Climate Neutral Campus Energy Alternatives Report

Appendix B: Additional Technical Information

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Overview and Purpose

This appendix contains content from an internal study completed in 2015 that evaluated various options for provided renewable heat for campus. Although some options also provided at least some portion of the campus electric capacity, the intent of the report was more limited that the scope of the 2016 Climate Neutral Campus Energy Alternatives Report (CNCEAR).

The purpose of including this prior work is to provide additional details resulting from research into some of the key low-carbon/no-carbon alternatives investigated. As such, this should be considered as additional/supplemental information only.

Some information from the 2015 report (and included in this appendix) has been superseded or is no longer valid, and the scope of the two studies differed. Specifically, readers should note the following:

- The cost information contained herein has been re-evaluated, and many costs updated to the final estimates included in the body of the CNCEAR. For example, some of the costs included in this Appendix do not include “soft costs” or other costs that were added later in an attempt to have similar cost bases for all options. The final costs and bases are documented in the CNCEAR.

- The qualitative (“quadruple bottom line”, or QBL) evaluations contained in this Appendix, while informative, were conducted by internal Facilities Engineering staff with input by a limited number of IPP professionals only, and were not informed by the SLCAG or any other broader stakeholder group. The QBL rankings by SLCAG are included in the CNCEAR and should be used for guidance by campus leaders.

- The scale of some actions were revised for the CNCEAR report as noted in that report. For example, the CNCEAR report describes a B/ESH options whereby 3% of the heat load would be provided by biomass, while the example described in this Appendix uses biomass for 9% of the heat load (resulting in a much higher biomass demand and associated impacts, but lower ESH cost than the CNCEAR basis). If the B/ESH option were pursued, the final sizing of both systems would be based on an optimization study after pilot (test well and small biomass plant) testing.

- Some of the options reviewed in the earlier study are no longer considered viable and as such have been eliminated from this Appendix.

- This Appendix does not review WWS resources for renewable electricity in any detail; those resources are discussed in the CNCEAR report only.

Despite these significant differences, this Appendix does provide further details on many of the technologies investigated which may be of value to reviewers of the CNCEAR.

1 Biomass/biogas combustion

Background

The principle behind the use of biomass energy to reduce carbon emissions is that, if harvested sustainably, biomass crops absorb as much carbon each year as is released during combustion. However, it is important to minimize additional energy inputs related to production, harvesting, transportation, storage, and processing of biomass crops since these activities will likely also have an associated carbon footprint. Here we consider the potential for biomass energy to supply all of Cornell's thermal energy needs under two scenarios: direct combustion, and biogas production and combustion. Direct combustion of biomass in steam boilers would heat campus in a manner similar to our previous coal combustion system; combustion of biogas would occur in gas turbines in a manner similar to the current natural-gas fired CCHPP.

Figure 1.1 illustrates the differences in combustion and gasification processes. Direct combustion technology is well developed and widely proven in a variety of applications. Direct combustion systems deliver heat by direct transfer of hot exhuast gas or by indirect transfer of heat to air or a working fluid such as hot water or steam. Combustion efficiency is a function of the completeness of the combustion process, which in turn is dependent on the amount of oxygen available for the process. The combustion process is controlled by the quantitiy and location of air supplied to the process. Gasification is a thermochemical process with the potential to convert biomass to multiple end products by adjusting the process heating temperature and heating rate. If biomass is heated slowly at temperatures ranging from 200-400 °C, biomass converts to biomass charcoal (biochar, potentially used for carbon dioxide sequestration) with subsequent release of synthetic gas (syngas) which consists mainly of carbon monoxide, carbon dioxide, methane, and hydrogen. If heating rate and temperature are increased up to 800-1100 °C, the essentially all of the biomass largely converts to syngas (with a resulting higher gas generation), which can be used in cogeneration with turbines.

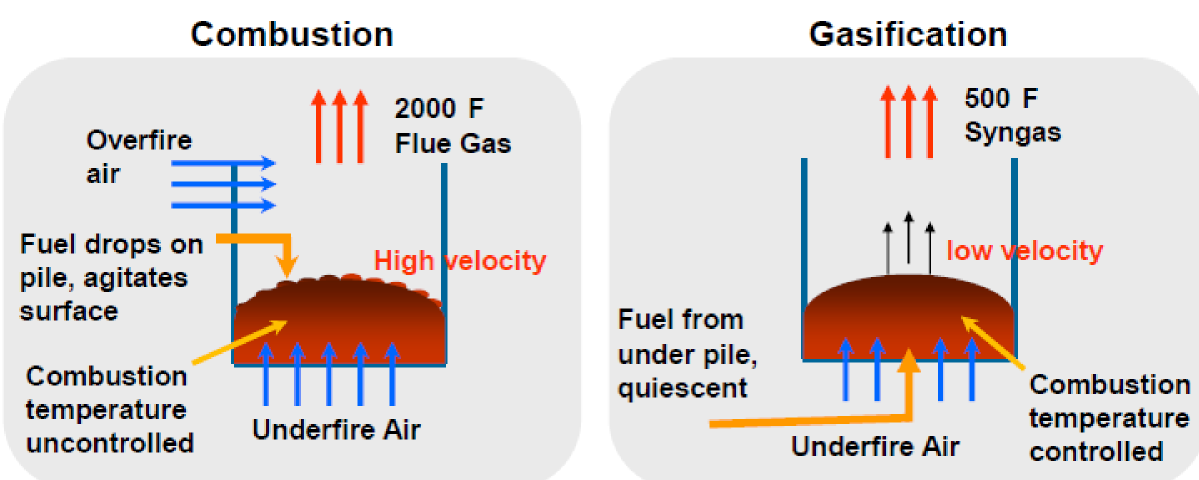

Figure 1.1 Direct combustion of biomass (a) vs gasification conversion of biomass (b) [ORNL, 2012].

Cornell's 2009 CAP proposed an action to co-fire 10% wood along with the coal in the two main boilers that were in use at the time, as an incremental step in reducing fossil fuel use. Since then the CEP has converted to natural gas cogeneration. In subsequent updates to the CAP, the assessment of potential biomass energy has focused on use of campus waste streams and other university owned biomass resources to generate renewable energy through CURBI (the Cornell University Renewable Bioenergy Initiative).

The CURBI project was developed by a team at the Cornell University Agricultural Experiment Station with the goal of reducing campus GHG emissions and identifying beneficial uses for approximately 30,000 tons per year of biomass produced within Cornell University [CURBI, 2010]. University generated biomass considered included food waste from the dining halls, manure and bedding from various animal research operations, crop wastes, woody biomass from University owned forests, and renewable energy crops. Five bioenergy processes were evaluated for inclusion in the CURBI facility: Direct combustion, anaerobic digestion, dry fermentation, pyrolysis/torrefication, and biodiesel conversion. CURBI identified direct combustion, anaerobic digestion, and biodiesel conversion as options that could be implemented with a high probability for successful operation due to previous experience on hundreds of similar projects. Although it was judged to be a less mature technology, gasification has the advantage of being able to utilize multiple types of campus waste and feedstock from wood-based organics such as sawdust, bedding, forest products, and agronomic crop to non-woody organics such as food waste, hydrolysate, manure, and other agronomic crop feedstock.

To minimize energy needed for transportation, CURBI considered available biomass generated on Cornell lands within a 25 mi radius of campus. A summary of feedstock available from Cornell owned lands is shown below in Table 1.1. Given these production rates and energy content values, Cornell produces a potential energy source of nearly 300,000 MMBTU/year from University owned land and facilities [CURBI, 2010].

Highlight Box 1: Biomass available on Cornell owned lands

Updated numbers from Cornell researchers David Weinstein and Larry Smart provide that 2000 acres are available to convert from fallow agricultural land to biocrop land. Willow has a 45% moisture content whereas forest residue has ~35%. Recent work indicates that current yield of willow is ~6 dry tons/acre and .75 dry tons/acre of well managed forest. Switchgrass produces similar yield and energy content to willow; however, it may not be good operationally due to high ash content and high chloride.

Table 1.1: Summary of available biomass feedstock available on Cornell University land for biomas-to-energy projects [CURBI Report, 2010].

SOURCE	FEEDSTOCK COMPONENT	TONS/YR (COLLECTED)	MOISTURE (%)	TONS/YR (DRY MATTER)	SEASONALITY	OBSTACLES
Crops	Dedicated energy crops baled (4x4x8 bales)	8,000	15	6,800	Bales (1,500 lbs)	Dust and debris from debaling
Veterinary Hospital	Animal manure and bedding	2,886	30	2,020	Constant - 2 to 6 tons/day	Odors
Forests	Culled forestry cuttings	1,250	34	825	Constant - grind and stockpile	
Forests	Woody biomass	6,000	40	3,600	Constant - grind and stockpile	
Animal Science	Animal manure and bedding	116	40	70	Cleaned periodically- sawdust and manure	Odors
Polo fields	Horse manure and sawdust	2,189	40	1,313	45 tons/week 50% moisture. Cleaned twice per week, 15 tons/week in summer	Odors
Various	Pre-ground pallet waste	1,350	47	715	Constant - grind and stockpile	
Poultry buildings	Chicken manure and kraft paper	60	50	30	One to two cleanings/week	Odors
Greenhouses	Plant material and soil	274	70	82	Constant - stockpile	Soil in feedstock
Plant science	Plant material and soil	320	70	96	Growing season; grind for dry fermentation, April-October	Soil in feedstock
Plantations	Plant material	36	70	11	Growing season - grind for dry fermentation. April – October	
Dining halls	Food waste	458	90	141	Spring and Fall semesters – 5 to 6 tons day; Summer session - July-August 1 ton/day	Inorganic, plastic contaminants. Must blend with drier feedstock
Animal science	Large animal manure	208	90	64	Highly variable day to day depending on research; estimated 4 tons/week average	Odors
CCVM Dairy Complex	Animal manure and bedding	5,000	90	500	Constant	Odors

Table 1.1 (continued): Summary of available biomass feedstock available on Cornell University land for biomas-to-energy projects [CURBI Report, 2010].

SOURCE	FEEDSTOCK COMPONENT	TONS/YR (COLLECTED)	MOISTURE (%)	TONS/YR (DRY MATTER)	SEASONALITY	OBSTACLES
Swine Research Farm	Swine manure	480	95	24	Constant	Odors, mixing problems
Veterinary School	Alkaline hydrolysate	1,800	100	N/A	Variable batches of 3,000 gallons each	Odors, hydrolysate storage tanks - septic
Dining halls	Waste vegetable oil	23	N/A	N/A	Drops off in January, May/June 6,000 gallons	Mixing problems
		30,450		**16,291**		

Biomass combuster operated year round to supply heat to feedstock dryer.
Wood-fired boiler efficiency assumed to be 85 percent.
Recoverable energy values from U.S. Forest Service General Technical Report 29 (1979); adjusts for moisture during combustion.

Thermal resource

Since biomass has a relatively low energy density compared to fossil fuels, biomass energy requires a significant volume of fuel. This poses challenges in terms of the land area required to produce the feedstock, the resources required to harvest, transport, and process the fuel, and the logistics of the combustion process itself. These issues reduce the value of biomass as a thermal resource. Grass crops, such as switch-grass, would require different handling, storage, and combustion infrastructure. Grasses would be field-dried and baled in large bales; these would be loaded by forklift onto flatbed trucks for transport to the storage barns, where they would be stacked several bales high. As with willow chips, storage capacity would be required for the months from the last harvest in the fall until the first harvest in late spring. Bales would be trucked from the storage facility(s) to the heating plant, where they would either be shredded or loaded into a whole-bale combustion boiler. As with wood chips, several days' storage would be required at the heating plant.

Given the different nature of wood chip and grass biomass system optimization, a possible approach would be to utilize wood chips at the central heating plant, and utilize grass bales at smaller, satellite facilities dedicated to heating outlying facilities (e.g. the Guterman greenhouse complex). Alternatively, biomass fuel could be densified offsite into pellets or similar products; this would help homogenize the fuel properties, and could allow for blending of woody and non-woody biomass feedstock. However, densification typically only makes sense (both economically and in terms of resource use) if the fuel must be transported fairly long distances (~25 miles or more). For our analysis of biomass production and heat content, we have assumed that wood chips (willow and/or forest residue) would be utilized.

While both biomass/syngas combustion produce high temperatures and could produce steam, converting to a hot water distribution system would consume ~17% less fuel. Assuming conversion to a more efficient hot water distribution system, ~150,000 wet tons (for direct combustion) to 280,000 wet tons (for gasification) of shrub willow would be needed, requiring ~14,000 to 26,000 acres of cropland. Some of that could be replaced with forest residue as available, with 8 acres of forest residue needed to replace each acre of cultivated willow. Based on comparison with other options, biomass combustion and gasification were rated MEDIUM in this category, as the resource could be sufficient but has significant drawbacks in terms of production and handling of the quantities of fuel required.

For optimizing energy output, woody biomass is primarily considered in the remainder of this analysis. To simplify our study, willow, sustainably cultivated on Cornell lands, was selected as the biomass source. Field tests in Central New York [CURBI, 2010] produced willow with yields between 3.7 and 5.2 dry tons/acre/year (1 ton equals 907kg). For this study, new information on crop yield provided by Larry Smart was assumed to be an average value of 6 dry tons/acre/year [Larry Smart, June 2015]. The maximum amount of idle pasture and crop land available for willow cultivation at Cornell is about 4,000 acres [Cornell University, 2014]. Dry biomass products are regarded as most suitable for thermo-chemical processing technologies since removing moisture from wet wastes consumes energy by the heat of vaporization and thereby reduces the available amount of energy from the process. Also, the relative ash content of the biomass sources affects the efficiency of gasification and is ~0.5% for wood, and 5-10% for agricultural crops. At high temperatures, melted ash becomes sticky and can cause operational problems.

Direct Combustion

Background

Two types of feedstocks could be used for direct combustion: grasses and woody biomass. Woody biomass (forest residues or willow crops) would be chipped at the time of harvest and trucked to covered barns, sheds, or silos on the outskirts of campus for storage. Storage capacity adequate to cover the winter and spring months would be required, from the last willow harvest in the fall until the first harvest of the summer. Assuming that 80% of the yearly amount would need storage, facilities would be required for ~75,000 tons of dried biomass (15% moisture). For scale, assuming a density of 500 lb/cu. yd, this would cover Schoellkopf Field to a depth of ~150 feet. Forest residues from Cornell owned land would be produced year-round, but they are expected to provide only 10% of the fuel needed. Wood chips would then be loaded onto 20-ton truck trailers for delivery to the central heating plant. During peak heating demand in the wintertime, the equivalent to an average of ~3 deliveries per hour would be required. Two or three days' storage would be needed at the heating plant to provide adequate fuel over weekends or during temporary disruptions to transportation (e.g. winter storms). At the heating plant, conveyors would move the fuel from storage hoppers to the boilers. From the boilers on, the system would operate very much like Cornell's previous coal-fired heating plant.

