USEPA Proposed Revisions to ENERGY STAR Program for Boilers

Technical notes and comments prepared by Raymond J. Albrecht PE

July 7, 2023

Summary Biography for Raymond J. Albrecht PE

Consulting environmental engineer with over 40 years of experience in the subject area of renewable heating technologies. Technical specialties have included electric and thermally-driven heat pumps, solid and liquid renewable fuels in thermal applications, and power generation. Have performed work for manufacturing companies, trade organizations and environmental agencies relating to equipment design, fuel utilization, regulatory permitting, emissions testing, and life-cycle analysis. Member of the ISO New England Planning Advisory Committee and active with the ISO New England Load Forecasting Committee. Spent 30 years as lead technical staff person for heating technology and fuels R&D at the New York State Energy Research and Development Authority (NYSERDA). NYSERDA work also included field testing of first ground-source heat pump installation in northeastern United States back in early 1980s. Principal of Raymond J. Albrecht LLC for the past 15 years.

Graduate of Cornell University with a Bachelor of Science degree in engineering and a Master of Science degree in Theoretical and Applied Mechanics. Life Member of the American Society of Heating, Refrigerating and Air-conditioning Engineers (ASHRAE) and past chairman of ASHRAE Technical Committee 6.10 for Fuels and Combustion. Received the ASHRAE Distinguished Service Award in 2015. Licensed professional engineer (No. 056935) in New York. Served as a 1st Lt (Infantry) in the United States Army during 1970-80 (active plus reserve) and am a graduate of the US Army Infantry Officer School at Fort Benning, Georgia. Fulfilled my active reserve obligation in northeastern Kenya, near the Somali border.

PRINCIPAL COMMENTS

1) EPA is commended for its long list of accomplishments by the ENERGY STAR program in support of energy efficiency and the fight against climate change. Since its inception in 1992, the ENERGY STAR program has established partnerships with thousands of private industry companies, utilities, state and local governments and environmental organizations to identify and promote efficient technologies in a broad array of product categories.

   From its early successes in the computer and photocopier categories, the ENERGY STAR program has grown continuously to include heat pumps, furnaces, boilers, dishwashers, air conditioners, refrigerators and freezers, clothes washers and dryers, lighting, TVs, room air cleaners, vending machines, electric vehicle chargers, and an ever-growing list of new product types. The program has also importantly addressed the opportunity for achieving energy efficiency in whole buildings in the residential, commercial, institutional, and industrial sectors.

   The ENERGY STAR program has proven that public-private partnerships can achieve both economic growth and environmental protection. The program has contributed to the creation of millions of well-paying jobs and billions of dollars of capital investment. At the same time, the program has achieved huge environmental benefits through the avoidance of billions of metric tonnes of greenhouse gas emissions.

2) There is increasing urgency to decarbonize the building sector. Decarbonization in residential and commercial buildings will require more than just efficiency gains in fuel-fired heating appliances. I would encourage the EPA ENERGY STAR program to support the combined use of high-efficiency heating equipment and low carbon fuels to achieve net zero greenhouse gas emissions by the year 2050.

3) Air-to-Water heat pumps experience three fundamental limitations in their application to hydronic heating systems for residential and commercial buildings. The first challenge relates to the achievable heating capacity in a building that uses traditional baseboard heating. Hydronic baseboards are typically rated in Btu/hr capacity at temperatures ranging from 150 to 180 deg F. Operation of hydronic baseboards at supply temperatures of 130 deg F or lower can decrease thermal output by more than 50% which then creates a capacity shortfall during cold weather.

   The second challenge relates to the heat pump efficiency decrease that results from providing a hydronic supply temperature of 130 deg F rather than a warm air furnace supply temperature of 95 deg F. As the two graphs in Figure 1 illustrate, the COP of an air-to-water heat pump will typically be about 20% lower than for an air-to-air heat pump at a given outdoor temperature. This substantially reduces the energy savings achievable by air-to-water heat pumps compared to traditional natural gas and oil-fired heating systems. Additional analysis, as described further in the supplemental comments included later in the document, shows that air-to-water heat pumps and B50 biodiesel blends have approximately the same carbon intensities during mild weather, but then the B50 biodiesel blends show substantially lower carbon intensity during the remainder of the heating season.

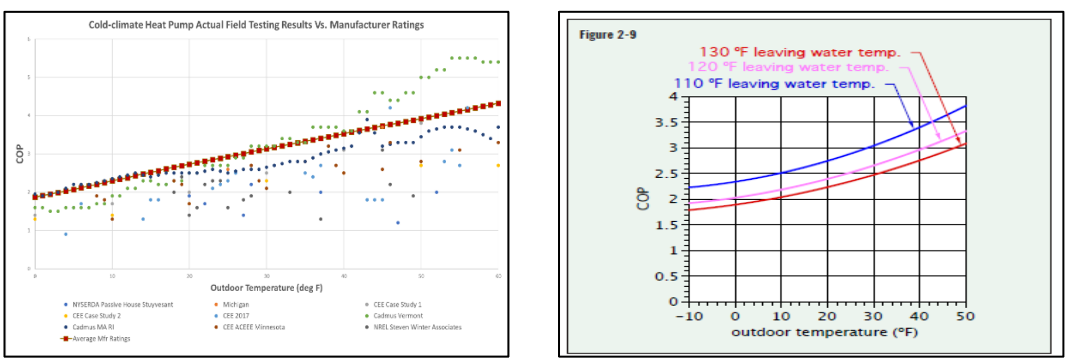


Figure 1. Air-to-Air and Air-to-Water Heat Pump COPs vs. Outdoor Temperature

   The third challenge relates to air-to-water heat pump efficiency during very cold weather. Air-to-air heat pumps typically lose substantial efficiency and capacity when the outdoor temperature drops below 5 deg F, thus when the difference between the indoor and outdoor temperature becomes 90 deg F or more. The pressure lift necessary for heat pump operation starts to overload the compressor unit. Below 5 deg F, many air-to-air heat pumps show efficiency levels that are just barely above that of electric resistance heat, thus posing severe loads on the power grid. Because of higher supply temperature requirements, the same type of compressor pressure problem begins at an outdoor temperature of about 30 deg F.

4) Air-to-water heat pumps therefore provide effective and efficient heating capability in most existing buildings only at outdoor temperatures in the range of about 30 deg F and higher. Back-up heating capacity will still be required during cold weather with consequent capital and operating cost burdens.

5) A recent analysis of heat pump performance in Massachusetts found that the use of renewable electricity for heat pump systems would achieve approximately 8 tons of CO_2 savings per year in a single-family residential unit. As described in greater detail in the supplemental comments later in this document, the 2.7 million residential units in Massachusetts would achieve annual CO_2 savings of approximately 22 million tons per year. The 30-year cumulative savings would be approximately 650 million tons of CO_2. Including the commercial building sector, which adds about 50% to the total heating load, the total 30-year savings for the combined residential and commercial building sector would be approximately 960 million tons of CO_2.

   The total capital cost of $674 billion noted in the analysis (see further details in the Supplemental Technical Notes section of this document) yielded a capital cost figure of approximately $700 per ton of CO_2 savings. This dollar amount is much higher than the commonly used figures for the social cost of carbon. The high costs for a complete package of renewable power generation, transmission and distribution, plus onsite equipment, indicate the need for allowing more cost-effective decarbonization pathways.

6) The pace of renewable power generation development in the northeastern United States, even under the most optimistic policy scenarios, is too slow to meet the additional grid loads that would be incurred by planned electrification of space heating. Supply chain issues, higher interest rates, and workforce training requirements have become significant barriers to rapid deployment of solar and wind projects. There is a growing need for parallel pathways toward decarbonization in the building sector.

7) Heat pump loads that grow more quickly than renewable power generation capacity will yield the unfortunate result of increasing, not decreasing, fossil fuel consumption for power generation, especially by peaking units. Peaker units often suffer poor efficiency and produce high emissions levels. See https://www.cleanegroup.org/wp-content/uploads/The-Peaker-Problem.pdf for some informative data on the negative environmental and public health impacts of peaking operation in LMI and EJ communities.

8) Carbon savings achieved by heat pumps during the next few decades will be limited to those which are achievable with natural gas-fired generation, until existing grid loads are fully met by renewable power generation, and further renewable capacity can then be dedicated to heat pump operation. There will thus be a significant time delay in the achievement of fully renewable electrification of thermal applications, which in turn impedes the accomplishment of our environmental goals, especially within the shorter timeframes that are becoming necessary to avoid catastrophic climate change.

9) EPA ENERGY STAR proceedings should incorporate the important factor of power generation efficiency in the overall system efficiency of heat pumps. Heat pump system efficiency is sensitively dependent on generation efficiency. While the most modern generation plants in the

northeastern United States can achieve fuel-to-electric efficiencies of almost 50% during constant base-load operation, the bulk of generation plants operated at the margin for temperature-variable loads operate in the range of 40% down to under 20% efficiency, and sometimes even lower, especially during morning and evening peak periods. The resulting fuel-to-electric-to-heat efficiency with a mid-range (30% efficiency) generation unit providing electricity to a heat pump with a real-world COP = 2.0 at 20 deg F during cold weather will be only 60%, thus substantially lower than an ENERGY STAR furnace or boiler.

10) Reducing carbon emissions now is more valuable than reducing the same amount of emissions later. This significant and often overlooked principle is frequently absent from policy discussions, which, for example treat a reduction of CO_2 in 2023 with the same weight as a reduction in 2050. Renewable fuels such as biodiesel can achieve carbon savings today rather than being dependent on future improvements to the power grid, and thus can enable us to achieve a faster start in our path to a sustainable energy future.

11) The ENERGY STAR program has achieved considerable success in the past based on partnerships between public and private organizations. The ENERGY STAR program could forge a public-private partnership with both the renewable fuels industry and heating equipment manufacturers, under which ENERGY STAR appliances would combine high efficiency with the capability for using renewable fuels.

SUPPLEMENTAL TECHNICAL NOTES

12) As shown by recent ISO New England and New York ISO planning studies, required grid capacities in the northeastern United States would double due to heat pump loads, even with ambitious weatherization efforts to reduce building envelope losses, and without considering further grid load increases due to electric vehicles. Consideration of capital investment requirements, supply chain issues and workforce training requirements will support the case for establishing supplemental pathways toward decarbonization.

