permit	An early site permit resolves site safety, environmental protection, and emergency preparedness issues independent of a specific nuclear plant design. The early site permit application must address the safety and environmental characteristics of the site and evaluate potential physical impediments to developing an acceptable emergency plan. Additional information on early site permits is available at http://www.nrc.gov/reactors/new-licensing/esp.html .
3. Certified Standard Plant Designs	The NRC may approve and certify a standard nuclear plant design through a rulemaking, independent of a specific site. The design certification is valid for 15 years. An application for a standard design certification must contain proposed inspections, tests, analyses, and acceptance criteria (ITAAC) for the standard design. Additional information on certified plant designs, including issued certified designs, is available at http://www.nrc.gov/reactors/new-licensing/design-cert.html .

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