Figure 1.2: Example of how biomass is transported from the field to a storage barn after being chipped and blown into a 15-ton dump trailer.

Figure 1.3: Aerial view of the 39 MWe ReEnergy plant in Ashland, ME

Automated systems would remove ash to silos, from which it would be trucked for beneficial re-use on agricultural land. NYSDEC has determined that unadulterated wood ash has a beneficial use as a soil amendment and does not qualify as solid waste, provided the application rate of the wood ash is limited to the nutrient need of the crop grown on the land on which the wood ash will be applied and does not exceed 16 dry tons per acre per year (see 6 NYCRR Part 360-1.15(b) (13)).

For our analysis of biomass production and heat content, we have assumed that wood chips (willow and/or forest residue) would be utilized [see Highlight Box 1].

Figure 1.4: A typical wood-fired boiler plant layout.

GHG offset potential

The entire amount of GHG emissions from CEP operations (~152,000 tons/year) would be replaced with carbon-neutral biomass under this scenario. However, there would be some GHG emissions associated with biomass crop production, harvesting, transportation, storage, and processing that would need to be accounted for. In addition, heating with direct combustion would result in ~90% lower electricity production; this would increase grid electricity purchases by ~194,000 MWh and associated GHG emissions by ~50,000 tons (using the current grid emission factor). Therefore, the net GHG reduction would be ~103,000 tons. Based on these estimates and comparison with other options, biomass direct combustion was rated MEDIUM in this category, as it could offset ~67% of the CEP GHG emissions.

Technical unknowns

Large-scale biomass combustion plants are in operation at numerous locations across the northeastern US; many of these plants are converted former coal-fired facilities. The boiler technology is commercially available. Since there are no significant technical unknowns, biomass combustion was rated HIGH in this category.

Implementation time

The ReEnergy Black River facility generates ~54 MWe at a converted coal power plant. Conversion of the facility to biomass fuel took about 18 months. Establishing biomass crops and afforestation will take 3-20 years, but stored biomass in forests can supply additional material above the sustainable rate for the first few years. Based on these estimates and comparison with other options, biomass gasification was rated HIGH in this category.

Cost

The initial capital investment for the biomass combustion system is estimated to be $120M (excluding distribution conversion), including ~$100M for boilers and ~$20M for biomass storage/handling/processing facilities. In addition, associated capital costs would include ~$100M for distribution conversion, although this cost is budget-neutral on a LCC basis due to elimination of steam system upgrades and maintenance.

Operating expenses for biomass combustion would be related to the purchase of biomass feedstock, handling of the biomass fuel, and plant maintenance. No current market exists for such large scale biomass locally; sustainable-harvest fuel costs of ~$50/dry ton or ~$7-10/MMBtu have been estimated for the purpose of this study. Based on this assumption, fuel costs would be ~$4M/yr. Feedstock handling and plant maintenance will cost an additional ~$5M/yr.

In addition, electricity currently produced by CCHPP would have to be purchased from the grid. The increased electricity purchases would cost ~$17M/yr (at $0.08/kWh). Total operating expenses are therefore estimated to be ~$26M/yr.

Based on these estimates and comparison with other options (Table 6.2), biomass direct combustion was rated HIGH in this category.

Gasification

Background

Gasification is a form of pyrolysis, a thermo-chemical conversion of biomass to one or more products in the absence of oxygen. Pyrolysis offers a variety of usable end products from biomass, depending on the heating rate and temperature at which the process is operated. With gasification, the main product is syngas, i.e. synthetic gas containing hydrogen, carbon monoxide, methane, and other gases. Figure 1.5 illustrates the gasification process with associated feedstock and byproduct handling in a traditional gasifier. Studies show that off-design operation without retrofitting is possible but a higher performance and durability can be obtained by optimizing certain components such as the turbine cooling system and combustor. Identifying the specific retrofitting requirements for the Cornell system is out of the scope of this study. However, a drop of 20% in CHP conversion efficiency to heat and electricity is considered as penalty for switching from natural gas to syngas [Beckers et al., 2015]. Retrofitting costs are neglected as they are assumed to occur as part of a regular major overhaul investment.

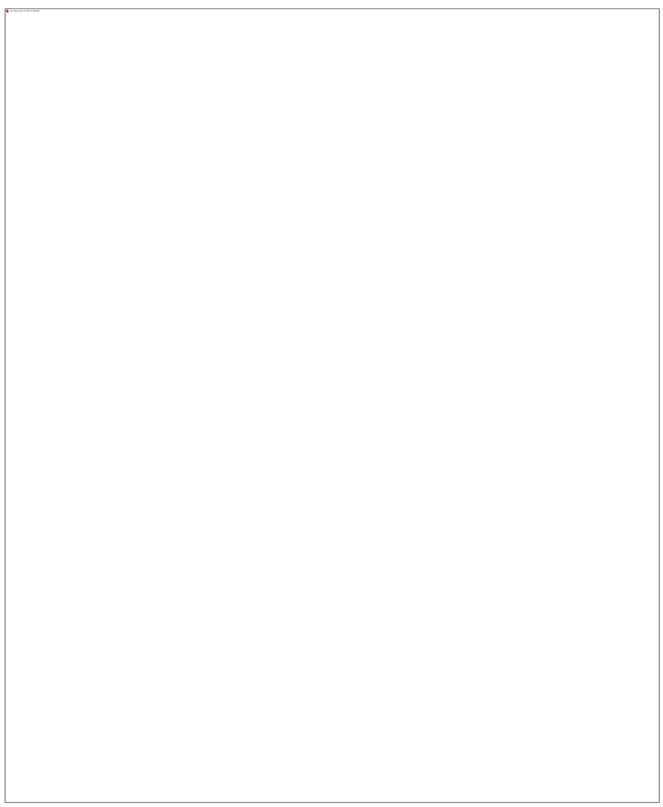

Figure 1.5: Illustration of gasification process

Woody biomass (forest residues or willow crops) would be chipped at the time of harvest and trucked to covered barns, sheds, or silos on the outskirts of campus for storage. Assuming that 80% of the yearly amount would need storage, facilities would be required for ~120,000 dry tons of biomass (15% moisture). Storage capacity adequate to cover the winter and spring months would be required, from the last willow harvest in the fall until the first harvest of the summer. Forest residues from Cornell owned land would be produced year-round, but they are expected to provide only 5% of the fuel needed. Two or three days' storage would be needed at the gasification plant to provide adequate fuel over weekends or during temporary disruptions to transportation (e.g. winter storms). At the gasification plant, conveyors would move the fuel from storage hoppers to the gasifiers (Figure 1.6).

Figure 1.6: Illustration of gasification facility [ORNL. 2011]

From the gas turbines on, the system would operate very much like Cornell's existing CCHP (Combined Heat and Power) plant. Automated systems would remove ash to silos, from which it would be trucked for beneficial re-use on agricultural land. NYSDEC has determined that unadulterated wood ash has a beneficial use as a soil amendment and does not qualify as solid waste, provided the application rate of the wood ash is limited to the nutrient need of the crop grown on the land on which the wood ash will be applied and does not exceed 16 dry tons per acre per year (see 6 NYCRR Part 360-1.15(b) (13)).

For our analysis of biomass production and heat content, we have assumed that wood chips (willow and/or forest residue) would be utilized [see Highlight Box 1].

GHG offset potential

The entire amount of GHG emissions from CEP operations (~152,000 tons/year) would be replaced with carbon-neutral biomass under this scenario. However, there would be some GHG emissions associated with biomass crop production, harvesting, transportation, storage, and processing that would need to be accounted for. The current electric demand for campus is 216,000 MWh; using existing infrastructure, Cornell would be able to co-generate 156,000 MWh electric in addition to our heat demand using gasification. The remaining electric demand would be purchased from the grid (increasing GHG emissions by 39,000 tons). Therefore, the net GHG reduction would be ~137,000 tons. Based on these estimates and comparison with other options, biomass gasification was rated HIGH in this category, as it could offset ~90% of the CEP GHG emissions.

Technical unknowns

Existing gasification plants are typically smaller in scale than what would be required to heat the Cornell campus, but large-scale gasification operations have been demonstrated. Based on comparison with other options, biomass gasification was rated HIGH in this category.

Implementation time

Based on model systems elsewhere in the Northeast region such as at Middlebury and Fort Drum, we would expect at least 2-3 years for planning to installation. Establishing biomass crops and afforestation will take 3-20 years, but stored biomass in forests can supply additional material above the sustainable rate for the first few years. Based on these estimates and comparison with other options, biomass gasification was rated HIGH in this category.

Cost

The initial capital investment for the biomass gasification system is estimated to be $120M (excluding distribution conversion), including ~$72-80M for boilers and ~$20M for biomass storage/handling/processing facilities. In addition, associated capital costs would include ~$100M for distribution conversion, although this cost is budget-neutral on a LCC basis due to elimination of steam system upgrades and maintenance.

Operating expenses for biomass combustion would be related to the purchase of biomass feedstock, handling of the biomass fuel, and plant maintenance. No current market exists for such large scale biomass locally; sustainable-harvest fuel costs of ~$50/dry ton or ~$3/MMBtu have been estimated for the purpose of this study. Based on this assumption, fuel costs would be ~$6M/yr. Feedstock handling and plant maintenance will cost an additional ~$5M/yr.

In addition, a fraction of electricity currently produced by CCHPP would have to be purchased from the grid. The increased electricity purchases would cost ~$5M/yr (at $0.08/kWh). Total operating expenses are therefore estimated to be ~$16M/yr.

Based on these estimates and comparison with other options (Table 6.2), biomass gasification was rated HIGH in this category.

Common to Both Biomass Alternatives

Non-GHG environmental impacts

Besides GHG emission reductions, the replacement of natural gas combustion at the CEP with biomass will prevent the release of nitrogen and sulfur oxides. To the extent that natural gas production is offset, ESH will reduce methane emissions, land disturbance, water use, and drilling/fracking waste associated with natural gas extraction. Utilization of biomass energy could be coupled with good forest management practices to remove less desirable tree species and to promote a diversity of maturity in forested plots, which would promote healthy biodiversity. Biomass crops such as willow and switchgrass could also be beneficial for diversity of flora and fauna depending on scale, farming practices, and what these crops displace. However, very large scale biomass crop production (i.e. thousands of acres within Tompkins County) would likely limit biodiversity by displacing varied habitats with uniform cropland.

Key environmental assessment issues for large-scale biomass energy will likely be related to:

- Changes in land use to accommodate biomass crop production
- Impacts from fertilizer, herbicide, or pesticide use
- Cultivation of genetically modified crops
- Transportation of large quantities of biomass feedstocks
- Economic impact from competing demands for forest and agricultural products
- Impacts related to construction and operation of storage and processing facilities
- Air emissions from biomass/biogas combustion
- Ash disposal from direct combustion

Based on these factors and comparison with other options, biomass direct combustion and gasification were both rated LOW in this category.

Technical difficulty

A disadvantage of biomass feedstocks is their relatively low bulk density compared to coal or solid wood. While coal has a bulk density of 800 kg/m3 and hardwoods have a density of 600-900 kg/m3, loose straw has a bulk density of only 80 kg/m3; baled straw 320 kg/m3; and wood chips 250 kg/m3. Combined with the large quantities required for biomass-only options, this has a major effect on the logistics of transportation, storage, and handling of feedstock. Densification of grass crops to pellet form has significantly improved the efficiency of transportation of biomass feedstock; however, this is not practical for the relatively short distance feedstock will be transported to the facility.

Construction and operation of biomass combustion facilities does not pose any significant technical difficulties. However, biomass gasification on such a large scale may present operational challenges due to the limited degree to which it has been demonstrated. For example, Oak Ridge National Laboratory installed a demonstration gasification facility which was shut down after 18 months due to technical issues; it has since been replaced with high-efficiency natural gas boilers. Based on this assessment and comparison with other options, biomass direct combustion was rated HIGH and gasification was rated MEDIUM in this category.

Community impacts

However, the large impact on local land use (~14,000-26,000 acres of biomass crops) and the amount of truck traffic (~7,500-14,000 trucks/year) would have a large impact on the character of the community. Based on these factors and comparison with other options, biomass direct combustion and gasification were both rated LOW in this category.

Community acceptance

The community response to large-scale biomass heating at Cornell would likely be mixed. On the one hand, the use of renewable, GHG-free energy based on local resources would generally be favorably received. On the other hand, the impacts discussed above would undoubtedly generate some opposition. Large-scale biomass energy production has recently received negative press related to depletion of resources, both in NY (the Black River project limiting availability of firewood for homeowners) and the southeastern US (cutting of forests to produce wood pellets for export). Based on this assessment and comparison with other options, biomass direct combustion and gasification were both rated MEDIUM in this category.

Regulatory approval

Key regulatory approval issues with large-scale biomass heating are likely to be related to air emissions, waste disposal, and transportation impacts. Feedstock, ash, and air emission testing could be required. Based on these factors and comparison with other options, biomass direct combustion and gasification were both rated MEDIUM in this category.

Social benefit

Production, harvesting, and transport of biomass crops and forest residue would support numerous local jobs, both directly performing those functions, and indirectly through increased revenues for businesses that supply the farming and trucking industries. Money currently spent on natural gas produced outside of our region would instead stay in the local economy. However, since large-scale biomass energy production is inherently restricted in how widely it can be deployed, it has limited potential for social benefit beyond local job creation. Based on these factors and comparison with other options, biomass direct combustion and gasification were both rated MEDIUM in this category.

Alignment with Cornell mission

Reasonable use of biomass feedstocks from forest management or biomass crop production aligns with Cornell's mission regarding education, research opportunities, and demonstration/outreach. Valuable research could be conducted related to forest management techniques and biomass crop hybrids and production methods. Opportunities for increased renewable energy production and carbon sequestration using feedstocks within a 2 mile radius of Cornell is consistent with Cornell's Land Grant mission to help create rural jobs and promote sustainable agricultural practices beyond the campus borders. This would also provide potential economic benefit to the communities surrounding Cornell if farmers, local businesses, and landowners sell biomass to Cornell. However, the negative local impacts of large-scale biomass production and the lack of scalability of this solution regionally, nationally, or globally limit the value of this alternative compared to others. Based on these factors and comparison with other options, biomass direct combustion and gasification were both rated MEDIUM in this category.