    A recent technical and economic analysis indicated that an installed nameplate capacity of 10,000 MW of offshore wind plus 10,000 MW of solar PV power will approximately meet the needs of residential and commercial heat pumps in the Massachusetts zone of ISO New England during the coldest months of the heating season, assuming sufficient availability of battery storage. If it were possible to install the described 10,000 MW of offshore wind capacity at a cost of $5 million per MW, and the 10,000 MW of solar PV capacity at a cost of $3 million per MW, the total capital expense would be approximately $80 billion. If floating-type offshore wind platforms are required, however, due to water depths greater than 180 feet, an upward revision to the wind turbine capital expense figure would become necessary.

    For a MA peak grid load of about 15,000 MW for residential and commercial heat pumps, the required nominal, 48-hour, battery storage capacity, to enable continued operation during extended cold temperature and low windspeed conditions, would be approximately 720,000 MWh.

    If utility-scale battery storage were to cost $200,000 per MWh capacity, based on NREL mid-range cost projections for the year 2030, the capital expense for battery storage would be approximately $120 billion, to cover the 48-hour storage discharge needed during a wind drought. This figure may be subject to adjustment, however, based on battery material price increases or decreases which might occur as the wind and solar industries grow. Increased production volumes may contribute to economies of scale, which might provide downward pressure on costs. Increased volumes of mining and extraction of materials for batteries, on the other hand, could trigger higher prices due to supply shortages. Lithium and cobalt commodity prices have recently increased multi-fold with corresponding upward pressure on battery storage prices.

Increased grid transmission capacity in Massachusetts would also be necessary to enable full implementation of residential and commercial heat pumps. While transmission upgrade costs will vary widely on a local basis depending on existing capacity and load characteristics, this analysis uses an average annual cost figure of $94 per kw-yr for New England, as developed in the 2021 Avoided Energy Supply Component Update report by Synapse Energy Economics for electric utilities and state regulatory agencies located in the ISO New England grid. The $94 figure represents a combination of construction and operating cost, e.g., labor, administration, insurance, and taxes. The corresponding, total combined capital and operating cost figure could have an order of magnitude of $2000 per kw of increased transmission capacity, although actual cost figures are highly dependent on specific circumstances. Using the figure of $2000 per kW of increased transmission capacity, the corresponding cost for 15000 MW of transmission upgrades in Massachusetts would be approximately $30 billion.

Increased local electricity distribution capacity would also be necessary for implementation of residential and commercial heat pumps in Massachusetts. Synapse Energy Economics has identified a wide range of accounting practices used by electric utilities in New England, with corresponding cost figures that range from *de minimis* to over $200 per kW-yr. More consistent accounting practices used in other states, such as New York, have indicated distribution upgrade costs ranging from $50 to $250 per kW-yr, representing variations in cost and difficulty of distribution network construction which occur in rural through dense urban environments. A corresponding, total combined capital and operating cost figure of $3000 per kW is used for this analysis. The corresponding cost for 15000 MW of transmission upgrades would be approximately $45 billion.

Recent capital cost analyses for residential heat pumps have centered on an approximate figure of $20,000 per onsite installation. The corresponding capital cost for installation of 2.6 million residential heat pumps in Massachusetts would be approximately $52 billion. The commercial building sector uses about 50% as much heating equipment capacity and energy consumption as the residential sector. The total capital cost for installation of residential and commercial heat pumps in Massachusetts would thus be approximately $80 billion.

The capital cost figures estimated above for offshore wind and solar PV generation capacity, battery storage, transmission, and distribution upgrades, as well as for onsite installation of residential heat pumps, for full implementation of residential and commercial heat pumps in Massachusetts, are presented in the following table.

Time Horizon	10 yrs	20 yrs	30 yrs
Wind and Solar PV Generation	$ 80 billion	$ 80 billion	$ 80 billion
Battery Storage	$ 120 billion	$ 240 billion	$ 360 billion
Transmission	$ 30 billion	$ 30 billion	$ 30 billion
Distribution	$ 44 billion	$ 44 billion	$ 44 billion
Onsite Heat Pump Installation	$ 80 billion	$ 120 billion	$ 160 billion
Total	$ 354 billion	$ 514 billion	$ 674 billion

Table 1. Summary of capital costs for full implementation of residential and commercial heat pumps in Massachusetts

The above table shows capital cost figures for three different time horizons. A service life of 30 years is used for the analysis of wind and solar PV generation, transmission and distribution systems. A service life of 10 years is used for battery storage systems, to reflect the limited lifetime of batteries used for daily charge/discharge cycles with depth of discharge (DOD) values in the range of 80 percent. Full battery replacement plus major maintenance/upgrades of charging controls and physical facilities have been presumed at the 10- and 20-year marks. Similarly, an initial service life of 10 years has been used for cold-climate heat pumps that are used for full heating season operation, with major (e.g., compressor/controls) component replacement required at the 10- and 20-year marks. The significant impact on long-term, total capital costs by short-lived equipment components can be seen in the table.

An earlier figure shows that approximately 22.2 million MWh of electricity would be generated per heating season by the described combination offshore wind plus solar PV system. A high fraction of the potential output of the dedicated wind/solar generation capacity necessary for winter heating would be foregone during the summer due to the high ratio of winter-to-summer peak load that would occur due to electrification of heating. A total of approximately 660 million MWh would be produced over the course of 30 years.

The total capital cost of the generation/transmission/distribution cost components would be $514 billion over the described 30-year time horizon. The corresponding energy supply cost for the described wind/solar generation system can be calculated as the $514 billion total capital cost divided by the 660 million MWh of generation over the same 30-year time horizon. The resulting marginal cost of infrastructure for electricity generation/transmission/distribution would thus be approximately $780 per MWh or 78 cents per kWh. Utility costs for administration, operations, taxes, etc., would be additional.

The use of renewable electricity for heat pump systems would achieve approximately 8 tons of CO_2 savings per year in a single-family residential unit. For the 2.7 million residential units in Massachusetts, the annual CO_2 savings would be approximately 22 million tons per year. The 30-year cumulative savings would be approximately 650 million tons of CO_2. Including the commercial building sector, which adds about 50% to the total heating load, the total 30-year savings for the combined residential and commercial building sector would be approximately 960 million tons of CO_2.

The total capital cost of $674 billion noted in the table earlier would yield a figure of approximately $700 per ton of CO_2. This dollar amount is much higher than the commonly used figure of $50 or perhaps higher as indices for the social cost of carbon. The high costs for a complete package of renewable power generation, transmission and distribution, plus onsite equipment, indicate the need for allowing more cost-effective decarbonization pathways.

There are two principles of significance to note in this analysis. First, battery storage is conspicuous as an expensive component of the total capital cost for a renewable power-heat pump concept for the residential and commercial building sectors. Battery storage systems are expensive, plus they do not have the same 30-year lifetime as for generation, transmission, and distribution equipment and thus need periodic replacement. Second, the capital cost of the renewable power-heat pump concept suffers from an overall low capacity factor due to the relatively high magnitude of peak loads compared to total annual energy consumption. Renewable fuels can therefore play a key role in maintaining acceptable cost effectiveness while achieving our environmental goals.

13) Figure 2 below shows annual CO_2e emissions for a single-family home under several different technology options that are feasible by the year 2030. The analysis was performed for Massachusetts, which has approximately 2.7 million residential units plus a broad array of commercial, industrial, and institutional buildings. Traditional fuel options include heating oil and natural gas. Renewable fuel options include biodiesel blends as well as B100 biodiesel. Heat pump options include air-to-air and air-to-water technologies. The graph also includes scenarios for the existing grid plus options for partial and full-capacity renewable power generation for operation of heat pumps. It needs to be noted that the option for full-capacity renewable power generation, which would be difficult to achieve by the year 2030, and which is shown as a long-term goal, also includes the requirement for 720,000 MWh of battery storage to be sufficient for 48 hours of operation during periods of extreme cold temperature with low offshore wind and solar output.

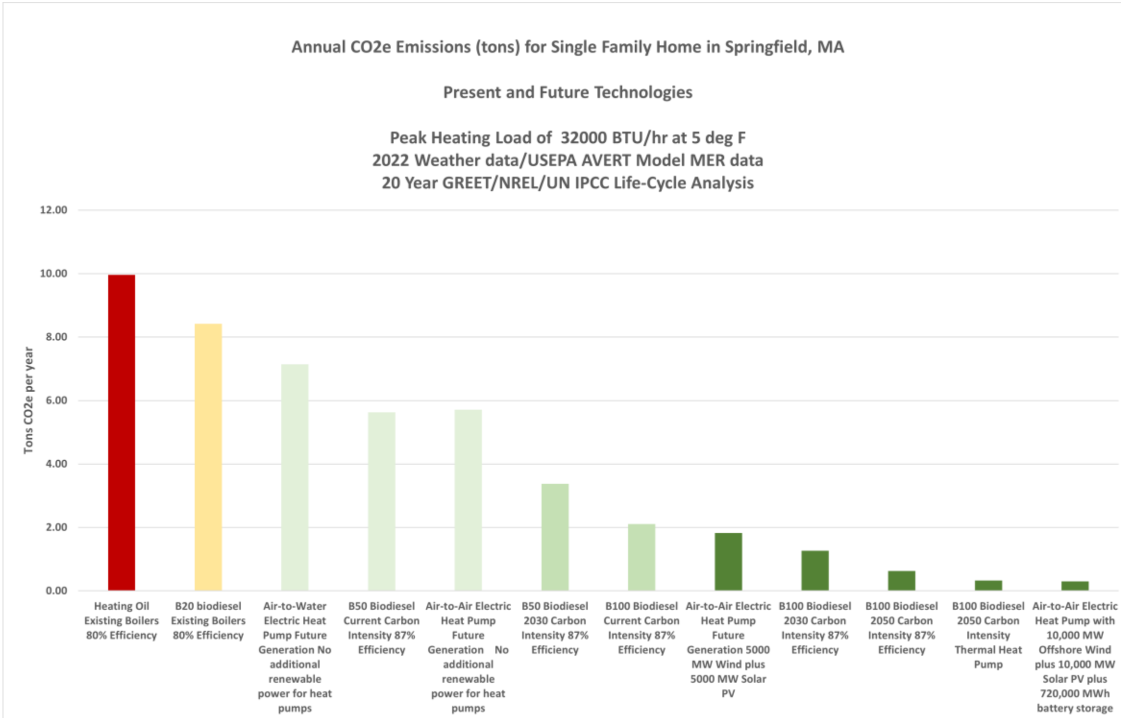


Figure 2. Annual CO2e Emissions for Single Family Homes in MA.

The individual graph bars in Figure 2 show only moderate savings, compared to traditional heating oil and natural gas-fired boilers, for air-to-water heat pump technology and basic (e.g., B20) biodiesel blends. There is then a general declining trend in CO2e emissions as biodiesel concentrations increase to the 50 and 100 percent levels, and as dedicated, combined offshore wind plus utility-scale solar capacity growth to 10,000 MW, and then 20,000 MW, nameplate capacity is accomplished. Dedicated offshore wind plus utility-scale solar capacity of 10,000 MW total would achieve CO2e savings for heat pumps of about 70 percent compared to heat pumps that use the existing grid, with an overall, seasonal carbon intensity that is approximately the same as for B100 biodiesel using an 87% efficient boiler. Dedicated renewable power capacity of 20,000 MW would provide for heat pump utilization during the peak heating periods of the winter but would require approximately 720,000 MWh of battery storage to maintain continued grid operation for up to 48 hours during low wind and solar output conditions.

The graph also shows carbon intensity values for B100 biodiesel-fired, absorption heat pumps. Such heat pumps can achieve efficiency levels of 120 to 130 percent, depending on manufacturing design, with future increases expected.

The hourly analysis performed for this evaluation shows that the carbon intensity of B50 biodiesel blend is approximately equal to air-to-water heat pumps during mild weather, but significantly lower than air-to-water heat pumps during cold weather, which is when the grid is under greatest stress. This raises the question of what energy resource strategy would be most effective during cold weather. The carbon intensity of B100 biodiesel is lower than all other existing energy options throughout nearly the entire temperature range.

14) EPA ENERGY STAR analyses should incorporate rigorous life-cycle analysis of natural gas for power generation in the evaluation of heat pumps compared with renewable fuel options. There would be considerable value in coordinating with other EPA divisions that manage the air markets database programs as well as AVERT, SMOKE and COBRA computer models used for air quality and public health analysis. The EPA SMOKE and COBRA models can evaluate the air quality and public health impacts of changes in generation emissions at local power plants in environmental justice (EJ) and Low and Moderate Income (LMI) neighborhoods. The models can forecast increases in emissions due to higher grid loads that result from electrification especially in EJ and LMI neighborhoods.

15) ENERGY STAR analyses should also incorporate the Argonne National Laboratory GREET model and UN Intergovernmental Panel on Climate Change (IPCC) guidelines, which have recognized the need to apply life-cycle analysis to **ALL** energy resources, including electricity. Accounting for both CO2 and methane emissions during production and high-pressure transmission of natural gas used for power generation, the resulting total carbon intensity of electricity increases approximately 30% above onsite-based values, with a significant downward impact on the calculated level of carbon savings achieved by electrification technologies. The results of rigorous life-cycle analysis would provide a stronger foundation for ENERGY STAR policy development.

16) ENERGY STAR analyses need to use marginal emission rates, rather than average grid mix figures, when evaluating the impact of electrification policies on grid performance. An informative article by the WattTime subsidiary of the Rocky Mountain Institute, explaining the merits of marginal emission rate analysis, is attached as an appendix to this document. Marginal emission rates more accurately account for cause-and-effect changes, including the increased use of fossil generation when intentional grid load increases, due to electrification, outpace the growth of renewable power generation capacity. The use of average grid mix figures will most often seriously underestimate the environmental cost of increased grid loads, will silently ascribe higher carbon intensities to non-thermal electricity uses, and can also lead to double counting of the benefits of renewable power generation.

17) When marginal emission rates and life-cycle analysis are used properly in the analysis of renewable thermal energy options, the findings include the conclusions that B50 biodiesel blends will generally achieve the same carbon savings as next generation, cold-climate heat pumps, which achieve 25% higher COP values than existing heat pump technology, when using the existing grid. Further, B100 biodiesel fuel will achieve lower carbon intensity than heat pumps until at least 25,000 MW nameplate capacity of wind and solar has become operational in New England, above and beyond the renewable generation capacity that would be necessary to serve existing grid loads. Biodiesel offers a highly effective, parallel pathway for achieving deep carbon savings and a sustainable energy future.

18) A recent study by Trinity Consultants (https://www.biodiesel.org/docs/default-source/trinity-study/trinity-v2-final-report-.pdf?sfvrsn=5d3a35c3_15) conducted on 15 high-risk air quality communities, including Boston, found that switching to biodiesel results in substantial health benefits. Specifically, the benefits include decreased cancer risk, fewer premature deaths, reduced asthma attacks and fewer lost workdays. B100 can achieve these benefits by reducing pollution in applications among the hardest to decarbonize – heavy-duty transportation and residential heating.

19) Recent reports have shown a wide variation in carbon intensity for electricity throughout the heating season. There is general recognition by policymakers that increased carbon intensity values occur during cold weather, due to higher grid system loads with operation of lower efficiency generation units. But higher carbon intensities also occur during morning and evening peak periods, due to efficiency penalties of turbine startup and ramping of power output to meet rapid swings in grid load. Variations of grid carbon intensity by a factor of two or more can frequently occur at the same outdoor temperature, due to short duration, peak grid loads. This then leads to the need for web-enabled heat pump control systems that favor the synchronization of operation to periods of low, grid carbon intensity. ENERGY STAR analyses should recognize that we need to avoid heat pump operation during periods of high grid carbon intensity, when little or no carbon savings are achieved compared to traditional fossil fuel, and yet, substantial wholesale power cost increases occur for grid operation.

20) Recent field-testing studies in New England have revealed a problem of heat pump underutilization by homeowners during the winter. Many homeowners are apparently purchasing heat pumps for primarily air-conditioning purposes, since state and utility incentives typically make the net cost of a heat pump cheaper than air conditioning-only models. ENERGY STAR policymakers need to consider the judiciousness and equity of limiting program eligibility to technologies which do not yet have a proven track record of effective utilization.

21) The planned capacity of offshore wind projects proposed off the New England and Long Island coast would only eliminate the need for fossil-based power generation to meet our present grid loads on a handful of days during the year. Any incremental loads such as heat pumps and electric vehicles over the next ten years will simply continue to increase fossil generation loads and push back the day when renewable power generation reaches the margin of electric supply.

    The offshore wind projects planned for the Martha's Vineyard coastal area are jockeying for limited availability of transmission interconnection at the West Barnstable substation, Canal Electric Station and just a few other prospective grid injection points. Recent ISO New England Planning Advisory Committee deliberations have been consumed by technical challenges, including voltage/frequency stability problems, to integrating offshore wind into the southeast Massachusetts grid.

    Even if transmission limitations are resolved, the wind projects planned for the next 10 years, even if fully developed, will be insufficient to eliminate fossil generation, except during a very few hours. Thus, again, any intentional grid load additions for heat pumps or electric vehicles will have to be met with fossil generation. ENERGY STAR analyses should consider that electricity used for heat pumps in the foreseeable future will come from fuel-fired generation facilities rather than solar PV or wind.

22) The doubling of grid loads to accommodate heat pumps will cause significant upward pressure on the cost of wholesale power. Market clearing prices for wholesale power in the ISO New England and New York ISO control regions are set by the last generation plant to clear hourly Day Ahead or Real-time auctions, with the last plant, by definition, having the highest bid price. The corresponding wholesale power rate in $/MWh, attributed to the generation plant at the margin, is then paid to all operating generators within the control region. This means that the total cost of power to customers is set by the most expensive generators to clear the auctions,

which means higher electricity costs for everybody when the New England and New York grids are burdened with heat pump loads.

23) Most thermal loads occur during morning and evening peak periods or during cold weather when peaking operation becomes dominant for power generation at the margin. Under peak load conditions, the direct combustion of biodiesel blends can achieve lower levels of NOx emissions than peaking generators, which historically have demonstrated extremely high levels of emissions during startup. Additionally, the low-level area source of NOx associated with the direct combustion of biodiesel blends would then be concentrated, if heat pumps were to be used, into a major point source that falls under US EPA Title 5 Clean Air Act emissions standards. Possible environmental justice concerns would result due to high local emissions in LMI and EJ neighborhoods adjacent to power plants.

ADDITIONAL TECHNICAL BACKGROUND

EXPANDING THE AVAILABILITY OF BIODIESEL GENERATES LONG-TERM CLIMATE BENEFITS

As stated in the stark UN IPCC 6th assessment released on August 12th, 2021, "It is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred." Furthermore, the report states, "From a physical science perspective, limiting human-induced global warming to a specific level requires limiting cumulative CO2 emissions, reaching at least net zero CO2 emissions, along with strong reductions in other greenhouse gas emissions."

Simply put, reducing carbon emissions now is more valuable than reducing the same quantity of emissions later. This is because earlier reductions limit the long-term climate impact caused by the accumulation of greenhouse gases. This significant and often overlooked principle is frequently absent from policy discussions, which, for example treat a reduction of CO_2 in 2023 with the same weight as a reduction in 2050. This is simply not accurate and skews the market to seek low-readiness technology options which may not be deployed for years or decades, if ever at all.

Recently, The State University of New York (SUNY-ESF) published research highlighting the value of early GHG reduction, limiting the cumulative heating impact of carbon emissions. This study compared the cumulative emissions reductions and associated societal value of using biodiesel today compared to waiting for a future, potentially lower carbon solution to be deployed later. These results demonstrated that when a technology with a low life-cycle GHG emission profile was deployed even five years later, it would generate less reduction in GHG emissions than a low life-cycle GHG technology deployed sooner. More simply, carbon reductions now are more important than carbon reductions later. The benefits accumulate, much like compound interest on a savings account.

While the current study was focused on transportation, it is likely to be expanded to cover home heating, including the use of biodiesel, electric heat pumps and natural gas. This work, which considered the timing of carbon reductions from a financial and economic standpoint has been echoed from a physical sciences standpoint in different journals by other researchers at UC Davis who have studied what they call, the 'Time Adjusted Warming Potential'.