Summary – Biomass combustion & gasification

In summary, the qualitative biomass combustion and gasification rankings in the 12 evaluation categories are as follows:

Table 1.2: Qualitative Assessment of Biomass Options for Campus Heat

Option	Thermal Resource	GHG Offset Potential	Technical Unknowns	Implementation Time	Non-GHG impacts	Cost	Technical Difficulty	Community Impacts	Community Acceptance	Regulatory Approval	Social Benefit	Mission Alignment
Biomass Combustion	M	M	H	H	L	H	H	L	M	M	M	M
Biomass Gasification	M	H	H	H	L	H	M	L	M	M	M	M

2 Earth Source Heat

Background

Earth Source Heat (ESH), also known as an Enhanced Geothermal System (EGS) or "Deep Hot Rock", is an emerging technology that proposes to utilize the heat energy available deep beneath the earth's surface to generate district heating (and potentially some electricity). At least two wells are needed, one for injection of cool water and one for production of hot water. Hydraulic stimulation of the bedrock may also be required to enhance the permeability of the natural bedrock fracture network. Injected water is heated by the earth as it flows through the fractures in the bedrock from the injection well to the production well. This technology is scalable, since additional wells can be installed to produce more hot water. The hot water is sent to a heat exchange facility at the surface, where heat is extracted for distribution to campus via district heating infrastructure. The initial ESH demonstration project would consist of two wells, a surface heat exchange facility, and a hot water distribution system, and would provide partial campus heat while also providing multidisciplinary research opportunities. If the demonstration proves successful, the ESH installation could be expanded by drilling additional wells and converting the entire campus steam system to hot water distribution, thereby providing a majority of campus heating needs.

Cornell's 2009 CAP document [Cornell University, 2009] included ESH as part of the Fuel Mix and Renewables wedge, both as a short-term (1-5 year) alternative (2-well demonstration scale system) and as a long-term (16+ year) alternative (expanded ESH with biomass peaking). The long-term option assumed that three well pairs would cover ~90% of Cornell's annual thermal energy demand, and that the remaining 10% (representing about half of the wintertime peak heating needs) would be supplied by biomass gasification.

Following publication of the 2009 CAP, Cornell submitted a proposal to the DOE under the *Enhanced Geothermal Systems Demonstrations* FOA. The proposal, titled "Geothermal Combined Heat and Power Demonstration in the Eastern US", represented a collaboration between geologists and engineers from Cornell academic units and facilities staff, as well as geothermal and energy engineering consultants, to determine the suitability and develop a detailed plan for installation of a two-well demonstration EGS at Cornell. The proposed scope included reviewing and synthesizing all available geological and geophysical data for the site, an environmental assessment, community outreach, a permitting plan, a seismic study, a well drilling and stimulation plan, conceptual district heating integration plan, cost estimates, and production estimates. This would have laid the groundwork for subsequent projects to install the wells and build the surface heat exchange/distribution infrastructure. While this proposal did not get funded, it remains an excellent summary of the steps needed to prepare for installation of the ESH system

.An initial two-well system (Fig. 1.1) would likely be a binary system using a geofluid (water) and a working (heat transfer) fluid. The geofluid is pumped into the injection well to be heated by the geothermal resource and returns to the surface through the production well. The hot geofluid is run through a heat exchanger to heat the working fluid which is used to produce hot water, steam and/or electricity. The geofluid is returned to the injection well in an essentially closed-loop system. The exact design of the heat exchange and distribution system will depend in part on the temperature and flow rate of the geofluid available from the ground, which will not be known precisely until the first test well is installed.

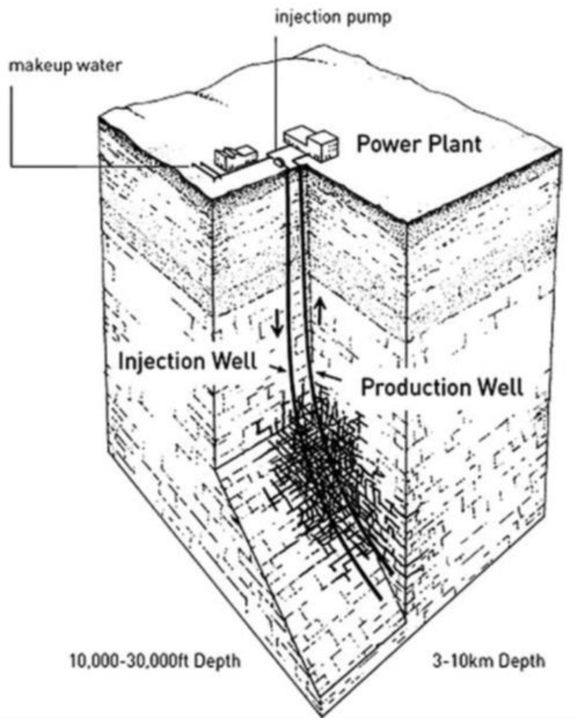

Figure 2.1: generic schematic of an EGS well pair

While shallow ground temperatures are influenced by average surface air temperatures, below a few hundred meters the temperature increases with depth (the “geothermal gradient”) due to heat flow from deeper within the earth and natural radiogenic heat production within the bedrock. Cornell and Ithaca sit atop a relatively shallow geothermal resource compared to other areas of New York and the northeast U.S. (Fig. 2.2).

Typical geothermal gradients worldwide are around 25 C/km; here in the Ithaca area the gradient may be as high as 30 C/km [Blackwell & Richards, 2004; Tester et al., 2010]. Researchers estimate that temperatures of 120–150 C could be tapped at depths of 4.5–6.5 km (Fig. 4b-3), although the exact amount of heat and the depth required cannot be known until a test well is drilled [Blackwell & Richards, 2004; Tester et al., 2010; Shope et al., 2012]. A two-well binary system (Fig. 4b-1) could produce approximately 15 MW of thermal energy – about 450,000 MMBtu per year [Cornell University, 2009]. This equates to about 40% of Cornell’s current annual thermal demand. Two additional well pairs would be required to provide all of the base heating load, and four additional well pairs (a total of 7) would be required to cover wintertime hourly peak heating loads.

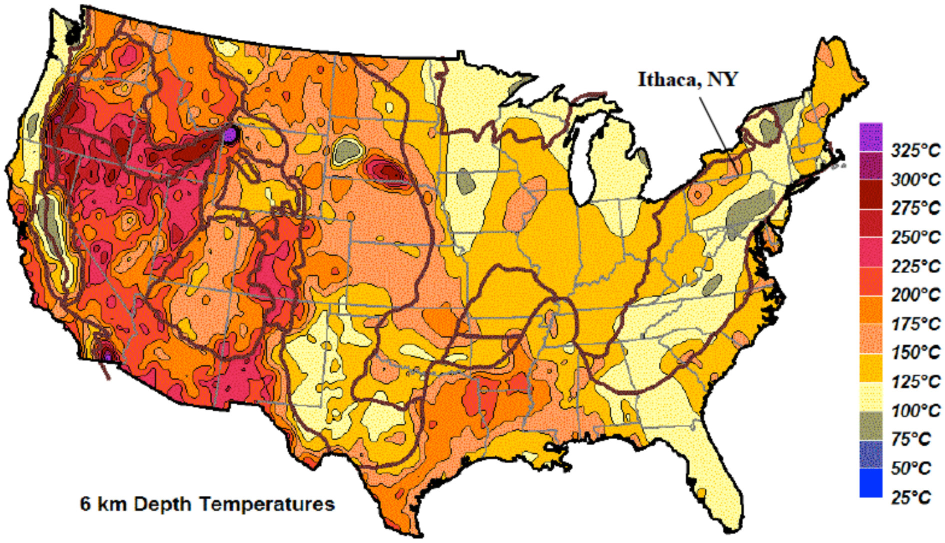

Figure 2.2: Estimated bedrock temperature at 6 km depth [Blackwell & Richards, 2004]

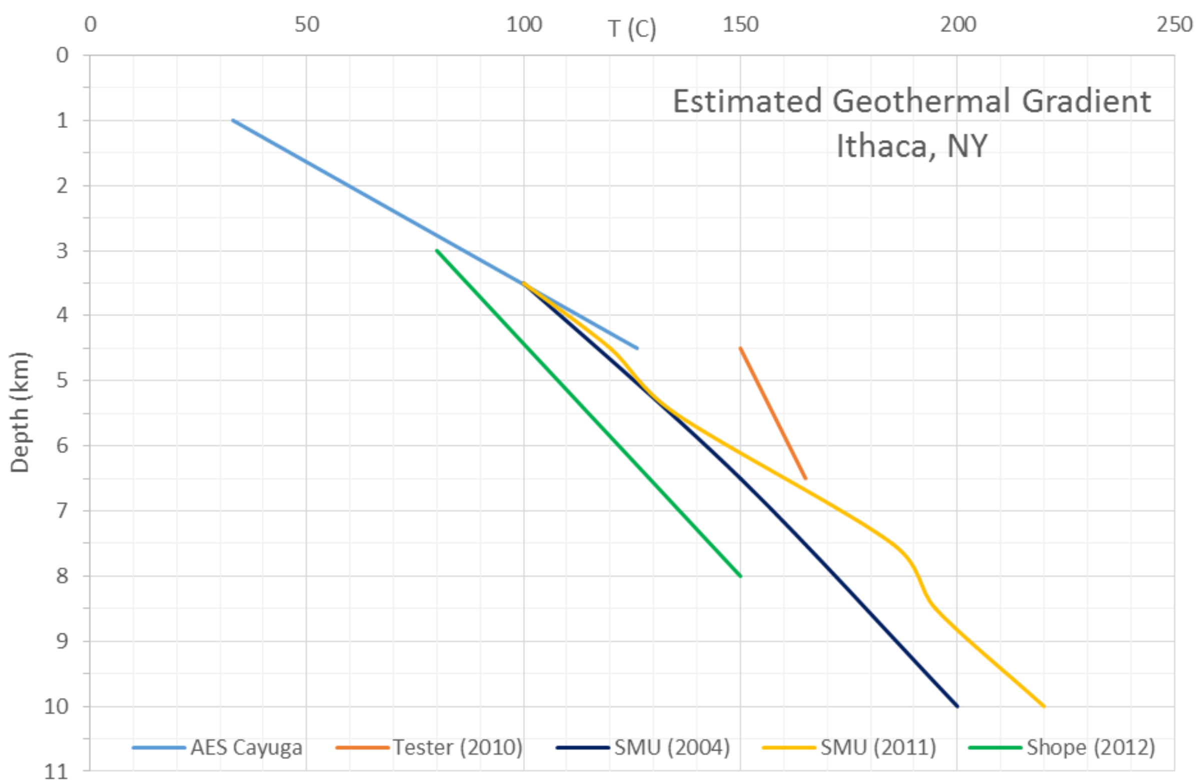

Figure 2.3: Geothermal gradient at Ithaca as estimated by various researchers

Thermal resource

The amount of geothermal heat is vast: across the US, approximately 10^7 EJ of thermal energy is stored between 3-10 km depth, equal to about 100,000 times the annual US energy consumption [2006 MIT]. While only a small fraction of this heat would be economically recoverable, there is a sufficient geothermal resource beneath the Cornell campus to supply all its heat. The feasibility of accessing this resource depends on the difficulty and cost of drilling and reservoir development (i.e. fracture stimulation) at a depth where sufficiently high temperatures exist. The goal would be to produce water at a minimum temperature of 120 C to effectively supply sufficient heating. Prior to installing and operating a demonstration system, there will be uncertainty regarding the amount of recoverable heat and the rate of degradation of the resource (and hence the life expectancy of each well before re-drilling is required).

Conversion to a hot water distribution system would be necessary for efficient use of the resource. Once the wells are installed, while some electricity would be required to pump water through the subsurface reservoir and distribute the heat to campus, the payback is favorable in terms of thermal energy recovered per kWh of electricity consumed. Based on comparison with other options, ESH was rated MEDIUM in this category: the thermal resource is plentiful and could be efficiently utilized once the reservoir is developed, but the actual heat production from each well pair is uncertain, so without any supplemental heat source the system would have to be overdesigned to ensure all peak heating needs were met.

GHG Offset Potential

The entire amount of GHG emissions from CEP operations (~152,000 tons/year) could be replaced with carbon-neutral geothermal heat under this scenario. However, shutting down CCHPP and replacing its electric generation with grid purchases would increase GHG emissions by ~54,000 tons (using the current grid emission factor). The projected increase in electric usage due to ESH is ~6,000 MWh, equivalent to another ~1,500 tons. Therefore the net average annual reduction in GHG emissions would be ~96,700 tons. Based on these estimates and comparison with other options, ESH was rated MEDIUM in this category, as it could offset about 64% of the CEP GHG emissions.

Technical unknowns

The key parameters affecting the thermal production of a geothermal well are the reservoir temperature, the efficiency of the heat exchange between the geofluid and the rock, and the maximum flow rate that can be achieved. Approximately 50-65 MMBtu/hr could be sustained from a well tapping 120-150 C water at a flow rate of ~50 kg/s. Based on existing geological data, researchers have estimated that those reservoir temperatures should be encountered between 4.5-6.5 km depth beneath Cornell [Blackwell & Richards, 2004; Tester et al., 2010; Shope et al., 2012]. At this depth, the bedrock is Precambrian crystalline basement rock that is not well characterized. The flow rate and heat exchange efficiency will largely depend on the characteristics of the bedrock fracture network within this crystalline basement rock. It is anticipated that the existing fractures within the basement rock will not be sufficient for a productive reservoir, and that hydraulic stimulation of the crystalline rock will be required to create a functioning reservoir; hydraulic stimulation methods are not well developed for deep crystalline rocks. Based on these factors and comparison with other options, ESH was rated MEDIUM in this category.

Implementation time

The likely implementation schedule for the ESH project is as follows:
Years 1-5: complete background studies, acquire permits, and install an initial test boring.
Years 5-10: install and test a demonstration system consisting of an initial well pair, heat exchange facility, and a hot water distribution system servicing a portion of campus.
Years 10-15: install and begin operations of a full-scale system with up to 7 well pairs and a hot water distribution system servicing the remainder of campus.
Assuming the technical unknowns described above are resolved during the initial testing and demonstration phases, ESH could be fully implemented in two decades. Based on these factors and comparison with other options, ESH was rated MEDIUM in this category.

Non-GHG environmental impacts

Besides GHG emission reductions, the replacement of natural gas combustion at the CEP with ESH will prevent the release of nitrogen and sulfur oxides. To the extent that natural gas production is offset, ESH will reduce methane emissions, land disturbance, water use, and drilling/fracking waste associated with natural gas extraction.