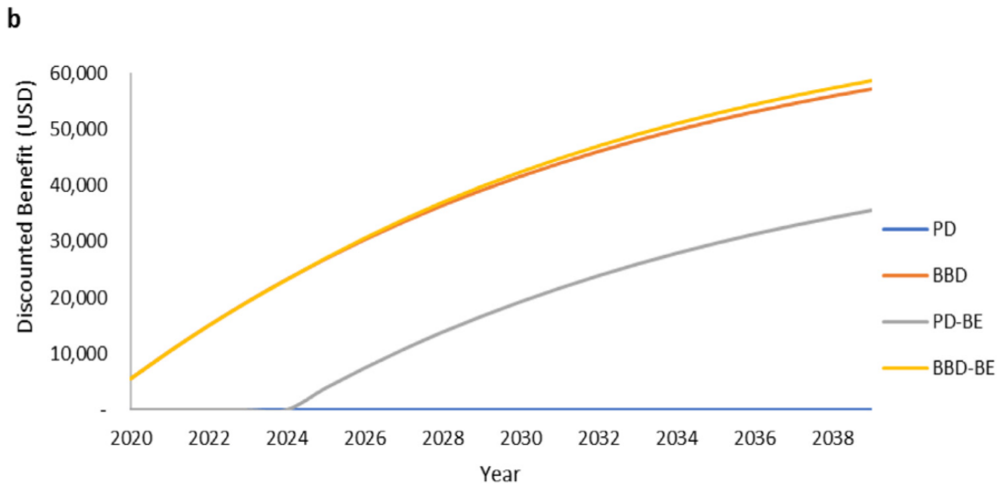


Figure 1. Time-based Sensitivity of Cumulative CO2 Savings for Biodiesel (orange) vs. Electrification Technologies (gray)

HEALTH BENEFITS OF BIODIESEL - BEYOND GREENHOUSE GAS SAVINGS

The increased use of biodiesel in home heating oil applications not only has significant GHG benefits as noted by researchers across the nation but replacing diesel with biodiesel also results in a dramatic reduction in co-pollutants, sometimes called criteria pollution or tailpipe emissions. In particular, biodiesel can reduce diesel particulate matter emissions in home heating oil applications by 86%. These dramatic reductions can lead to significant health benefits in the form of reduced asthma attacks, avoided work loss days, and reduced cancer risk.

Often, the modeling framework to assess the health benefits from a reduction in criteria pollution employs a top-down method, estimating a reduction in specific criteria pollutant like PM, and assuming there is a normal distribution of these benefits among citizens. While this is appropriate to generally characterize the benefits of a policy designed to reduce these harmful emissions, it often fails to help decision makers and citizens truly understand how the reduction in these emissions will affect their local community and in what way.

To better characterize the health benefits biodiesel can generate in local communities who switch from diesel, Clean Fuels Alliance America commissioned a study (https://www.biodiesel.org/docs/default-source/trinity-study/trinity-v2-final-report-.pdf?sfvrsn=5d3a35c3_15) by Trinity Consultants, a globally renowned air quality modeling firm, who specializes in air dispersion modeling. Their work, which is published online, characterizes the benefits of these fuels much more granularly, allowing decision makers to understand where the benefits of reduced particulate matter, improved health outcomes, would occur and to whom. The results demonstrate that the use of B100 as a heating oil replacement reduces carcinogenic, diesel particulate matter emissions by 86%.

REFERENCES USED IN PREPARATION OF TECHNICAL NOTES AND COMMENTS

As the first step in preparation of these technical notes and comments, I compiled and reviewed several key testing reports that have been published over the past six years relating to actual field performance of cold-climate heat pumps. The reports are listed below and represent the most frequently cited literature that has been published on field performance of cold-climate heat pumps.

1) Commonwealth Edison Company (2020). Cold Climate Ductless Heat Pump Pilot Executive Summary. Chicago, IL. https://www.comedemergingtech.com/images/documents/ComEd-Emerging-Technologies-Cold-Climate-Ductless-Heat-Pump.pdf

2) ISO New England (2020), Final 2020 Heating Electrification Forecast. Holyoke, MA. https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_heat_elec_forecast.pdf

3) The Levy Partnership/NYSERDA (2019). Downstate (NY) Air Source Heat Pump Demonstration. Albany, NY. https://static1.squarespace.com/static/5a5518914c0dbf4226cd5a8e/t/5d963d39f515f87c7bafe3ff/1570127329734/TLP+ASHP+Demo+Presentation+9.26.19.pdf

4) slipstream/Michigan Electric Cooperative Association (2019). Dual Fuel Air-Source Heat Pump Monitoring Report. Grand Rapids, MI. https://slipstreaminc.org/sites/default/files/documents/research/dual-fuel-air-source-heat-pump-pilot.pdf

5) Center for Energy and Environment (2018). Case Study 1 – Field Test of Cold Climate Air Source Heat Pumps. St. Paul, MN. https://www.mncee.org/MNCEE/media/PDFs/ccashp-Study-1-Duplex.pdf

6) Center for Energy and Environment (2018). Case Study 2 – Field Test of Cold Climate Air Source Heat Pumps. Minneapolis, MN. https://www.mncee.org/MNCEE/media/PDFs/ccashp-Study-2-MPLS.pdf

7) Center for Energy and Environment/Minnesota Department of Commerce, Division of Energy Resources (2017). Cold Climate Air Source Heat Pump. Minneapolis, MN. https://www.mncee.org/MNCEE/media/PDFs/86417-Cold-Climate-Air-Source-Heat-Pump-(CARD-Final-Report-2018).pdf

8) The Cadmus Group/Vermont Public Service Department (2017). Evaluation of Cold Climate Heat Pumps in Vermont. Montpelier, VT. https://publicservice.vermont.gov/sites/dps/files/documents/Energy_Efficiency/Reports/Evaluation%20of%20Cold%20Climate%20Heat%20Pumps%20in%20Vermont.pdf

9) The Cadmus Group/Massachusetts and Rhode Island Electric and Gas Program Administrators (2016). Ductless Mini-Split Heat Pump Impact Evaluation. MA and RI. http://www.ripuc.ri.gov/eventsactions/docket/4755-TRM-DMSHP%20Evaluation%20Report%2012-30-2016.pdf

10) Center for Energy and Environment/American Council for an Energy-Efficient Economy/Minnesota Department of Commerce, Division of Energy Resources (2016). *Field Assessment of Cold Climate Air*

Source Heat Pumps. 2016 ACEEE Summer Study on Energy Efficiency in Buildings. https://www.aceee.org/files/proceedings/2016/data/papers/1_700.pdf

11) Steven Winter Associates, Inc./National Renewable Energy Laboratory (2015). Field Performance of inverter-Driven Heat Pumps in Cold Climates. VT and MA. https://www.nrel.gov/docs/fy15osti/63913.pdf

12) The Levy Partnership and CDH Energy Corp./NYSERDA (2014). Measured Performance of Four Passive Houses on Three Sites in New York State. Albany, NY. https://static1.squarespace.com/static/5a5518914c0dbf4226cd5a8e/t/5ab273db562fa758761512bd/1521644514205/Measured-Performance-of-three-Passive-Houses+%283%29.pdf

Additional field studies of cold-climate heat pump performance are known to be currently underway in Massachusetts and New York, but no information has been published relating to their scope or results.

Briefly, the published field-testing reports show a significant drop in actual, cold-climate heat pump performance compared to manufacturer efficiency ratings. Many of the reports showed efficiencies that were 20 to 30 percent lower than manufacturer ratings. Identified causes included excessive compressor cycling under part-load conditions, sub-optimal defrost operation, and airflow restrictions in indoor units. Some of the efficiency differences can also be attributed to manufacturer ratings that are based on weather data for USDOE Climate Zone 4, which covers much of the warmer, mid-Atlantic region.

The analyses provided in this document include, however, the expectation that cold-climate heat pumps will achieve 25% improvements in COP performance by the year 2030, in response to the USDOE Heat Pump Challenge, stricter State mandates, and general product improvements by manufacturers.

The referenced reports also include a substantial volume of data regarding the underutilization of heat pumps by homeowners during the winter. The reports discuss occupant concerns about comfort, operating cost, and system capacity during cold weather.

These technical notes are also based on resources from Argonne National Laboratory (GREET model), the National Renewable Energy Laboratory (NREL), and the United Nations Intergovernmental Panel on Climate Change (UN IPCC) 2019 guidance update on life-cycle analysis of fuels and power generation.

Evaluations of capital expenses in these technical notes are based on a number of recently published reports, including the 2021 Avoided Energy Supply Component Update report prepared by Synapse Energy Economics for electric utilities and state regulatory agencies located in the ISO New England grid. Two reports from the National Renewable Energy Laboratory (NREL) were also used, including "Cost Projections for Utility-Scale Battery Storage 2021 Update" and "2020 Cost of Wind Energy Review". A report by the Brattle Group entitled, "Marginal Cost of Service Study", prepared for Con Edison, was also used.

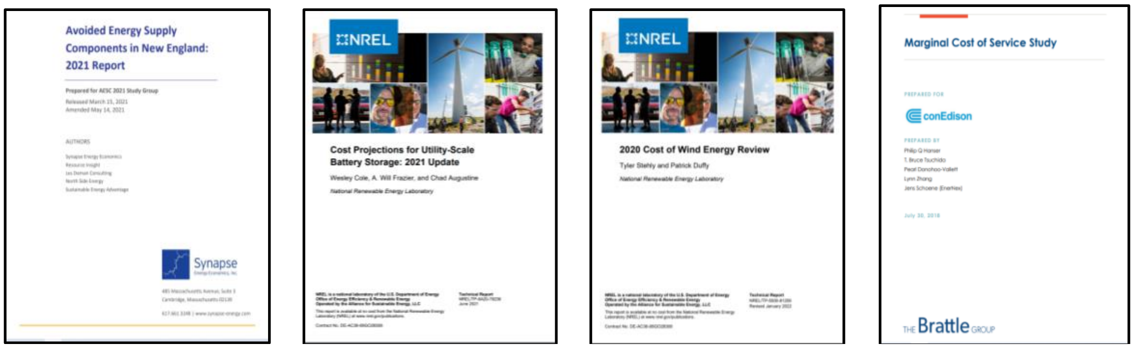


Figure 2. References Used in Capital Expense Evaluations

EVALUATION OF RESULTS FROM FIELD TESTING OF COLD-CLIMATE AIR-TO-AIR HEAT PUMPS

The efficiency of cold-climate air-to-air heat pumps in the field has been documented as 20% to 30% below current manufacturer ratings. Based on the data included in the reports listed above, I have put together a series of graphs that illustrate heat pump performance and homeowner characteristics noted regarding utilization of their heat pumps.