The following topics are those related to the environmental impact of ESH development that are most likely to merit attention during the environmental assessment process:
Primary issues:

- Water additives used in drilling or stimulation
- Protection of local water resources from contamination
- Reclamation/treatment of water for re-use
- Testing and monitoring of filtered sediment for radiation or chemical hazards

Secondary issues:

- Water availability, storage, and usage
- Impacts on drinking water (this concern may be reduced since area potable water supplies originate from surface-water sources)
- Storm-water impacts during construction or operation
- Containment and safety of storage ponds or tanks
- Air emissions during development and operation

Each of these potential impacts should be manageable with proper planning and implementation. Based on comparison with other options, ESH was rated HIGH in this category.

Cost

The initial capital investment for the ESH system is estimated to be $222M (excluding distribution conversion). The majority of the cost for an ESH system will come from the exceptionally deep bores required to access a sufficient amount of heat. For a depth of 5 km, the estimated cost per well is about $15 million ($30 million for both an injection and an extraction well, including reservoir stimulation). For 7 well pairs, the cost would be ~$210M. Approximately $12M additional capital would be required to construct the power plant. For a relatively low-temperature geothermal resource like the one present in the Ithaca area, it may not be economical to produce steam. A hot water system would provide the most efficient use of the thermal resource. Currently, only the North Campus has a hot water loop, although the possibility of converting other portions of the campus to hot water has been discussed. Capital costs associated with conversion of the entire campus district heating system are estimated to be $100M, although this cost is budget-neutral on a LCC basis due to elimination of steam system upgrades and maintenance.

The principle operating expense for ESH would be the electricity to power the pumps. In addition, electricity currently produced by CCHPP would have to be purchased from the grid. Together, the increased electricity purchases would cost ~$17M/yr (at $0.08/kWh). Maintenance of the heat exchange facilities is expected to cost ~$5M/yr, resulting in total operating expenses of ~$22M/yr.

Based on the $322M total CapEx estimate and comparison with other options (Table 6.2), ESH was rated MEDIUM in this category.

Technical difficulty

As discussed above under Technical Unknowns, ESH involves activities that are novel or rarely completed in our area, particularly deep drilling and stimulation of the basement rock to create the thermal reservoir. Schedule and cost estimates for these tasks are somewhat uncertain, and technical setbacks could be encountered that would extend the project and add costs. Many of these variables will be better constrained after installation of a test boring. In addition, the related work to convert the campus distribution system from steam to hot water has not yet been carefully studied; an assessment of uncertainty and risk associated with that element should be performed. A separate thermal distribution study is being completed in parallel with this report.

Based on these factors and comparison with other options, ESH was rated MEDIUM in this category.

Community Impacts

The following topics are those related to community impacts of ESH development that are most likely to merit attention during the environmental assessment process:

Primary issues:

- Induced seismicity

Secondary issues:

- Traffic Impacts
- Construction and operational safety

Each of these potential impacts should be manageable with proper planning and implementation. These impacts are essentially associated with the initial development only and do not represent long-term (operational) impacts.

Induced seismicity is a hot-button issue today due to recent issues in other locations. A geothermal project in Basel, Switzerland was deemed responsible for causing a magnitude 5.3 earthquake during fluid injection into an active geologic fault. More recently, wastewater injection from oil & gas hydrofracking operations in Oklahoma and Ohio has been implicated as the cause of numerous small earthquakes [Keranen et al., 2014]. Our geology and planned activities are different from these examples, and we do not expect induced seismicity to be a problem during development or operation of ESH. A background seismicity study led by Cornell researchers will be completed during 2015-16 to confirm that the risk is low and to measure background seismic activity as a baseline for comparison during project implementation [Brown et al., 2015]. Development of an induced seismicity mitigation plan will be an important part of the planning for this project.

Based on comparison with other options, ESH was rated HIGH in this category.

Community Acceptance

ESH is likely to receive strong support from both the Cornell community and local community. As a low-impact, efficient means of accessing a renewable resource, it would be an excellent demonstration project and would position Cornell and Ithaca at the forefront of innovative approaches to reducing fossil fuel use and lowering GHG emissions, issues that are important to many in the community.

Because of seismic events induced by high-volume fluid injection into wells at other locations (see previous section), there is the potential for community opposition to develop if people conclude that ESH is similar to these other projects. As part of a background seismicity study being performed during 2015-16 [Brown et al., 2015], Cornell researchers will study community awareness and attitudes toward seismic risk and geothermal energy. This will help guide efforts to engage the community in order to provide complete and accurate information and develop support prior to project implementation.

Based on comparison with other options, ESH was rated HIGH in this category.

Regulatory approval

No major regulatory hurdles are anticipated for development of ESH. NYSDEC is currently (as of June 2015) in the rulemaking process regarding a prohibition on hydraulic fracturing for oil & gas development. While these regulations should not restrict hydraulic stimulation for geothermal development, there is a small risk that the regulations will be unintentionally too broad. This issue is being followed by Cornell staff. An Environmental Assessment will need to be prepared (see discussion in previous sections regarding environmental and community impacts), municipal site plan approval will be required, and drilling permits will be needed from NYSDEC. With proper planning, mitigation, and community outreach, we do not expect that any of these approvals will be problematic. Based on comparison with other options, ESH was rated HIGH in this category.

Social benefit

Successful implementation of ESH would open the door for replication of this technology at many locations in the northeastern US [Reber et al., 2014], with potentially significant implications for GHG reductions regionally and beyond.

Economically, this project will directly employ at least 40 individuals over the life of the project, including academic staff, graduate students, facilities staff, engineering and geology consultants, and other support staff. While some of these staff will not be employed full-time by this work, overall it is estimated (based on an average salary + benefits of $80,000 per full-time-equivalent employee) that approximately 50 person-years of employment will be provided directly by this project; secondary employment will likely multiple this by at least a factor of two. To the extent that this study helps demonstrate the viability of EGS in geologically analogous regions of the U.S., it serves to promote the expansion of commercial exploitation of geothermal energy with attendant job creation in this energy sector, which would dwarf the above figures. This project will also contribute to the community through the development of regional energy options that would have a significant and lasting impact on regional economies and the ability to grow the local tax base.

This represents a direct investment in long-term environmental and economic development opportunities for the region. The results of this study will also directly impact the planning for infrastructure improvements, as regional energy production will be distributed much differently than distribution of imported energy sources. Based on comparison with other options, ESH was rated HIGH in this category.

Alignment with Cornell mission

The ESH project represents an excellent opportunity for integration of research and demonstration. Cornell is one of very few places with the research expertise, geological conditions, physical setting, heat demand, and utility distribution infrastructure to demonstrate ESH. The project would provide numerous opportunities for practical research, and if successful, ESH would serve as a model for low-GHG, renewable heating elsewhere in the northeastern US. Based on these factors and comparison with other options, ESH was rated HIGH in this category.

Summary - ESH

In summary, the qualitative ESH rankings in the 12 evaluation categories are as follows:

Table 2.1: Qualitative Assessment of ESH for Campus Heat

Option	Thermal Resource	GHG Offset Potential	Technical Unknowns	Implementation Time	Non-GHG impacts	Cost	Technical Difficulty	Community Impacts	Community Acceptance	Regulatory Approval	Social Benefit	Mission Alignment
ESH	M	M	M	M	H	M	M	H	H	H	H	H

3 Heat Pumps

Technology overview

The ability to capture hot water return and reheat the water to a usable temperature for further building heat purposes before being sent back to the CEP can be done using a number of technologies involving heat pumps. There are many different kinds of heat pumps, but they all operate on the same basic principle -- heat transfer. This means that rather than burning fuel to create heat, the device moves heat from one place to another. Heat flows naturally along a gradient from a location with a high temperature to a location with a lower temperature. A heat pump uses a small amount of energy to switch that process into reverse, pulling heat out of a relatively low-temperature area, and pumping it into a higher temperature area. Therefore, in heat pump technology, heat is transferred from a "heat source," like the ground or air, into a "heat sink".

An important distinction regarding thermal resources is that heat pumps do not create heat; they simply move it around. They convert electrical energy to thermal energy (heating or cooling) according to the coefficient of performance (COP), which is the ratio of thermal energy output to the input electrical energy. In appropriate applications, this technology can reduce energy usage, but a source of energy generation is still required, either on site or off site.

Highlight Box 2: Projected characteristic grid emissions

Right now the NYS grid is about 56% carbon free (Hydro, Nuclear, Wind, Solar, and Biomass) and the remaining 39%, natural gas, 4% coal, and 1% petroleum. Energy accountant David Frostclapp in Facilities Engineering estimates a grid emission factor about 25% less than the current emission factor, which is around 550lbs/MWh (the upstate eGRID subregion) so by 2035 it is projected to be 412lb CO_2e/MWh.

Air-Source Heat Pumps

Thermal resource

The use of waste heat is known as heat recovery, since the waste heat is recovered and used for other purposes. This setup works best when there is significant overlap in heating and cooling demand. The new Central Energy Facility (CEF) for Stanford's Energy System Innovations (SESI) project is cutting their greenhouse gas emissions by 68% using a heat recovery system. Stanford completed conversion of over 20 miles of steam pipelines to hot-water pipelines across the entire campus in October 2014 and upgraded 155 buildings to hot water piping. A key feature of the CEF is an innovative heat recovery system that takes advantage of Stanford's overlap in heating and cooling needs. In addition to the CEF, the SESI project converted the heat supply of all buildings from steam to hot water. Overall Stanford states that the new system (Figure 3.1) is

70% more efficient than the CHP plant [SESI, 2014]. The heat recovery system meets 93% of the heating load on campus with waste heat. Stanford's heat recovery chillers (HRC) are the first of their kind of this size—ten times the size of any unit the manufacturer, York, has on the market [SESI, 2013]. Each HRC has a 2,500-ton cooling capacity for chilled water and can simultaneously produce 40 million BTUs/hour. The HRCs send out chilled water to campus at 42°F, which returns at 56-60°F. The heat removed from the chilled water is used by the HRC to reheat spent hot water from 130°F to 170°F [SESI, Environmental Comparisons].

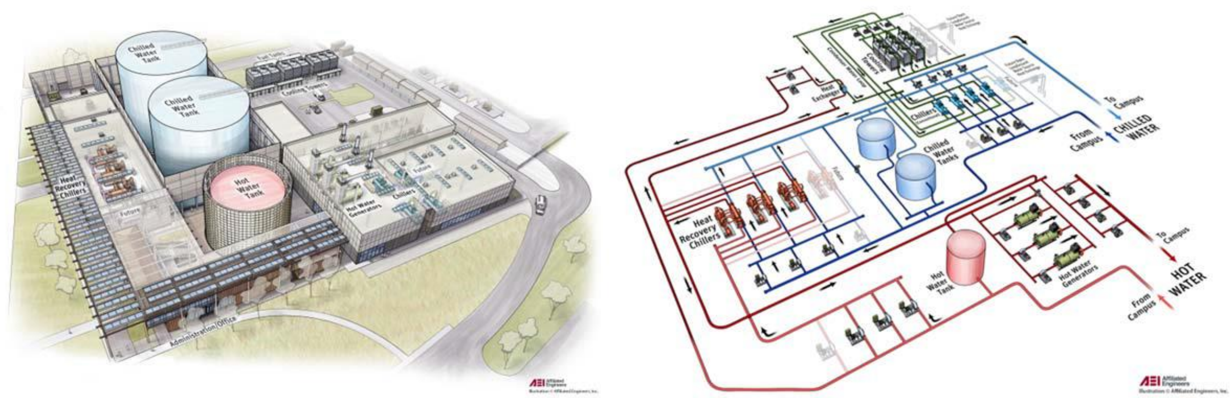

Figure 3.1: Stanford Energy System Innovations (SESI) Combined Heating and Cooling (CHC) facility.

Unfortunately, a system like this does not work well on Cornell's campus because unlike Stanford with a 70% overlap in heating and cooling load, Cornell only has a 20% overlap as seen in Fig. 3.2. Given we have LSC, we would not be able to extract sufficient amounts of waste heat (less than 10%) from the cold water return line and lack of existing thermal reservoirs, employ air source heat pumps is most practical for Cornell campus. Because Ithaca has subfreezing temperatures a majority of the winter months, a reverse cycle chiller would be the best fit air-source heat pump. RCC technology has performance limitations related to the incoming air temperature and humidity. In general, manufacturers rate their equipment based on the entering wet bulb temperature rather than dry bulb temperature. This is due to the fact that a large portion of the energy that the RCC extracts from the air is associated with condensing the available water vapor in the air. Therefore, RCC equipment works better in relatively humid environments. As the outdoor air temperature drops, the ability of the air to carry moisture also decreases which affects the efficiency and output capacity of the equipment. Wet bulb temperature is related to the amount of water carried by the airstream. For this reason, RCC technology works much better in warmer and moister climates. This will favor applications on the West side of the Cascade Mountains in the Pacific Northwest.

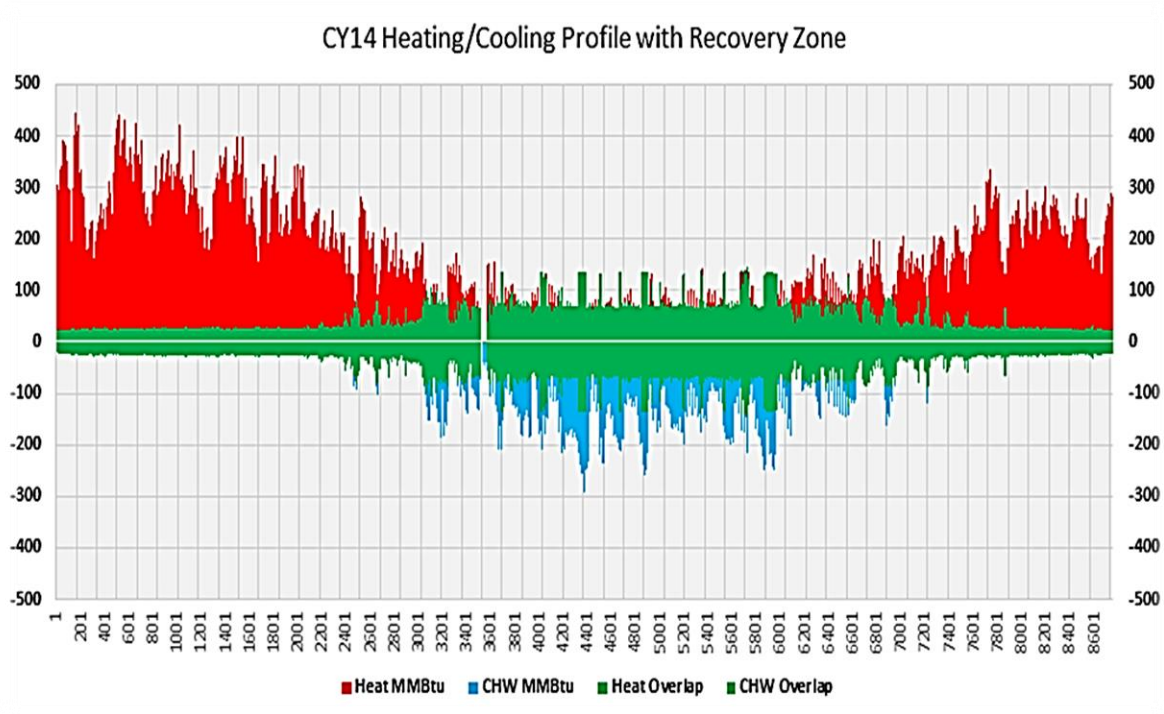

Figure 3.2: Cornell 2014 hourly heating loads (red) and cooling loads (blue). Heat rejected from cooling that could theoretically be recovered to meet some of the heating load is highlighted in green.

Chillers have highest coefficient of performance when they are able to perform both cooling and heating simultaneously. However, because Cornell cools campus primarily with LSC, using a RCC system for heating only would remove any advantage to the dual approach. The amount of electricity required to operate the heating system, and therefore the effectiveness of this strategy to provide heat in an efficient, low-carbon manner, would largely depend on the COP of the system that could be achieved in practice.

In order to have a high COP, operating conditions would need to fall between certain temperature ranges. In fact, the COP will approach 1 (effectively becoming resistance heating) for outdoor temperatures that are -18°C or colder. This is because it becomes increasingly difficult to extract heat from the outdoors (to pump indoors) the colder it gets. Eventually, the heat energy transported becomes equal to the electrical energy input (COP = 1), and the cost of heating becomes much higher. Consequently, heat pumps used for heating are best used during mild winter temperatures.

Based on these issues and comparison with other options, ASHP was rated LOW in this category, as the resource could be sufficient, but there are significant drawbacks in terms of the high electricity consumption.

GHG offset potential

The entire amount of GHG emissions from CEP operations (~152,000 tons/year) would be replaced with air source heat pumps under this scenario. However, with an average COP for heating of around 2.3 (considers an expected COP of 1 during a majority of the winter months), the thermal energy output would approximate the energy input at the point of grid electricity generation (at current electric grid efficiencies). Resulting GHG emissions would depend on the source of electricity used to power the heat pumps. Assuming current electric grid emission factors, the projected increase in electric usage of ~131,000 MWh (assuming heat pump COP=2.3) has associated GHG emissions of ~33,000 tons. In addition, shutting down CCHPP and replacing its electric generation with grid purchases would increase GHG emissions by ~54,000 tons using current grid emission factor although the projected emission by year 2035 is still not expected to be carbon neutral [see Highlight Box 2]. Therefore the net average annual reduction in GHG emissions would be ~65,000 tons. Peak RCHW usage could reach ~117 MW (COP=1), more than quadrupling current campus grid capacity. Based on these estimates and comparison with other options, ASHP was rated LOW in this category, as it could offset ~43% of the CEP GHG emissions.

Technical unknowns

Heat pumps are a well-established technology, so there are few unknowns regarding implementation of this technology. Based on comparison with other options, ASHP was rated HIGH in this category.

Implementation time

The Stanford SESI project was installed in 2 phases over 5 years (2 years for steam to hot water conversion completed in October 2014). We would expect a project like this at Cornell to take place over at least 5 years. Based on comparison with other options, ASHP was rated HIGH in this category.

Non-GHG environmental impacts

Besides GHG emission reductions, the replacement of natural gas combustion at the CEP with heat pumps will prevent the release of nitrogen and sulfur oxides. To the extent that natural gas production is offset, ASHP will reduce methane emissions, land disturbance, water use, and drilling/fracking waste associated with natural gas extraction. ASHP will involve minimal land disturbance; the key environmental assessment issue for implementation of a large-scale heat pump system is the increased demand on the electrical distribution infrastructure. Based on this assessment and comparison with other options, ASHP was rated HIGH in this category.

Cost

The initial capital investment for an air source heat pump system is estimated to be $55M (excluding distribution conversion), including $50M for heat exchange facilities and $757k per heat pump unit and installation. In addition, associated capital costs would include $100M for distribution conversion, $200M for low-temperature building conversions, and $20M for electric upgrades, for a total of $370M. Incremental operating cost including the maintenance of chillers and pumping units and the additional cost for grid purchased electric needs amount to $31M (assuming levelized $6/MMBtu future average gas cost and $0.08/kWhr future electric cost).

Based on these estimates and comparison with other options (Table 6.2), ASHP was rated LOW in this category.

Technical difficulty

The installation of three industrial sized heat pumps would necessitate the addition of a heat exchange facility with upgraded electric load capabilities to be able to tolerate the increased electric demand especially during peak times of the year. Favorable sites for installing pumps and required electric infrastructure upgrades would be on central campus locations in order to provide near site heat boosts; however, this is not ideal and likely will not get approval given the limited building space on central campus.

A heating system based exclusively on heat pumps would be vulnerable to electricity supply disruptions. Institutions such as Stanford and Ball State that rely primarily on heat pumps also have fossil-fuel based backup systems in place. Cornell would need to consider how to provide backup heating capability, which could add significant complexity and cost to the system.

Based on these factors and comparison with other options, ASHP was rated MEDIUM in this category.

Ground-Source Heat Pumps

Technical Description

Geothermal ground-source heat pumps (GSHP) involves using electrically powered heat pumps to extract heat from the ground. Using a ground-coupled system provides a greater COP than air exchange and allows operation during even the coldest weather. Most GSHP systems are designed to provide both cooling and heating seasonally, but with LSC providing most of our cooling, we are evaluating GSHP for its potential to supply heat only. Ball State University in Indiana has installed a GSHP system for heating and cooling, to replace aging coal-fired boilers. Their system (wells, chillers, hot water distribution to 47 buildings) provides 10,000 tons capacity from 3,600 boreholes 400-500’ deep. Scaling this to Cornell’s heating needs, we would need around 10,000 boreholes over an area ~150 acres.

Fig. 3.3: Installation of GSHP wells under athletic fields at Ball State.

The standard design for a GSHP geothermal system involves using heat pumps to extract heat from (or reject heat to) water that is circulated through closed-loop piping installed in boreholes. The boreholes are typically installed to a depth of around 500 feet, which provides a favorable balance between minimizing the number of wells required and avoiding costly deep drilling. The closed-loop piping is grouted within the boreholes to provide both mechanical stability and a thermal connection for exchanging heat with the surrounding soil or rock. Water circulated through the ground loop is then passed through heat pumps in a surface facility, where (in heating mode) heat is extracted and used to boost water temperatures in a secondary loop that provides heat to the buildings. Due to logistical constraints on the size and location of well fields, and the goal of efficient distribution infrastructure, multiple surface heat exchange facilities would likely be needed to service different portions of campus. The Ball State system uses two heat exchange plants for a system about one-third the size that would be required for Cornell.

Fig. 3.4: One of the Ball State heat exchange facilities.

Thermal resource

Almost any amount of thermal energy can be exchanged with the ground given a large enough mass of earth. However, because Cornell cools campus primarily with LSC, using a GSHP system for heating only would result in a thermal imbalance over the course of each year as we continually extracted heat from the ground without replacing it. This would require a greater spacing between wells in order to allow the heat to dissipate, and it is possible that even then, over a period of years, the buildup of heat would reduce system efficiencies significantly. The amount of electricity required to operate the GSHP heating system, and therefore the effectiveness of this strategy to provide heat in an efficient, low-carbon manner, would largely depend on the COP of the system that could be achieved in practice.

Heat pumps cannot produce water hotter than ~180 F. In addition, higher output temperatures result in less efficient operation and lower COPs. Therefore, a heat-pump based heating system would need to operate at relatively low temperatures and would require both conversion to a hot water distribution system and low-temperature building conversions.

Based on these issues and comparison with other options, GSHP was rated LOW in this category, as the resource could be sufficient, but there are significant drawbacks in terms of the annual thermal imbalance and the high electricity consumption.

GHG offset potential

Large amount of electricity would be needed to operate a GSHP system. Preliminary estimates are that average campus electric usage would increase ~43%, and peak usage during the coldest winter weather would approximately double. With a GSHP COP for heating of around 3, the thermal energy output from GSHP would approximate the energy input at the point of grid electricity generation (at current electric grid efficiencies). The carbon footprint would therefore be mainly determined by the grid emission factor associated with the additional electricity consumption.

The entire amount of GHG emissions from CEP operations (~152,000 tons/year) could be replaced with geothermal ground-source heat under this scenario. However, the projected increase in electric usage of ~101,000 MWh (assuming heat pump COP=3) has associated GHG emissions of ~25,000 tons using current electric grid emission factor, and the projected emission by year 2035 is still not expected to be carbon neutral [see Highlight Box 2]. In addition, shutting down CCHPP and replacing its electric generation with grid purchases would increase GHG emissions by ~54,000 tons. Therefore the net average annual reduction in GHG emissions would be ~73,000 tons. Based on these estimates and comparison with other options, GSHP was rated LOW in this category, as it could offset ~48% of the CEP GHG emissions.

Technical unknowns

The primary unknown associated with this option is the thermal response of the ground over time to the imbalanced load resulting from using the system primarily for heating. The loads and response of the well field can be modeled and the system designed to account for this imbalance, but this would be an unusual operating condition for which the models may not be accurate. It is possible that over a period of years, the buildup of heat in the ground would reduce system efficiencies significantly. Based on this factor and comparison with other options, GSHP was rated MEDIUM in this category.

Implementation time

The Ball State project was installed in 2 phases over about 3 years. We could expect this project to take at least 5 years. Based on these estimates and comparison with other options, GSHP was rated HIGH in this category.

Non-GHG environmental impacts

Besides GHG emission reductions, the replacement of natural gas combustion at the CEP with heat pumps will prevent the release of nitrogen and sulfur oxides. To the extent that natural gas production is offset, ESH will reduce methane emissions, land disturbance, water use, and drilling/fracking waste associated with natural gas extraction.

The installation of ~10,000 GSHP wells will require a large land area near campus. Because we use LSC for cooling, the heating and cooling loads would not be balanced and the ground would cool over time. This would require the wells to be spread over a larger compared to a balanced GSHP system of the same size. Assuming a 25-foot well spacing, almost 150 acres of open space would be required. The heterogeneous geology and topography across the Cornell campus would necessitate extensive subsurface characterization during planning phase. Favorable sites for installing wells would include parking lots and athletic fields.

Key environmental assessment issues for implementation of a large-scale heat pump system is the increased demand on the electrical distributions infrastructure. Additionally, key issues with regard to GSHP heating will likely be related to:

- The large area of land disturbance for geothermal wells
- Noise, emissions, and traffic related to the large-scale drilling operation

Based on these factors and comparison with other options, GSHP was rated MEDIUM in this category.

Cost

The initial capital investment for a GSHP heating system is estimated to be $200M (excluding distribution conversion), including $50M for heat exchange facilities and $150M for well installation. In addition, associated capital costs would include $100M for distribution conversion, $200M for low-temperature building conversions, and $10M for electric upgrades, for a total of $510M.

The principle operating expense for GSHP heat would be the electricity to power the pumps and chillers. In addition, electricity currently produced by CCHPP would have to be purchased from the grid. Together, the increased electricity purchases would cost ~$25M/yr (at $0.08/kWh). Maintenance of the heat exchange facilities is expected to cost ~$3M/yr, resulting in total operating expenses of ~$28M/yr.

Based on these estimates and comparison with other options (Table 6-2), ESH was rated LOW in this category.

Technical difficulty

The operation of large heat pumps at the GSHP heat exchange facilities would necessitate the installation of upgraded electric load capabilities to be able to tolerate the increased electric demand, especially during peak heating times. Favorable sites for installing the heat exchange facilities would be near central campus in order to provide heat near demand centers; however, such locations pose challenges and may not receive approval given the limited building space on central campus. Because we use LSC for cooling, the heating and cooling loads would not be balanced; this poses challenges for the design and operation of the system to avoid long-term heat build-up in the well field.

A heating system based exclusively on heat pumps would be vulnerable to electricity supply disruptions. Institutions such as Stanford and Ball State that rely primarily on heat pumps also have fossil-fuel based backup systems in place. Cornell would need to consider how to provide backup heating capability, which could add significant complexity and cost to the system.

Based on these factors and comparison with other options, GSHP was rated MEDIUM in this category.

Common to Both Heat Pump Alternatives

Community impacts

Community impacts from implementation of heat pump technology should be relatively low. Primary impacts from large-scale deployment of GSHP heat pumps would be related to the large land area required and construction impacts (traffic, noise, diesel exhaust). Both ground-source and air-source heat pumps could impact the community by their large electricity demand. This could cause direct effects due to stresses on the electric grid, and indirect effects due to competing demand for resources, especially renewably generated electricity. Based on these factors and comparison with other options, both ASHP and GSHP were rated HIGH in this category.

Community acceptance

The deployment of heat pump systems for heating at Cornell should generally be accepted by the community, as community impacts will be relatively low. However, the relatively limited net GHG reduction associated with these options could generate some opposition from those interested in Cornell's CAP goals. Based on this assessment and comparison with other options, both ASHP and GSHP were rated HIGH in this category.

Regulatory approval

Both air-source and ground-source heat pumps are established technologies that should not have any significant regulatory hurdles. Based on comparison to other options, ASHP and GSHP were both rated HIGH in this category.

Social benefits

Heat pumps can be effectively used on a moderate scale, especially for balanced or simultaneous heating and cooling. Since this technology is already widely available for use, there is limited demonstration value for Cornell to implement such a system. Based on this assessment and comparison with other options, ASHP was rated LOW and GSHP was rated MEDIUM in this category.

Alignment with Cornell mission

Opportunities for research would be limited with this option, since heat pump systems are commonly used and well understood. However, GSHP is an important technology that is likely to be increasingly used on a commercial scale; educational opportunities could be incorporated into the construction and operation of such a system, to demonstrate its practical implementation.

Based on this assessment and comparison with other options, ASHP was rated LOW and GSHP was rated MEDIUM in this category.