The first graph below shows heat pump Coefficients of Performance (COPs) vs. outdoor temperature, as derived from the field-testing studies. The graph includes average manufacturer ratings of heat pumps (red data curve) used in the various field studies listed above. The graph also shows actual field-testing results published in the listed reports. The graph shows how heat pump COPs vary with outdoor temperature. It is also possible to see the trend of actual performance falling below manufacturer ratings for most studies.

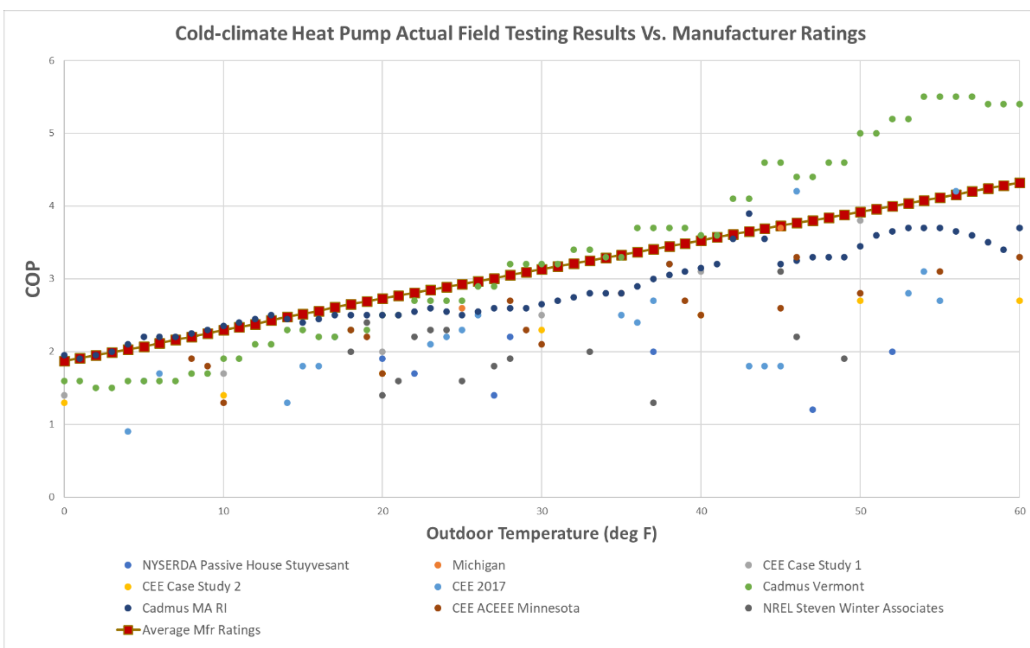


Figure 3. Cold-climate Heat Pump Actual Field-Testing Results vs. Manufacturer Ratings

Figure 4 following shows annual, cold-climate heat pump COP field data as published by the references used for these technical notes. Annual cold-climate heat pump COPs indicate much lower field efficiency than manufacturer ratings. Higher reported field efficiency by VT and MA/RI field testing was due to low utilization in colder weather, thus skewing the statistics. Power demand graphs in the cited references indicate that the drop-out rate increased as the outdoor temperature went down. As noted again, such homeowner behavior resulted in artificially high measured annual COP values since the performance data was skewed toward warmer temperatures. The remaining studies generally entailed, by design or mandate, a high utilization factor through the winter, but then lower COP values.

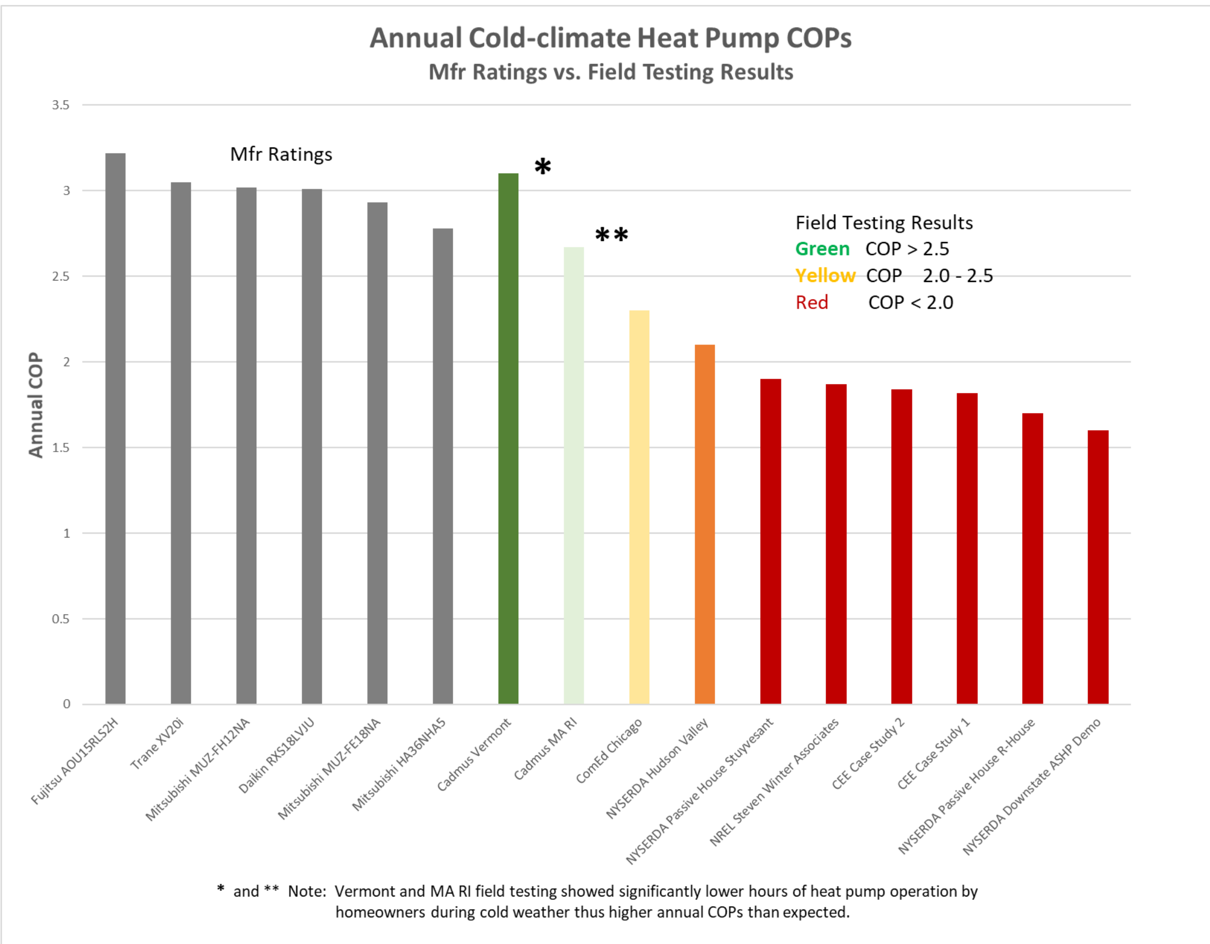


Figure 4. Annual Cold-climate Heat Pump COPs – Manufacturer Ratings vs. Field Testing Results

The manufacturer-rated seasonal COPs are generally around 3 or so, but the actual field-testing results show values in the range of about 1.6 to 2.3 (see color coding of graph bars), which translates into a loss of about 20 to 30% from the manufacturer-rated values. The resulting conclusion is that, especially if the lower COP figures are combined with the use of marginal/non-baseload carbon intensity figures for power generation (instead of average grid mix figures), plus life-cycle analysis of natural gas used for power generation, the GHG savings of cold-climate heat pumps, compared to traditional oil-fired systems, are significantly diminished compared to popular claims by electrification proponents.

USE OF MARGINAL EMISSION RATES IN EVALUATION OF ELECTRIFICATION MEASURES

A recent publication by the Rocky Mountain Institute (RMI) states that a growing number of environmental organizations, when evaluating the emissions impacts of changes to grid loads or power production, "have been mis-applying average emissions factors to estimate the impact of environmental decisions. To protect against this mistake, the correct way to measure the impact of environmental decisions is to use *marginal* emissions factors. Marginal emissions factors measure the actual environmental consequences of taking different potential actions on the power grid."

The use of average grid mix figures has unfortunately become pervasive among electrification advocates in the Northeast. Average grid mix figures result in a severe underestimation of increases in CO2 emissions that would result from implementation of electrification measures at a faster pace than construction of renewable power generation resources.

See additional details in the informative RMI document entitled, On the Importance of Marginal Emissions Factors for Policy Analysis, which is available at https://rmi.org/combating-climate-change-measuring-carbon-emissions-correctly/ and also attached as an appendix at the end of this document.

See also https://www.watttime.org/app/uploads/2019/03/Automated-Emissions-Reduction-Primer_RMI-Validation_June2017.pdf and https://www.watttime.org/marginal-emissions-methodology/ for multiple additional references on the use of marginal emission rates for energy analysis. WattTime is a new, not-for-profit organization, and subsidiary to the Rocky Mountain Institute, which collects and disseminates hourly, real-world data on grid performance to enable informed, environmentally responsible electricity choices by large customers.

USE OF LIFE-CYCLE ANALYSIS OF ENERGY RESOURCES

It is of critical importance to use life-cycle analysis for energy policymaking. Onsite-based emissions evaluations generally fail to realistically address the real-world performance of the power grid. Argonne National Laboratory has been the host administrator of the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model for many years. The GREET model is a highly respected tool for evaluating the life-cycle characteristics of energy resources. The United Nations Intergovernmental Panel on Climate Change (UN IPCC) has issued a series of updates to its comprehensive documentation relating to evaluation of energy resources.