Summary – Heat pumps

In summary, the qualitative ASHP and GSHP rankings in the 12 evaluation categories are as follows:

Table 3.1: Qualitative Assessment of Heat Pump Alternatives for Campus Heating

Option	Thermal Resource	GHG Offset Potential	Technical Unknowns	Implementation Time	Non-GHG impacts	Cost	Technical Difficulty	Community Impacts	Community Acceptance	Regulatory Approval	Social Benefit	Mission Alignment
ASHP	L	L	H	H	H	L	M	H	M	H	L	L
GSHP	L	L	M	H	M	L	M	H	H	H	M	M

4 Small Modular Nuclear Reactor

Thermal Resource

The principles for using nuclear power to produce electricity are the same for most types of nuclear reactors. The energy released from continuous fission of the atoms of the fuel is harnessed as heat in either a gas or water, and is used to produce steam. The steam is used to drive the turbines which produce electricity (as in most fossil fuel plants).

The Nuclear Regulatory Commission (NRC) regulates commercial nuclear power plants that generate electricity. There are several types of these power reactors. Of these, only the Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs) are in commercial operation in the United States (Fig. 4.1).

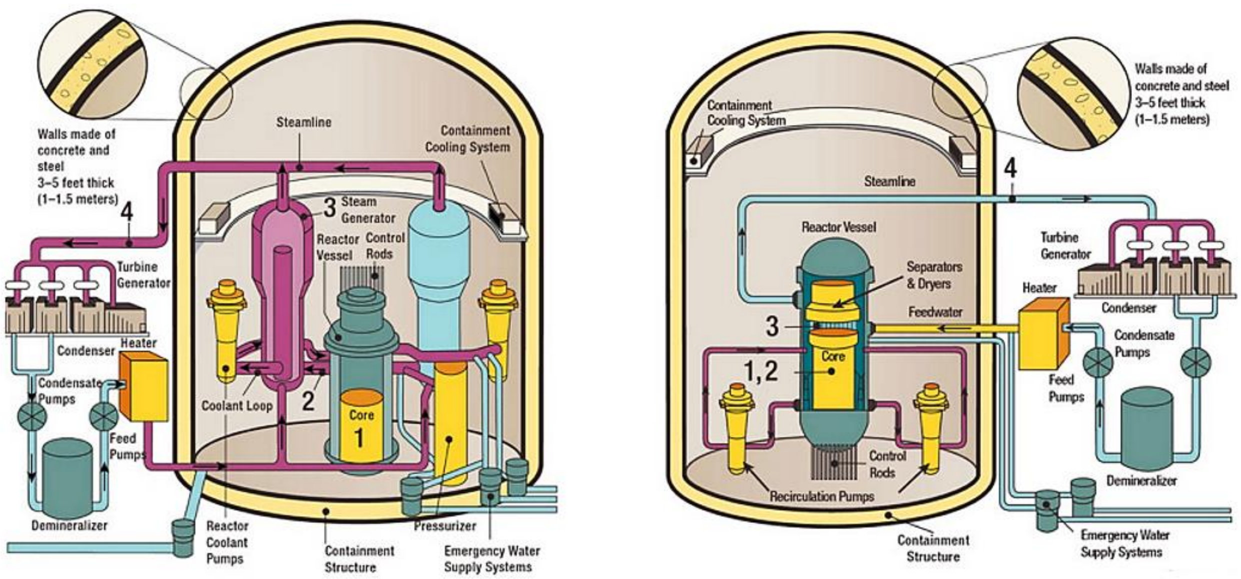

Figure 4.1: Schematic of key components of (left) Pressurized Water Reactors (PWRs) and (right) Boiling Water Reactors (BWRs) [U.S. NRC, 2015].

In a typical design concept of a commercial PWR, pressurized water in the primary coolant loop carries the heat to the steam generator. Inside the steam generator, heat from the primary coolant loop vaporizes the water in a secondary loop, producing steam. PWRs (Pressurized Water Reactors) contain between 150-200 fuel assemblies; whereas, BWRs (Boiling Water Reactors) contain between 370-800 fuel assemblies. Additionally, in a typical design concept of a commercial BWR, a steam-water mixture is produced when very pure water (reactor coolant) moves upward through the core, absorbing heat. The steam-water mixture leaves the top of the core and enters the two stages of moisture separation where water droplets are removed before the steam is allowed to enter the steam line.

The unused steam is exhausted to the condenser. The resulting water is pumped out of the condenser with a series of pumps, reheated, and pumped back to the reactor vessel. The reactor's core contains fuel assemblies that are cooled by water circulated using electrically powered pumps. These pumps and other operating systems in the plant receive their power from the electrical grid. If offsite power is lost, emergency cooling water is supplied by other pumps, which can be powered by onsite diesel generators. Other safety systems, such as the containment cooling system, also need electric power.

Table 4.1 indicates the number of nuclear reactors, type, and size in operation around the world. The International Atomic Energy Agency (IAEA) defines 'small' as under 300 MWe. Small modular reactors (SMR) are designed for serial construction and used collectively to comprise a large nuclear power plant. Today, due partly to the high capital cost of large power reactors generating electricity via the steam cycle and partly to the need to service small electricity grids under about 4 GWe, there is a move to develop smaller units.

Table 4.1 Number of nuclear reactors, type, and size in operation around the world [International Atomic Energy Agency].

Reactor type	Main Countries	Number	GWe	Fuel	Coolant	Moderator
Pressurised Water Reactor (PWR)	US, France, Japan, Russia, China	277	257	enriched UO_2	water	water
Boiling Water Reactor (BWR)	US, Japan, Sweden	80	75	enriched UO_2	water	water
Pressurised Heavy Water Reactor 'CANDU' (PHWR)	Canada	49	25	natural UO_2	heavy water	heavy water
Gas-cooled Reactor (AGR & Magnox)	UK	15	8	natural U (metal), enriched UO_2	CO_2	graphite
Light Water Graphite Reactor (RBMK & EGP)	Russia	11 + 4	10.2	enriched UO_2	water	graphite
Fast Neutron Reactor (FBR)	Russia	2	0.6	PuO_2 and UO_2	liquid sodium	none
	TOTAL	438	376			

GWe = capacity in thousands of megawatts (gross)

Small modular reactors (SMR) offer the advantage of lower initial capital investment, scalability, and siting flexibility at locations unable to accommodate more traditional larger reactors. They also have the potential for enhanced safety and security. The term "modular" in the context of SMRs refers to the ability to fabricate major components of the nuclear steam supply system in a factory environment and ship to the point of use. Even though current large nuclear power plants incorporate factory-fabricated components (or modules) into their designs, a substantial amount of field work is still required to assemble components into an operational power plant. SMRs are envisioned to require limited on-site preparation and substantially reduce the lengthy construction times that are typical of the larger units. SMRs provide simplicity of design, enhanced safety features, the economics and quality afforded by factory production, and more flexibility (financing, siting, sizing, and end-use applications) compared to larger nuclear power plants. Additional modules can be added incrementally as demand for energy increases.

Based on comparison with other options, SMR was rated HIGH in this category.

GHG offset potential

Nuclear power plant reactor power outputs are quoted in three ways:

- Thermal MWt, which depends on the design of the actual nuclear reactor itself, and relates to the quantity and quality of the steam it produces.
- Gross electrical MWe indicates the power produced by the attached steam turbine and generator, and also takes into account the ambient temperature for the condenser circuit (cooler means more electric power, warmer means less). Rated gross power assumes certain conditions with both.
- Net electrical MWe, which is the power available to be sent out from the plant to the grid, after deducting the electrical power needed to run the reactor (cooling and feed-water pumps, etc.) and the rest of the plant.

If using the NuScale Power Module, the thermal capacity is 160 MWt and electrical capacity is 50 MWe (gross) at a 95% capacity factor. Running the SMR at full capacity the entire year would provide enough thermal energy to meet ***at least twice*** the existing thermal demand of campus as well as ***almost twice*** the electric demands of campus. This would reduce Cornell's GHG offsets by at least 152,000 tons of CO2 for both the thermal and electric demands.

Based on comparison with other options, SMR was rated HIGH in this category.

Technical unknowns

Whether nuclear fuel is used only once or recycled for subsequent use, disposal of high-level radioactive byproducts in a permanent geologic repository is necessary. Underground disposal in a specially designed facility is an essential element of a sustainable, integrated used nuclear fuel management program.

SMR waste responsibility lies in the manufacturer with this setup. The Gen4 Module is designed to provide 25 MWe continuously for 10 years on its initial fuel load (compared to an 18 to 24 month cycle for current light water reactors such as the NuScale module). No on-site refueling is required. After 10 years the entire reactor module is replaced.

Based on these factors and comparison with other options, SMR was rated LOW in this category as this technology is still in preliminary study phase and not expected to be in commercial operation before 2030.

Implementation time

The distinct concepts of operation, licensing process, legal and regulatory framework are the main issues for the SMRs deployment. The projected timelines of readiness for deployment of SMR designs generally range from the present to 2025–2030. A 2009 assessment by the IAEA under its Innovative Nuclear Power Reactors & Fuel Cycle (INPRO) program concluded that there could be 96 small modular reactors (SMRs) in operation around the world by 2030 in its 'high' case, and 43 units in the 'low' case***, none of them projected to be in the USA***. (In 2011 there were 125 small and medium units – up to 700 MWe – in operation and 17 under construction, in 28 countries, totaling 57 GWe capacity.)

Four integral pressurized water SMRs are under development in the USA: Babcock & Wilcox's mPower, NuScale, SMR-160 and the Westinghouse SMR. The mPower design consists of two 180 MWe modules and its design certification application is expected to be submitted to the US Nuclear Regulatory Commission (NRC) in the short term. NuScale Power envisages a nuclear power plant made up of twelve modules producing more than 45 MWe and has a target commercial operation in 2023 for the first plant that is to be built in Idaho. The design certification application of NuScale to the NRC is expected in the second half of 2016. The Westinghouse SMR is a conceptual design with an electrical output of 225 MWe, incorporating passive safety systems and proven components of the AP1000. The SMR-160 design generates power of 160 MWe adopting passive safety features and its conceptual design is to be completed in 2015.

Based on these factors and comparison with other options, SMR was rated LOW in this category as this technology is not predicted to be commercially available in the U.S. before 2030.

Non-GHG environmental impacts

Nuclear energy stations do not emit criteria pollutants or greenhouse gases when they generate electricity. The life-cycle emissions from nuclear energy are comparable to other non-emitting sources of electricity like wind, solar and hydropower. Nuclear energy has one of the lowest impacts on the environment of any energy source because it does not emit air pollution, isolates its waste from the environment and requires a relatively small amount of land. However, the uranium fuel is produced from mines that do have an environmental footprint, and there is currently no permanent solution for reprocessing or disposing of radioactive waste from reactor operations in the United States.

The large-scale generation of electricity and the large-scale production of usable water are interdependent. Water use is one of several interrelated environmental considerations that need to be analyzed together when considering electricity generation. The water used to make steam in nuclear power plants remains in strictly enclosed, recirculating systems. Cooling water discharged from a plant must meet federal Clean Water Act requirements and state standards to protect water quality and aquatic life.

Based on these factors and comparison with other options, SMR was rated MEDIUM in this category.

Cost

The initial capital investment for a SMR is speculative. No system suitable for campus now exists; industry prospective documents suggest the range to be $100-250M. Modular components and factory fabrication can reduce construction costs and duration. The principle operating expense for SMRs would be waste management and fuel cost. Again, these numbers are highly speculative. The nuclear Energy Institute reports commercial plants spend $0.79/kWhr for fuel and $1.51/O&M. For a reactor sized for Cornell's demand, expected incremental cost is $34M (doubled for the small scale).

Based on these estimates and comparison with other options (Table 6.2), SMR was rated HIGH in this category.

Technical difficulty

SMR-based power plants can be built with a smaller capital investment than plants based on larger reactors. However, "affordable" doesn't necessarily mean "cost-effective." Economies of scale dictate that, all other things being equal, larger reactors will generate cheaper power. SMR proponents suggest that mass production of modular reactors could offset economies of scale, but a 2011 study concluded that SMRs would still be more expensive per MWe than current larger plants [NEI, 2015]. Others suggest there is no added benefit of SMR technology as compared with large scale nuclear reactors.

The Organization for Economic Cooperation and Development (OECD) and the International Atomic Energy Agency (IAEA) say that uranium resources are adequate to meet nuclear energy needs for at least the next 100 years at present consumption levels. More efficient fast reactors could extend that period to more than 2,500 years [WNA, 2015]. The utility industry is confident that the fuel supply industry will respond to increasing demand. Canada and Australia account for 40% of global uranium production; the United States accounts for 3% [NEI, 2015].

Based on these factors and comparison with other options, SMR was rated MEDIUM in this category.

Community impacts

Direct community impacts would be minimal with implementation of SMR technology.
Based on these factors and comparison with other options, SMR was rated MEDIUM in this category.

Community acceptance

The American public in general, and Ithaca residents in particular, are largely wary of nuclear power both in terms of reactor safety and nuclear waste handling/disposal. Obtaining community acceptance would be a significant challenge, and would require a long-term program of outreach to communicate the relative risks and benefits of SMR technology versus other options.
Based on these factors and comparison with other options, SMR was rated LOW in this category.

Regulatory approval

No new reactor sites have been permitted in the US in many years. The SMR technology has not been approved for commercial use in the U.S. although there are ongoing pilot and simulation studies to encourage credibility and acceptance of the technology within the US.

Based on these factors and comparison with other options, SMR was rated LOW in this category.

Social benefits

In 2012, uranium of U.S. origin accounted for 20 percent of the material used by the owners and operators of U.S. nuclear power plants. The U.S. uranium production industry is working to increase domestic supplies. For example, 2012 expenditures for uranium exploration and mine development in the United States were up more than 300 percent from 2004 [IAEA, 2014].

According to industrial supporters, every dollar spent by the industry at a nuclear plant results in the creation of $1.04 in the local community, $1.18 at the state level and $1.87 at the national level. Similarly, this source estimates that each nuclear plant generates almost $16 million in state and local tax revenue annually [NEI, 2015]. However, these estimates are national figures for the industry at large and may not be as applicable to an SMR at Cornell, where the SMR is expected to be highly modular and the core technology will be developed elsewhere and likely installed by a national construction entity utilizing traveling specialty workers (as is common in the nuclear industry at large); the SMR is also designed to be operated for years without new fuel supplies and with minimal staffing; therefore few post-construction jobs are likely compared to other technologies evaluated.