Both GREET and IPCC provide clear guidance on the evaluation of upstream emissions of energy resources. Notably, both have recently addressed the problem of methane leakage in compounding the environmental impact of natural gas, including that used for power generation. MassDEP and MADOER energy policymakers are strongly encouraged to join the international community in recognizing and quantifying the environmental impact of methane leakage on the carbon intensity of electrification technologies.

The two major reference sources for life-cycle analysis used in the preparation of these notes, including the Argonne National Laboratory GREET 2021 model, as well as the recent United Nations Intergovernmental Panel on Climate Change (IPCC) 2019 update report on guidance for life-cycle assessment protocols, have correctly addressed the environmental characteristics of natural gas used for power generation. Both the GREET and IPCC references incorporate a methane leakage rate of approximately 0.7% of the volume of natural gas used for power generation. This accounts for methane loss during natural gas production and high-pressure transmission directly to power plants, but not through any local distribution piping.

If a 100-year timeframe is used for analysis (GHG factor for NG = 25 compared to CO2), the 0.7% methane leakage rate results in about a 9 percent increase in the carbon intensity of natural gas that reaches the power plant. If a 20-year timeframe is used, however, for analysis (GHG factor for NG = 84 compared to CO2), the 0.7% methane leakage rate results in about a 20+ percent increase in the carbon intensity of natural gas used for power generation. There is growing support, and mandate in neighboring New York, for the use of 20-year greenhouse gas analysis since that reflects the timeframe that is now perceived as necessary for addressing climate change.

Combined with the impact of an approximate 10% increase in carbon intensity resulting from direct CO2 emissions during natural gas production and high-pressure transmission, the CO2e emissions characteristic of natural gas used for power generation is approximately 30% higher than the 117 lb/MMBTU onsite emissions figure frequently used by electrification proponents, thus approximately 152 lb/MMBTU.

GREET 2021 model figures are used for other fuel-based options included in the analysis presented here. The GREET figure of 185 lb/MMBTU (20-year LCA basis) is used for natural gas in residential and commercial heating, thus reflecting the additional methane losses that are incurred in local distribution networks. The GREET figure of 223 lb/MMBTU (20-year LCA) is used for distillate heating oil. GREET 2021 figures of 29 lb/MMBTU and 73 lb/MMBTU are used respectively for biodiesel produced from waste feedstock and virgin soy oil.

National Renewable Energy Laboratory (NREL) figures are used for evaluating renewable natural gas (RNG) and wind power. Carbon intensity data for RNG are sparse in availability but indicate that RNG can have approximately the same sustainability values as has been documented for biodiesel. NREL carbon intensity figures for wind are likewise sparse.

ACCOUNTING FOR TRANSMISSION AND DISTRIBUTION LINE LOSSES IN ANALYSIS OF GRID IMPACTS OF ELECTRIFICATION

When the electrical load increases in a building, the corresponding increase in necessary power generation will be greater due to line losses that occur between the powerplant and end-use sites. The average line loss in transmission and distribution networks will usually be somewhere in the range of 8 percent here in the northeastern US. This factor must be included in analyses of electrification and renewable power generation to maintain accuracy of results. The practical consideration is that the MW amount of renewable power generation necessary to serve an increased grid load will be measurably greater than the load itself. The EPA AVERT model incorporates an automatic, built-in calculation of approximately 8% line losses. It is noted here, however, that since line losses are an I^2R issue, with losses proportional to the square of the current flow rate, thus not just a linear relationship, the incremental losses for increased grid loads during peak periods will typically be in the mid-teen percentage range, with the exact figure defined as the calculus derivative of the governing, line-loss mathematical equation. The significant policy impact of increased line losses during peak grid load conditions, due to electrification, needs to be recognized and addressed by energy policymakers.

POWER GRID ANALYSIS SOFTWARE

I used USEPA AVERT (AVoided Emissions and geneRation Tool) software to do an hourly analysis of grid impacts from residential and commercial heat pumps and to calculate required capacities of renewable power, including offshore wind, onshore wind, and utility-scale solar that would be necessary to meet expected Massachusetts heating loads using heat pumps.

See https://www.epa.gov/avert and https://www.epa.gov/avert/avert-overview-0 for more information about the AVERT program.

USEPA's AVERT software performs deep analysis using marginal emission rates, rather than average grid mix values which are incorrectly used by many energy policymakers in the northeastern United States (see article by the Rocky Mountain Institute in the Appendix). AVERT analyzes how power plants would increase/decrease their output in response to grid load changes, and what the corresponding changes in fuel use and emissions would occur. AVERT software uses the EPA national air markets database, which incorporates hourly efficiency and emissions performance data for all power plants in the United States over 25 MW capacity.

AVERT software can calculate the hourly, regional marginal impact of reductions in grid load due to energy efficiency measures, as well as increases in grid load due to intentional load-building measures such as heat pumps and electric vehicles. AVERT software also can predict the hourly, marginal impact of renewable generation by resources such as solar PV and wind power, using hourly weather data. AVERT also predicts local changes in power generation output levels by individual generating plants within a specified region.

The AVERT 4.0 software version released just recently also incorporates direct linkage with USEPA Co-Benefits Risk Assessment (COBRA) public health and Sparse Matrix Operator Kernel Emissions (SMOKE) air quality input software packages. This allows for direct modeling of public health and air quality impacts (NOx/SOx etc.) of changes in load or generation output within a regional grid. This enables the evaluation of air quality deterioration in environmental justice and LMI communities located adjacent to fossil-fired power plants as grid loads increase due to electrification.

AVERT spreadsheets are somewhat bulky, typically close to 9,000 rows in height and many columns wide, but are nevertheless relatively user-friendly. Ancillary spreadsheet analysis of grid loads, using digital, hourly (8760 hours per year) weather data and heat pump performance formulas, can be easily copied into AVERT spreadsheets to yield highly informative, power generation and emissions outputs. MassDEP and MADOER energy policymakers are encouraged to use AVERT software if they are not already doing so.

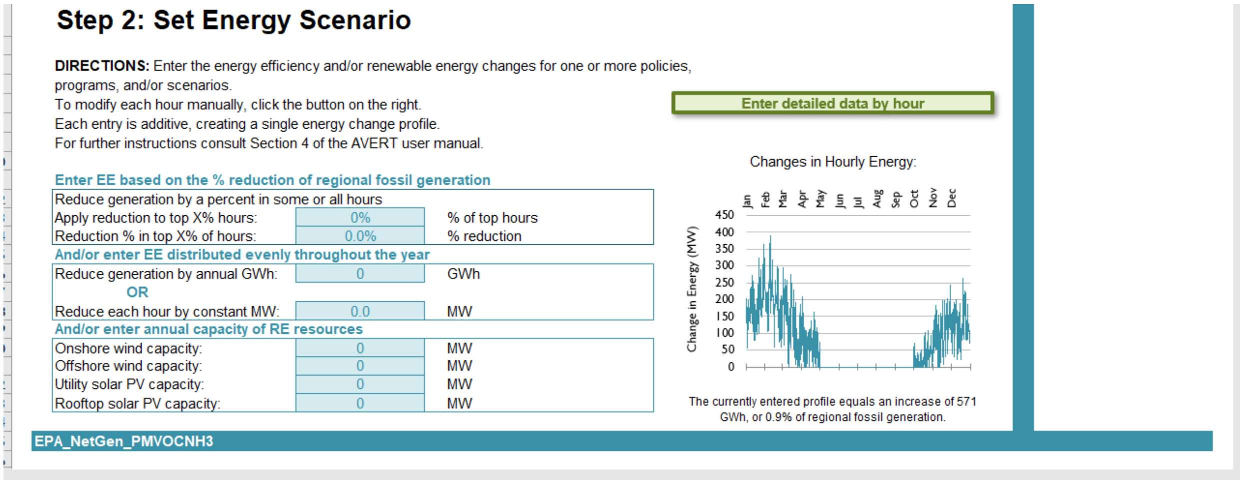


Figure 5. Example data input page for USEPA AVERT software

The screenshot shown above in Figure 5 shows an example graph of monthly grid loads that would be triggered by implementation of residential and commercial heat pumps. The AVERT program also allows for specification of renewable power capacities that might offset increasing grid loads.

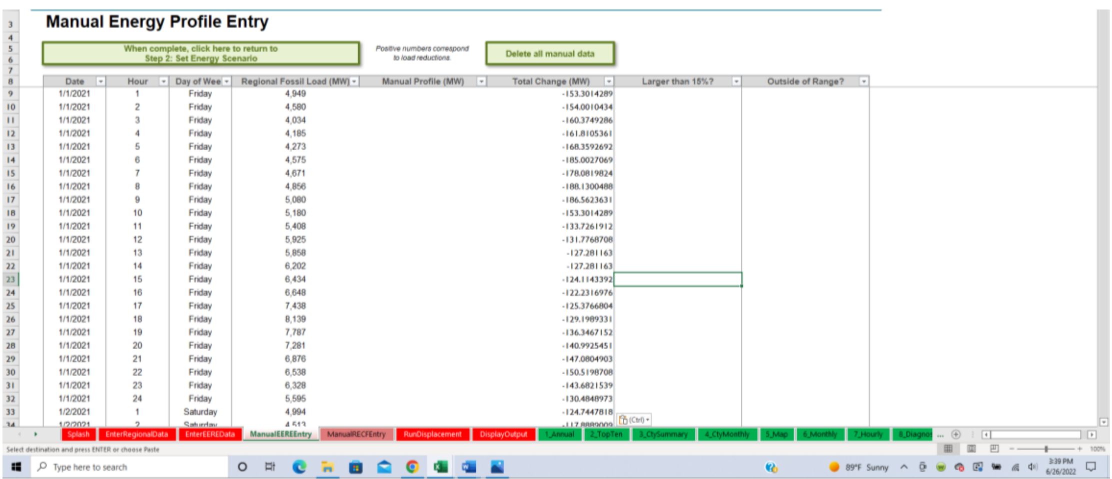


Figure 6. Example screenshot of USEPA AVERT software – manual input of grid load data

The AVERT software incorporates the manual input of MW grid load values, as shown in Figure 5 above, based on calculated heating loads, heat pump COPs, and resulting site electrical load increases. The software then calculates impacts on power plant generation and CO2 emissions, as well as other pollutants such as NOx, SOx and PM2.5 particulates.

Output: Annual Regional Results

Click here to return to Step 4: Display Outputs

	Original	Post Change	Change
Generation (MWh)	61,220,480	61,791,760	571,280
Heat Input (MMBtu)	506,770,570	511,492,860	4,722,290
Total Emissions from Fossil Generation Fleet			
SO2 (lb)	3,060,270	3,103,060	42,790
NOx (lb)	15,529,130	15,711,810	182,680
Ozone season NO_x (lb)	8,314,720	8,314,720	—
CO_2 (tons)	30,295,030	30,577,870	282,840
PM2.5 (lb)	4,845,880	4,895,770	49,890
VOCs (lb)	1,961,390	1,983,790	22,400
NH3 (lb)	2,014,380	2,040,050	25,670
AVERT-derived Emission Rates:	Average Fossil		Marginal Fossil
SO2 (lb/MWh)	0.050		0.075
NOx (lb/MWh)	0.254		0.320
Ozone season NO_x (lb/MWh)	0.279		#VALUE!
CO_2 (tons/MWh)	0.495		0.495
PM2.5 (lb/MWh)	0.079		0.087
VOCs (lb/MWh)	0.032		0.039
NH3 (lb/MWh)	0.033		0.045

Ozone season is defined as May 1 - September 30. Ozone season emissions are a subset of annual emissions.
Negative numbers indicate displaced generation and emissions.
All results are rounded to the nearest ten. A dash ("—") indicates a result greater than zero, but lower than the level of reportable significance.
This region features one or more power plants with an infrequent SO2 emissions event. SO2 emissions changes from these plants are not included in this analysis. See Section 2 of the AVERT User Manual for more information.

Figure 7. Example screenshot of AVERT summary output page showing annual generation and emissions impacts.

As shown in Figure 7 above, AVERT software produces an array of output tables and graphs ranging from hourly to annual figures. The information can then be further processed to evaluate the environmental characteristics of changes to grid loads or generation outputs.

Generation (MW) New England (NE)

Click here to return to Step 4: Display Output

									ORSPL	58054	1595	55126	55126	55317	55149	56047	54907
									UNITID	ST01	4	CT01	CT02	11	LRG2	1	1
Hour	Year	Month	Regional L	Energy Ch	Load after Energy Ch	Timestamp	Orig Gen (	Post Chan	Sum: All U	Burgess Bic	Kendall Gr	Milford Pov	Milford Pov	Fore River	Lake Road (	CPV Towa	MIT Centr
1	2019	1	2259	1,652	3910.919	01/01/2019 00:00	2,252	3,932	1680.086	1.177	15.183	31.805	30.373	48.671	13.685	16.786	-0.897
2	2019	1	2288	1,652	3939.919	01/01/2019 01:00	2,281	3,953	1671.784	1.107	12.635	32.832	32.017	50.472	9.373	13.88	-1.166
3	2019	1	1944	1,498	3441.726	01/01/2019 02:00	1,938	3,445	1506.605	0.259	27.161	39.047	30.049	14.466	23.499	42.516	-2.135
4	2019	1	1879	1,448	3327.018	01/01/2019 03:00	1,874	3,320	1445.271	-1.702	30.659	34.215	35.429	5.892	28.018	47.653	-3.517
5	2019	1	1781	1,244	3024.919	01/01/2019 04:00	1,778	3,012	1233.478	-2.359	26.666	33.931	29.331	-14.675	35.82	51.917	-4.344
6	2019	1	1917	1,059	2976.402	01/01/2019 05:00	1,912	2,972	1059.843	-2.27	24.343	26.449	24.19	-6.853	26.897	38.558	-3.049
7	2019	1	2119	840	2959.374	01/01/2019 06:00	2,110	2,957	847.649	-2.337	16.266	19.244	14.552	-4.965	18.784	23.098	-1.841
8	2019	1	2201	812	3013.08	01/01/2019 07:00	2,193	3,002	809.47	-1.802	9.568	20.659	8.062	-6.425	19.769	22.993	-1.993
9	2019	1	2471	762	3232.892	01/01/2019 08:00	2,469	3,221	751.425	-2.262	12.232	17.54	11.142	23.524	9.864	17.605	-1.835
10	2019	1	2585	696	3281.418	01/01/2019 09:00	2,587	3,269	681.7	-4.347	8.473	16.756	8.087	11.175	13.911	19.563	-3.569
11	2019	1	2535	691	3226.034	01/01/2019 10:00	2,535	3,214	678.841	-3.715	10.385	17.41	11.112	14.819	12.411	16.443	-2.711
12	2019	1	2402	696	3098.418	01/01/2019 11:00	2,398	3,088	690.057	-0.462	10.929	17.98	8.341	24.219	8.756	12.084	-0.582
13	2019	1	2422	863	3285.225	01/01/2019 12:00	2,419	3,273	854.16	-0.596	13.278	17.522	8.945	32.854	7.434	20.611	-1.208

Figure 8. Example screenshot of AVERT output page showing hourly changes to individual power plant MW generation outputs

As shown in Figure 8 above, AVERT software yields estimates of hourly changes to generation output and emissions by individual power plants. This information helps to identify what environmental justice communities might be affected by increased emissions that result from grid load growth due to electrification programs, when not sufficiently offset by new, renewable power generation.

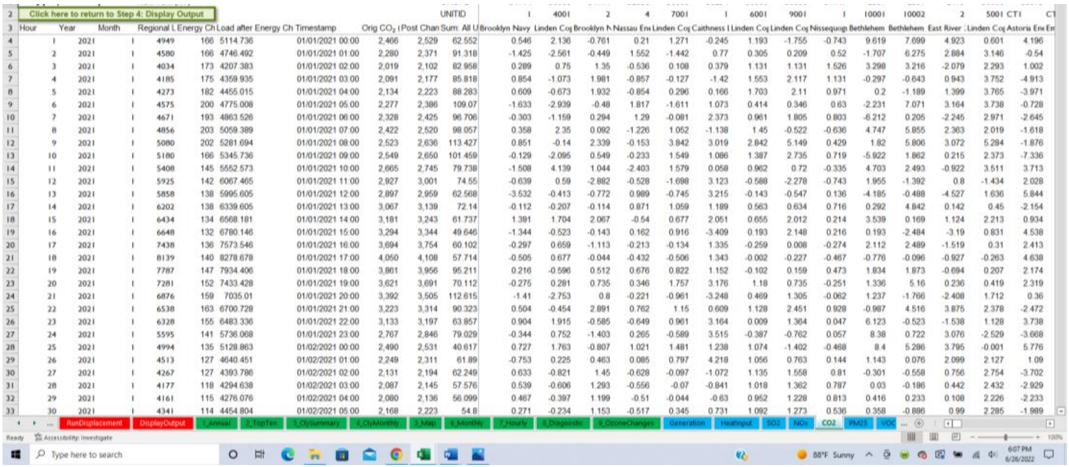


Figure 9. Example screenshot of AVERT output page showing hourly changes to individual power plant CO2 emission rates (lb/hr)

As shown in Figure 9 above, AVERT software also yields estimates of hourly changes to CO2 emissions from individual power plants. Such information is of key importance for the wholistic evaluation of environmental performance by a combined heating equipment-power grid system.

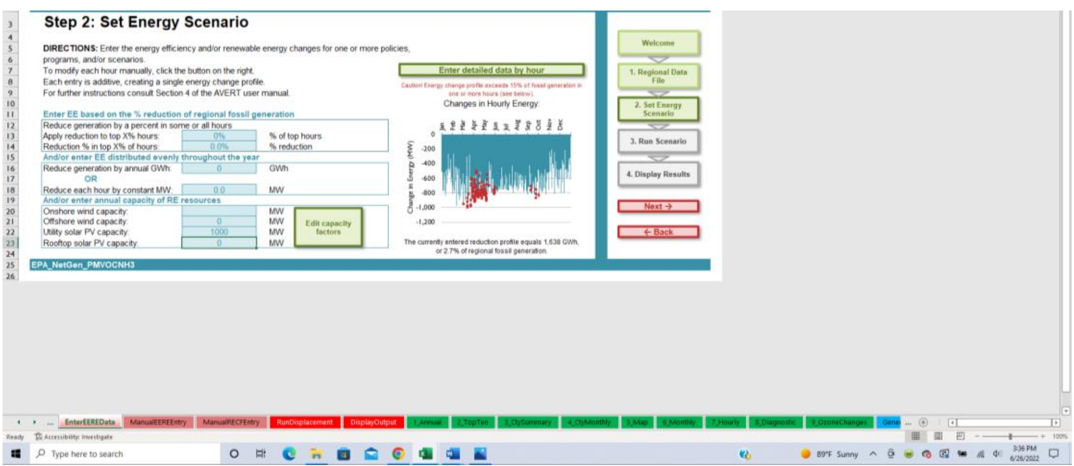
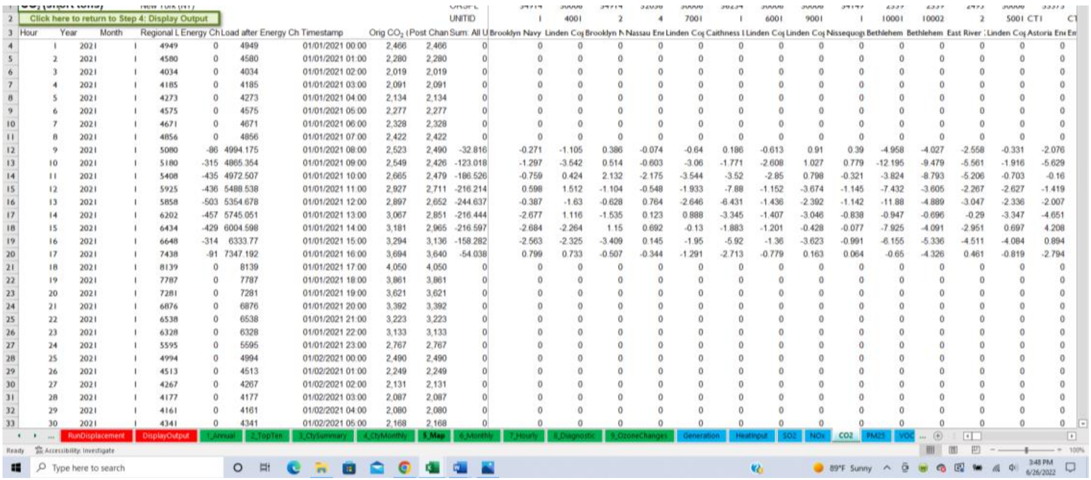


Figure 10. Example screenshot of AVERT input page showing MW quantities of renewable power generation capacity selected for analysis.