In the medium-term (20-50 years) nuclear power has the greatest potential of all low-carbon energy sources to provide power on the scale of the forecasted demand, both nationally and worldwide. Demonstration of modern, safe, economical, and scalable nuclear power in the form of Small Modular Reactors could be the key to achieving the significant GHG reductions that are called for to combat serious climate change.

However, the use of an SMR may have more impact nationally and internationally than locally; it does not support the significant use of local resources or local/regional labor generally, and does not demonstrate use of renewable natural resources or technology that can be applied by any but a few international firms; it is therefore unlikely to create new careers for locals.

Based on this assessment and comparison with other options, SMR was rated MEDIUM in this category.

Alignment with Cornell mission

Development and operation of modern SMR technology could potentially provide extensive opportunities for education, research, and outreach on a national scale. However, Cornell no longer has a nuclear engineering program, closed the Ward reactor lab (and its research reactor) 10 years ago in the wake of rising security concerns and administrative costs, and has no current plans to re-initiate a program in nuclear engineering. It is therefore unlikely that any significant aspects of the technology would be developed in-house. Current technology leaders (energy technology corporations) have invested hundreds of millions and are generally highly secretive (due in part to Homeland Security concerns); the comprehensive design and construction of the core plant would be done off-campus and likely out-of-state, providing few if any opportunities for research during the project design stage. While a commitment to construction of an SMR reactor would position Cornell as a leader in a field with tremendous future potential, this positioning is likely to be of more value to certain national leaders and the developer of the commercial technology than to Cornell students or staff; it is considered highly unlikely that Cornell would have any significant technical involvement in either the design or implementation. Compared to other technologies considered, this technology would appear to have the lowest potential for meaningful academic interaction and does not align with the CAP ideal of maintaining energy use within the range of resources available locally and regionally, nor with the land-grant mission of the University.

Of course, demonstrating SMR technology would position Cornell to engage more fully in the public discourse regarding nuclear power, including students, faculty, and the community, with a mission to provide clear and accurate communication of the risks and benefits of the technology. However, it is not clear whether this engagement would be productive or harmful to the University's reputation.

Based on this assessment and comparison with other options, SMR was rated LOW in this category.

Summary - SMR

In summary, the qualitative SMR rankings in the 12 evaluation categories are as follows:f

Table 4.2: Qualitative Assessment of SMR Alternative for Campus Heat

Option	Thermal Resource	GHG Offset Potential	Technical Unknowns	Implementation Time	Non-GHG impacts	Cost	Technical Difficulty	Community Impacts	Community Acceptance	Regulatory Approval	Social Benefit	Mission Alignment
SMR	H	H	L	L	M	H	M	M	L	L	M	L

5 Biomass/ESH (B/ESH)

Background

A hybrid solution we are calling "B/ESH" (for "Biomass with ESH") involves using biomass energy to supplement ESH during periods of peak winter heating demand. This option is attractive because while ESH is well suited to provide steady base load heating, scaling it up to meet peak demand requires the installation of several additional wells, at significant expense, which are only needed for a few days each year. Biomass energy, on the other hand, is well suited to provide lots of heat over short intervals, but has significant limitations on the total amount of energy that can reasonably be generated over the course of a year from biomass grown reasonably close to the Cornell campus. Addition of a biomass gasification system to provide ~9% of the annual heating load could reduce the required size of the ESH system from 7 well pairs to 4 well pairs. The concept of "biomass peaking" is shown on Figure 5.1.1.

The ESH system would operate in the same manner as described above in the Earth Source Heat section, but in addition the biomass gasification-combustion system would be tied in to boost the temperature of the campus heating loop when campus demand exceeded supply from the deep geothermal wells (Fig. 5.1.2).

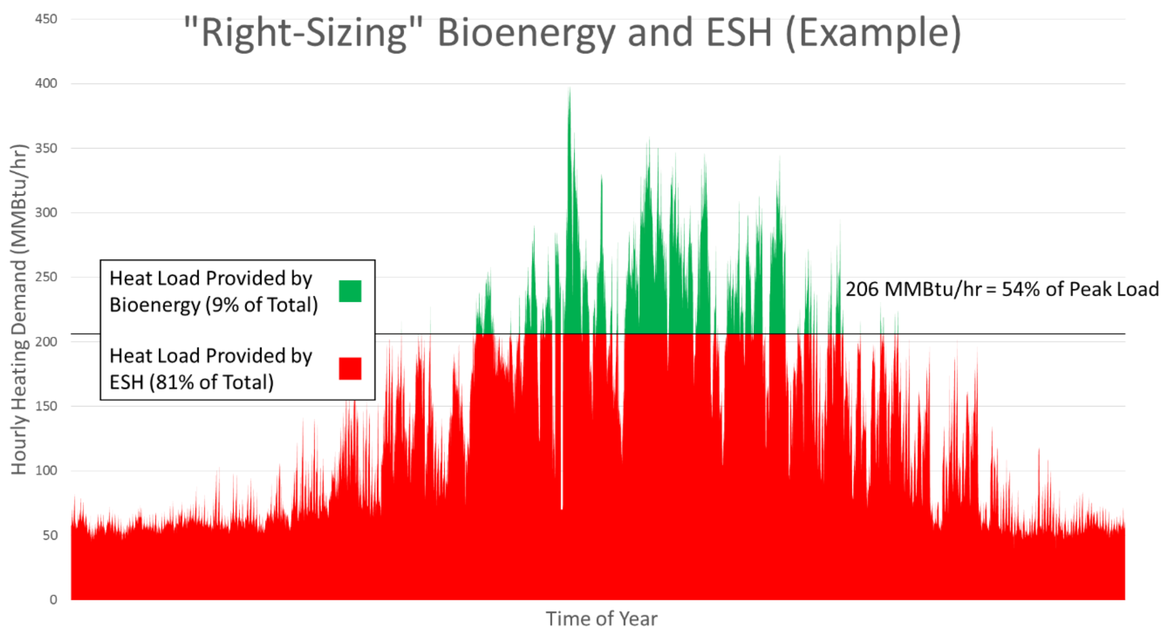

Figure 5.1.1: Example of Cornell's heating demand peaks that could be covered using biomass for 9% of the total campus thermal energy demand.

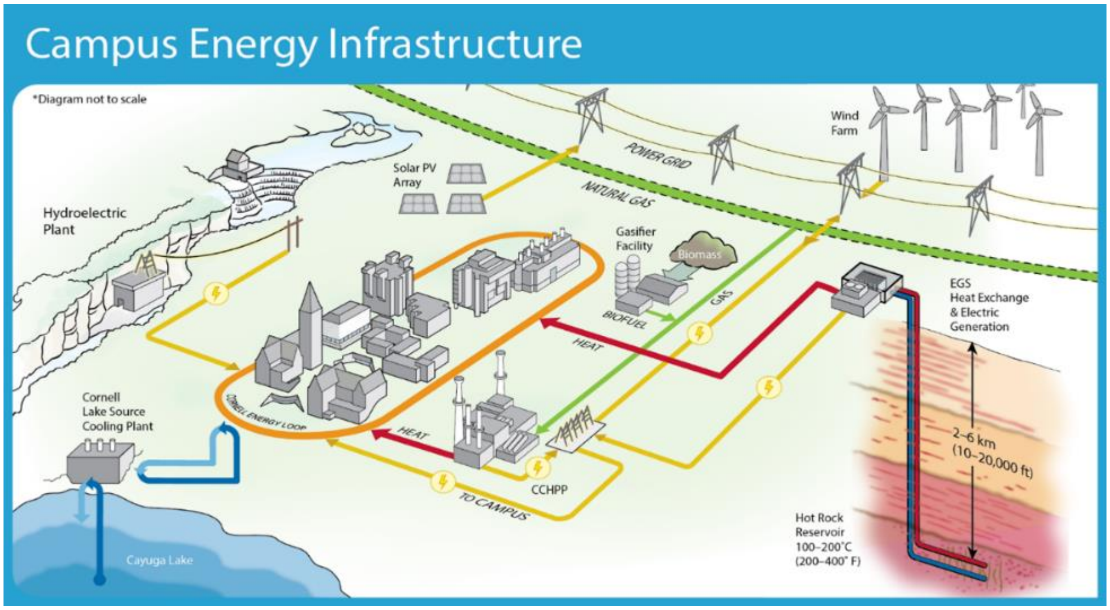

Figure 5.1.2: Example schematic of how geothermal and biomass could be integrated

A conceptual design example is shown in Fig. 5.1.3 [Lukawski et al., 2014]. This particular example includes a provision for backup heat input, an ORC unit for electricity generation, and heat cascading where space heating needs are met first and then the lower-temperature water continues on to provide greenhouse heat. Another possible application of low-grade geothermal heat prior to reinjection would be for drying of biomass feedstocks to increase their energy yields. Details such as these have not yet been determined, and would need to be developed by completion of a feasibility study and a test well to verify the characteristics of the geothermal

The biomass gasification system would operate as described above in the Gasification section, except on a smaller scale.

The B/ESH approach would maximize efficient use of both the geothermal and biomass thermal resources. Previous studies have estimated that ~100,000 MMBtu of peak heating supplied via biomass could be sourced from feedstock primarily produced on Cornell-managed lands [Weinstein, undated; CURBI, 2010], which is a much more sustainable and lower-impact approach than the large-scale production needed for the biomass-only options analyzed above, requiring the equivalent of ~2,300 acres of willow (~1,400 acres of willow plus ~7,200 acres of forest residue) rather than 14,000-26,000 acres of willow. These resources can make a “peaking biogas” option technically viable for the Ithaca campus, with the energy stored as solid biomass until needed.

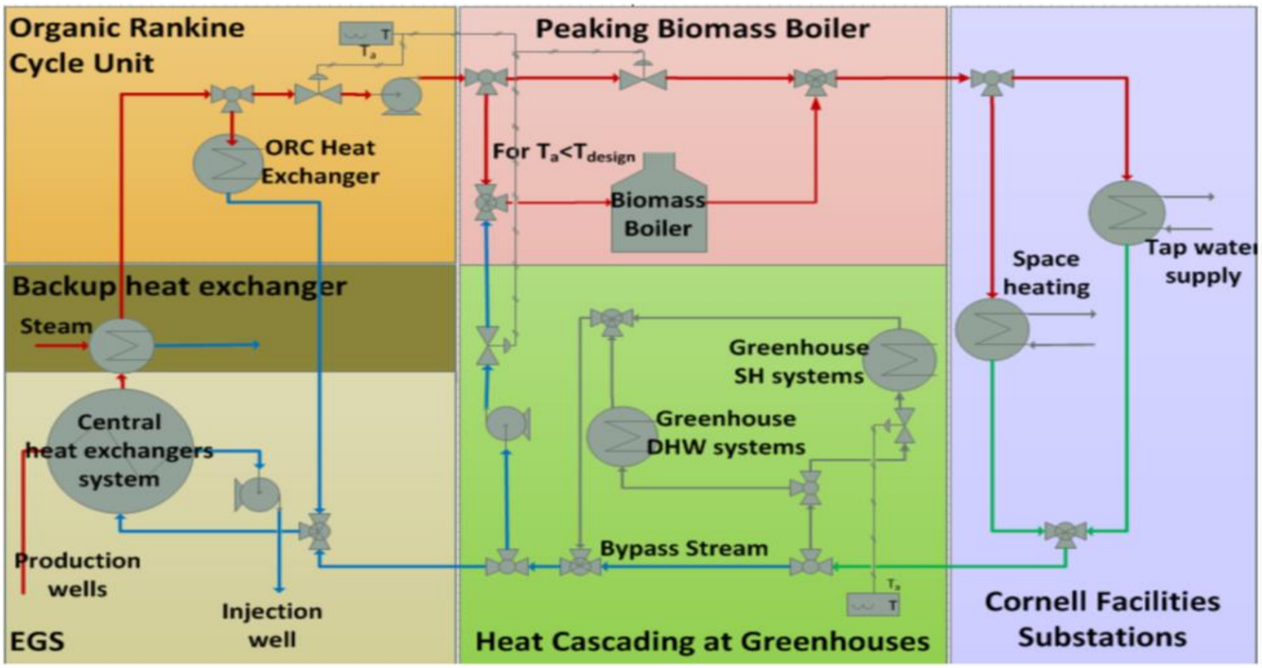

Figure 5.1.3: Conceptual design of ESH with peaking biomass, ORC electricity production, and cascading heat delivery (Lukawski et al., 2013)

This scenario was proposed in the 2009 CAP as a long-term option for heating campus, at which time an overall 10% contribution from biomass to the annual heating load was envisioned. This was carried forward in the 2013 CAP update, which proposed completing an initial demonstration "Hybrid Enhanced Geothermal System (HEGS)" linking an EGS to a biomass-to-biogas system scaled up from CURBI, which during very cold weather would be used to supply the additional electricity and heating needs of campus. The Cornell Energy Institute has extensively researched various aspects of the B/ESH concept, including the nature of the geothermal resource, costs, and concepts for integration into the Cornell district heating system [see Tester et al., 2010; Lukawski et al., 2013; Reber et al., 2014; Tester et al., 2015; Beckers et al., 2015].

Thermal resource

The amount of geothermal heat is vast: across the US, approximately 10^7 EJ of thermal energy is stored between 3-10 km depth, equal to about 100,000 times the annual US energy consumption [2006 MIT]. While only a small fraction of this heat would be economically recoverable, there is a sufficient geothermal resource beneath the Cornell campus to supply all its heat. The feasibility of accessing this resource depends on the difficulty and cost of drilling and reservoir development (i.e. fracture stimulation) at a depth where sufficiently high temperatures exist. Prior to installing and operating a demonstration system, there will be uncertainty regarding the amount of recoverable heat and the rate of degradation of the resource (and hence the life expectancy of each well before re-drilling is required). Once the wells are installed, while some energy would be required to pump water through the subsurface reservoir and distribute the heat to campus, the payback in terms of thermal energy recovered per kWh of electricity consumed would be high.

Although the thermal resource available for ESH is vast, in practice it is limited by the difficulty and cost of accessing the resource. The ability of the hybrid B/ESH system to supply the base heating load with 4 well pairs instead of the 7 well pairs required by the ESH-only alternative represents a significant advantage. Similarly, there is sufficient available biomass in Tompkins County to meet Cornell's heating needs, but this is restricted by logistical, environmental, and community impact concerns. Using biomass for peaking purposes only could reduce the required biomass from 14,000-26,000 acres to ~2,300 acres. Therefore, implementing a hybrid approach to mitigate these issues represents a better option for replacing fossil-fuel heat. Based on comparison with other options, B/ESH was rated HIGH in this category: the combination of ESH for steady base load heating and biomass for supplemental peak heating represents an optimal use of each respective thermal resource.

GHG offset potential

The entire amount of GHG emissions from CEP operations (~152,000 tons/year) could be replaced with carbon-neutral geothermal and biomass heat under this scenario. The projected increase in electric usage due to B/ESH is ~6,000 MWh, equivalent to an increase of ~1,500 tons. However, shutting down CCHPP and replacing most of its electric generation with grid purchases (using the current grid emission factor) would increase GHG emissions by ~49,000 tons. Therefore the net average annual reduction in GHG emissions would be ~102,000 tons. Based on these estimates and comparison with other options, B/ESH was rated MEDIUM in this category, as it could offset ~66% of the CEP GHG emissions.

Technical unknowns

Technical unknowns associated with B/ESH are primarily related to the ESH portion. The key parameters affecting the thermal production of a geothermal well are the reservoir temperature, the efficiency of the heat exchange between the geofluid and the rock, and the maximum flow rate that can be achieved. Approximately 50-65 MMBtu/hr could be sustained from a well tapping 120-150 C water at a flow rate of ~50 kg/s. Based on existing geological data, researchers have estimated that those reservoir temperatures should be encountered between 4.5-6.5 km depth beneath Cornell [Blackwell & Richards, 2004; Tester et al., 2010; Shope et al., 2012]. At this depth, the bedrock is Precambrian crystalline basement rock that is not well characterized. The flow rate and heat exchange efficiency will largely depend on the characteristics of the bedrock fracture network within this crystalline basement rock. It is anticipated that the existing fractures within the basement rock will not be sufficient for a productive reservoir, and that hydraulic stimulation of the crystalline rock will be required to create a functioning reservoir; hydraulic stimulation methods are not well developed for deep crystalline rocks. Based on these factors and comparison with other options, B/ESH was rated MEDIUM in this category.

Implementation time

The likely implementation schedule for the B/ESH option is as follows:

- Years 1-5: complete background studies, acquire permits, and install an initial ESH test boring.
- Years 5-10: install and test a B/ESH demonstration system consisting of a biogas facility, an initial ESH well pair, heat exchange facility, and a hot water distribution system servicing a portion of campus.
- Years 10-15: install and begin operations of a full-scale system with 4-5 well pairs and a hot water distribution system servicing the remainder of campus.

Assuming the technical unknowns described above are resolved during the initial testing and demonstration phases, ESH could be fully implemented by 2035. Based on these factors and comparison with other options, ESH was rated MEDIUM in this category.

Non-GHG environmental impacts

Besides GHG emission reductions, the replacement of natural gas combustion at the CEP with B/ESH will prevent the release of nitrogen and sulfur oxides. To the extent that natural gas production is offset, ESH will reduce methane emissions, land disturbance, water use, and drilling/fracking waste associated with natural gas extraction. As discussed above, previous studies have estimated that B/ESH peak heating supplied via biomass could be sourced from feedstock primarily produced on Cornell-managed lands [Weinstein, undated; CURBI, 2010], which is a much more sustainable and lower-impact approach than the large-scale production needed for the biomass-only options analyzed above. Utilization of biomass energy could be coupled with good forest management practices to remove less desirable tree species and to promote a diversity of maturity in forested plots, which would promote healthy biodiversity.

The following topics are those related to the environmental impact of ESH development that are most likely to merit attention during the environmental assessment process:

Primary issues:

- Water additives used in drilling or stimulation
- Protection of local water resources from contamination
- Reclamation/treatment of water for re-use
- Testing and monitoring of filtered sediment for radiation or chemical hazards

Secondary issues:

- Water availability, storage, and usage
- Impacts on drinking water (this concern may be reduced since area potable water supplies originate from surface-water sources)

- Storm-water impacts during construction or operation
- Containment and safety of storage ponds or tanks
- Air emissions during development and operation
  Potential cultivation of genetically modified crops
  Air emissions from biomass/biogas combustion

Each of these potential impacts should be manageable with proper planning and implementation. Based on comparison with other options, B/ESH was rated HIGH in this category.

Cost

The initial capital investment for the B/ESH system (excluding distribution conversion) is estimated to be $180M. The majority of the cost for the B/ESH system will come from the deep boreholes required to access a sufficient amount of heat. For a depth of 5 km, the estimated cost per well is about $15 million ($30 million for both an injection and an extraction well, including reservoir stimulation). For 4 well pairs, the cost would be ~$120M. Approximately $16M additional capital would be required to construct the power plant and related infrastructure. The biomass gasification system with associated storage would cost ~$44M. Capital costs associated with conversion of the entire campus district heating system are estimated to be an additional $100M, although this cost is budget-neutral on a LCC basis due to elimination of steam system upgrades and maintenance.

The principle operating expense for B/ESH would be the electricity to power the pumps. In addition, electricity currently produced by CCHPP would have to be purchased from the grid. Together, the increased electricity purchases would cost ~$17M/yr (at $0.08/kWh). Production of biomass fuel (primarily from Cornell land) is expected to cost <<$1M/yr, and therefore is not included in this first order estimate. Maintenance of the biomass and heat exchange facilities is expected to cost ~$6M/yr, resulting in total operating expenses of ~$23M/yr.

Based on the $280M total CapEx estimate and comparison with other options (Table 6.2), B/ESH was rated MEDIUM in this category.

Technical difficulty

As discussed above under Technical Unknowns, B/ESH involves activities that are novel or rarely completed in our area, particularly deep drilling and stimulation of the basement rock to create the thermal reservoir. Schedule and cost estimates for these tasks are somewhat uncertain, and technical setbacks could be encountered that would extend the project and add costs. Many of these variables will be better constrained after installation of a test boring. In addition, the related work to convert the campus distribution system from steam to hot water has not yet been carefully studied; an assessment of uncertainty and risk associated with that element should be performed. A separate thermal distribution study is being completed in parallel with this report.

Biomass gasification, while a relatively immature technology, is already being performed at numerous facilities and does not present significant technical challenges.

Based on these factors and comparison with other options, B/ESH was rated MEDIUM in this category.

Community Impacts

The following topics are those related to community impacts of ESH development that are most likely to merit attention during the environmental assessment process:

Primary issues:

- Induced seismicity

Secondary issues:

- Traffic Impacts
- Construction and operational safety
- Impacts related to construction and operation of storage and processing facilities

Each of these potential impacts should be manageable with proper planning and implementation, and the first two impacts are associated only with the construction phase of work.

Induced seismicity is a hot-button issue today due to issues in other locations. A geothermal project in Basel, Switzerland was deemed responsible for causing a magnitude 5.3 earthquake during fluid injection into an active geologic fault. More recently, wastewater injection from oil & gas hydrofracking operations in Oklahoma and Ohio has been implicated as the cause of numerous small earthquakes [Keranen et al., 2014]. Our geology and planned activities are different from these examples, and we do not expect induced seismicity to be a problem during development or operation of B/ESH. A background seismicity study led by Cornell researchers will be completed during 2015-16 to confirm that the risk is low and to measure background seismic activity as a baseline for comparison during project implementation [Brown et al., 2015]. Development of an induced seismicity mitigation plan will be an important part of the planning for this project.

Based on this analysis and comparison with other options, ESH was rated HIGH in this category.

Community Acceptance

B/ESH is likely to receive strong support from both the Cornell community and local community. As a low-impact, efficient means of accessing renewable resources, it would be an excellent demonstration project and would position Cornell and Ithaca at the forefront of innovative approaches to reducing fossil fuel use and lowering GHG emissions, issues that are important to many in the community.

Because of seismic events induced by high-volume fluid injection into wells at other locations (see previous section), there is the potential for community opposition to develop if people conclude that B/ESH is similar to these other projects. As part of a background seismicity study being performed during 2015-16 [Brown et al., 2015], Cornell researchers will study community awareness and attitudes toward seismic risk and geothermal energy. This will help guide efforts to engage the community in order to provide complete and accurate information and develop support prior to project implementation.

Based on this analysis and comparison with other options, ESH was rated HIGH in this category.

Regulatory approval

No major regulatory hurdles are anticipated for development of B/ESH. NYSDEC is currently (as of June 2015) in the rulemaking process regarding a prohibition on hydraulic fracturing for oil & gas development. While these regulations should not restrict hydraulic stimulation for geothermal development, there is a small risk that the regulations will be unintentionally too broad. This issue is being followed by Cornell staff. An Environmental Assessment will need to be prepared (see discussion in previous sections regarding environmental and community impacts), municipal site plan approval will be required, and drilling permits will be needed from NYSDEC. With proper planning, mitigation, and community outreach, we do not expect that any of these approvals will be problematic. Based on this analysis and comparison with other options, B/ESH was rated HIGH in this category.

Social benefits

Successful implementation of B/ESH would open the door for replication of this technology at many locations in the northeastern US [Reber et al., 2014], with potentially significant implications for GHG reductions regionally and beyond.

Economically, this project will directly employ at least 40 individuals over the life of the project, including academic staff, graduate students, facilities staff, engineering and geology consultants, and other support staff. While some of these staff will not be employed full-time by this work, overall it is estimated (based on an average salary + benefits of $80,000 per full-time-equivalent employee) that approximately 50 person-years of employment will be provided directly by this project; secondary employment will likely multiple this by at least a factor of two. To the extent that this study helps demonstrate the viability of EGS in geologically analogous regions of the U.S., it serves to promote the expansion of commercial exploitation of geothermal energy with attendant job creation in this energy sector, which would dwarf the above figures. This project will also contribute to the community through the development of regional energy options that would have a significant and lasting impact on regional economies and the ability to grow the local tax base.

This represents a direct investment in long-term environmental and economic development opportunities for the region. The results of this study will also directly impact the planning for infrastructure improvements, as regional energy production will be distributed much differently than distribution of imported energy sources.

Based on this analysis and comparison with other options, B/ESH was rated HIGH in this category.

Alignment with Cornell mission

The B/ESH project represents is an innovative strategy that would incorporate collaborative research across many departments at Cornell. The Cornell Energy Institute and CURBI would likely be deeply involved in research and development to determine the optimal approach for integrating these technologies. Demonstration and outreach opportunities would be plentiful; this project would be a prime opportunity to combine the education, research, and extension aspects of Cornell's mission. Construction and operation of a gasification facility at Cornell would provide valuable opportunities to test various feedstocks as well as processing and combustion techniques. As mentioned above, Cornell is one of very few places with the research expertise, agricultural resources, geological conditions, physical setting, heat demand, and utility distribution infrastructure to demonstrate both ESH and advance bioenergy production and utilization. Based on these factors and comparison with other options, B/ESH was rated HIGH in this category.

Summary – B/ESH

In summary, the qualitative B/ESH rankings in the 12 evaluation categories are as follows:

Option	Thermal Resource	GHG Offset Potential	Technical Unknowns	Implementation Time	Non-GHG impacts	Cost	Technical Difficulty	Community Impacts	Community Acceptance	Regulatory Approval	Social Benefit	Mission Alignment
B/ESH	H	M	M	M	H	M	M	H	H	H	H	H

6 Summary of Evaluations

The overall conclusion of this study is that the biomass/ESH option has significant advantages over all stand-alone options and the other hybrid options. While it poses slightly higher risks in terms of technical unknowns and difficulty, it is competitive in cost and has clear advantages in terms of the quality of the resource, community impacts, regulatory approvals, social benefits, and alignment with Cornell's mission. Large-scale biomass with supplemental heat pumps could potentially be implemented, but with significant challenges in terms of the resources required (land, electricity), operating costs, and environmental & community impacts. Heat exchange options are technically feasible, but have limited GHG offset potential due to the large amount of grid electricity required; they also have high capital and operating costs. Small Modular Reactors have tremendous potential to provide ample GHG-free energy, but technological uncertainty, regulatory hurdles, community opposition, and lack of alignment with our academic mission limit their appeal as a solution at Cornell.

A summary of the strengths and weaknesses of each option across these categories is presented in Table 6.1; detailed discussion of each is presented in the next section.

Table 6.1: Summary of qualitative evaluations of thermal resource options

	Environmental					Economic		Social				Inst.
Option	Thermal Resource	GHG Offset Potential	Technical Unknowns	Implementation Time	Non-GHG impacts	Cost	Technical Difficulty	Community Impacts	Community Acceptance	Regulatory Approval	Social Benefit	Mission Alignment
Biomass Combustion	M	M	H	H	L	H	H	L	M	M	M	M
Biomass Gasification	M	H	H	H	L	H	M	L	M	M	M	M
ESH	M	M	M	M	H	M	M	H	H	H	H	H
ASHP	L	L	H	H	H	L	M	H	M	H	L	L
GSHP	L	L	M	H	M	L	M	H	H	H	M	M
SMR	H	H	L	L	M	H	M	M	L	L	M	L
[A] B/ESH	H	M	M	M	H	M	M	H	H	H	H	H

L = low, M= medium, H = high (see discussion in Analysis of Alternatives sections)
Ranking indicates how well the technology meets campus goals in that category; e.g. SMR requires less electric so it scores HIGH in that category]

Table 6.2: Comparison of Potential Thermal Resource Options

Technology	CAPEX	OPEX (annual)	Electrical Requirement w/Technology in place	Net annual GHG reduction (tons)	Land Area Required (acres)	Fuel trucks per year
Business as Usual (for comparison)	$120M	$10M	~35,000 MWh annually (remainder self-generated)	None	N/A	N/A
Earth Source Heat (ESH)	$322M	$22M	216,000 MWh annually	97,000	5 [1]	N/A
Biomass Combustion (BC)	$220M	$26M	194,000 MWh annually	103,000	14,000 [2]	~7,500
Biomass Gasification (BG)	$240M	$10M	~60,000 MWh annually (remainder self-generated)	137,000	26,000 [2]	~14,000
Ground Source Heat Exchange (GSHP)	$510M	$28M	~320,000 MWh annually	73,000	150 [3]	N/A
Air Source Heat Pumps	$370M	$31M	~350,000 MWh annually	65,000	5 [4]	N/A
Small Modular Nuclear Reactor (SMR)	$100-250M	$34M	None (all self-generated)	150,000	10 [5]	N/A
B/ESH "Hybrid"	$280M	$23M	200,000 MWh annually	102,000	5 [1] 2,300 [2]	~1,250

[1] Wellhead infrastructure and heat exchange facility
[2] Biomass crop production (assumed to be all shrub willow for comparison purposes)
[3] Geothermal wells
[4] Heat exchange facilities
[5] Reactor/cooling facility
* Scenario 1 = heat pumps, with excess electrical needed powered by on-site bioenergy electricity generation; Scenario 2 = bioenergy limited to estimated production from CU land; remaining electricity required from other means

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