As shown in Figure 10 above, AVERT software also allows for the specification of amounts of wind and solar generation resources. The software then yields an hourly output table for the entire year, which can then be combined with grid load data to determine whether sufficient renewable power has been generated to meet the demand of electrification technologies, and if not, the quantity of fuel-based generation that must still be operated.



2	Click here to return to Step 4: Display Output									UNITID	1	4001	2	4	7001	1	6001	9001	1	10001	10002	2	5001	CT1	CT
3	Hour	Year	Month	Regional L	Energy Ch	Load after Energy Ch	Timestamp	Orig CO_2 (	Post Chan	Sum: All U	Brooklyn Navy	Linden Co	Brooklyn N	Nassau En	Linden Co	Caithness I	Linden Co	Linden Co	Nissequog	Bethlehem	Bethlehem	East River	Linden Co	Astoria En	Em
4	1	2021	1	4949	0	4949	01/01/2021 00:00	2,466	2,466	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	2	2021	1	4580	0	4580	01/01/2021 01:00	2,280	2,280	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	3	2021	1	4034	0	4034	01/01/2021 02:00	2,019	2,019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
7	4	2021	1	4185	0	4185	01/01/2021 03:00	2,091	2,091	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8	5	2021	1	4273	0	4273	01/01/2021 04:00	2,134	2,134	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9	6	2021	1	4575	0	4575	01/01/2021 05:00	2,277	2,277	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10	7	2021	1	4671	0	4671	01/01/2021 06:00	2,328	2,328	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
11	8	2021	1	4856	0	4856	01/01/2021 07:00	2,422	2,422	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
12	9	2021	1	5080	-86	4994.175	01/01/2021 08:00	2,523	2,490	-32.816	-0.271	-1.105	0.386	-0.074	-0.64	0.186	-0.613	0.91	0.39	-4.958	-4.027	-2.558	-0.331	-2.076	
13	10	2021	1	5180	-315	4865.354	01/01/2021 09:00	2,549	2,426	-123.018	-1.297	-3.542	0.514	-0.603	-3.06	-1.771	-2.608	1.027	0.779	-12.195	-9.479	-5.561	-1.916	-5.629	
14	11	2021	1	5408	-435	4972.507	01/01/2021 10:00	2,665	2,479	-186.526	-0.759	0.424	2.132	-2.175	-3.544	-3.52	-2.85	0.798	-0.321	-3.824	-8.793	-5.206	-0.703	-0.16	
15	12	2021	1	5925	-436	5488.538	01/01/2021 11:00	2,927	2,711	-216.214	0.598	1.512	-1.104	-0.548	-1.933	-7.88	-1.152	-3.674	-1.145	-7.432	-3.605	-2.267	-2.627	-1.419	
16	13	2021	1	5858	-503	5354.678	01/01/2021 12:00	2,897	2,652	-244.637	-0.387	-1.63	-0.628	0.764	-2.646	-6.431	-1.436	-2.392	-1.142	-11.88	-4.889	-3.047	-2.336	-2.007	
17	14	2021	1	6202	-457	5745.051	01/01/2021 13:00	3,067	2,851	-216.444	-2.677	1.116	-1.535	0.123	0.888	-3.345	-1.407	-3.046	-0.838	-0.947	-0.696	-0.29	-3.347	-4.651	
18	15	2021	1	6434	-429	6004.598	01/01/2021 14:00	3,181	2,965	-216.597	-2.684	-2.264	1.15	0.692	-0.13	-1.883	-1.201	-0.428	-0.077	-7.925	-4.091	-2.951	0.697	4.208	
19	16	2021	1	6648	-314	6333.77	01/01/2021 15:00	3,294	3,136	-158.282	-2.563	-2.325	-3.409	0.145	-1.95	-5.92	-1.36	-3.623	-0.991	-6.155	-5.336	-4.511	-4.084	0.894	
20	17	2021	1	7438	-91	7347.192	01/01/2021 16:00	3,694	3,640	-54.038	0.799	0.733	-0.507	-0.344	-1.291	-2.713	-0.779	0.163	0.064	-0.65	-4.326	0.461	-0.819	-2.794	
21	18	2021	1	8139	0	8139	01/01/2021 17:00	4,050	4,050	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
22	19	2021	1	7787	0	7787	01/01/2021 18:00	3,861	3,861	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
23	20	2021	1	7281	0	7281	01/01/2021 19:00	3,621	3,621	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
24	21	2021	1	6876	0	6876	01/01/2021 20:00	3,392	3,392	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
25	22	2021	1	6538	0	6538	01/01/2021 21:00	3,223	3,223	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
26	23	2021	1	6328	0	6328	01/01/2021 22:00	3,133	3,133	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
27	24	2021	1	5595	0	5595	01/01/2021 23:00	2,767	2,767	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
28	25	2021	1	4994	0	4994	01/02/2021 00:00	2,490	2,490	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
29	26	2021	1	4513	0	4513	01/02/2021 01:00	2,249	2,249	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
30	27	2021	1	4267	0	4267	01/02/2021 02:00	2,131	2,131	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
31	28	2021	1	4177	0	4177	01/02/2021 03:00	2,087	2,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
32	29	2021	1	4161	0	4161	01/02/2021 04:00	2,080	2,080	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
33	30	2021	1	4341	0	4341	01/02/2021 05:00	2,168	2,168	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Figure 11. Example screenshot of AVERT output page showing hourly values of solar power output plus impact on individual power plants.

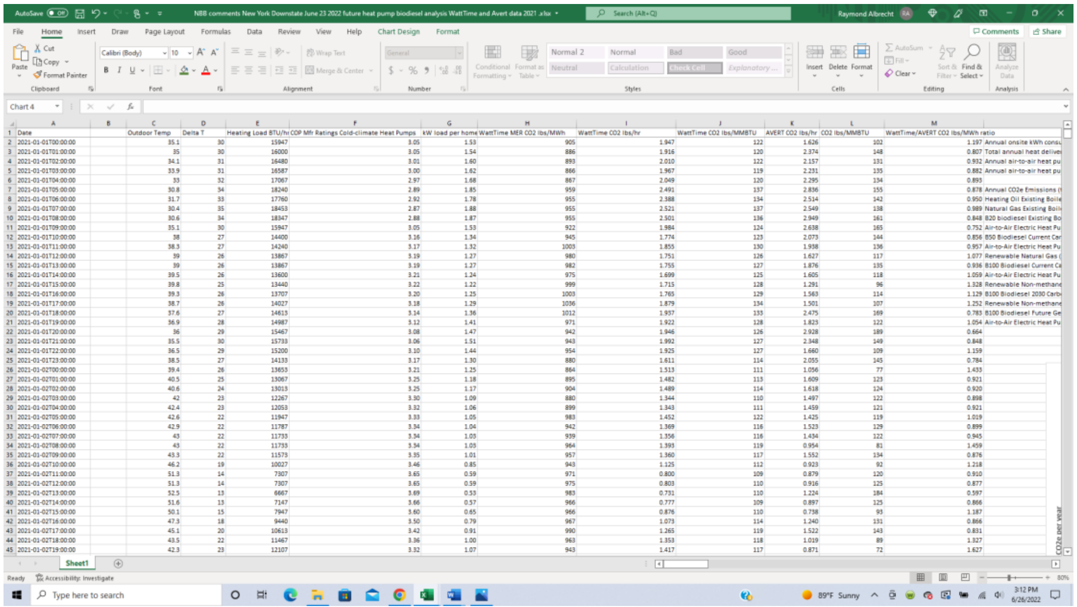
As shown in Figure 11 above, AVERT software calculates the hourly production of wind and solar power systems based on a typical year of weather data. The software then allocates reductions in generation output to individual power plants. The output data can then be combined with heating and grid load data to determine how much fuel-fired power generation might still be necessary if sufficient renewable power generation capacity has yet to be constructed.

METHODOLOGY FOR HOURLY EVALUATION OF COMBINED HEAT PUMP PERFORMANCE AND ISO NEW ENGLAND GRID CARBON INTENSITY FOR RESIDENTIAL AND COMMERCIAL HEATING

These technical notes are based on an hourly, coincidental temporal analysis of heating loads and power grid performance. Digital weather data from Visual Crossing.com for Springfield, MA was used to model hourly heating loads in a representative single-family residential unit that would have a peak heating load of 32,000 Btu/hr at an outdoor temperature of 5 deg F. The described heating load formula is intended to be broadly representative for residential buildings located in New England.

Temperature delta T values are determined using a base of 65 deg F as is customary for heating degree day analysis. Carbon intensities for common fuels including heating oil, natural gas, biodiesel and renewable natural gas are derived from the GREET 2021 model, as described earlier in this document. Heat pump COPs vs. outdoor temperature are determined through a formula based on the field test results included in the references described earlier.

Figure 12 below shows a screenshot of an Excel table that was created to perform the described hourly analysis of heating loads, grid performance, fuel/electricity input options, carbon intensities and resulting CO2 emission rates. The table includes input and output figures for the approximately 5000 hours that occur during the October through April heating season.



Date	Outdoor Temp	Delta T	Heating Load BTU/hr	COP Mfr Ratings Cold-climate Heat Pumps	kW load per home	WattTime MER CO2 lbs/MWh	WattTime CO2 lbs/hr	WattTime CO2 lbs/MMBTU	AVERT CO2 lbs/hr	CO2 lbs/MMBTU	WattTime/AVERT CO2 lbs/MWh ratio	
2021-01-01T00:00:00	35.1	30	15947	3.05	1.53	905	1.947	122	1.626	102	1.197	Annual onsite kWh consu
2021-01-01T01:00:00	35	30	16000	3.05	1.54	886	1.916	120	2.374	148	0.807	Total annual heat delive
2021-01-01T02:00:00	34.1	31	16480	3.01	1.60	893	2.010	122	2.157	131	0.932	Annual air-to-air heat pu
2021-01-01T03:00:00	33.9	31	16587	3.00	1.62	866	1.967	119	2.231	135	0.882	Annual air-to-air heat pu
2021-01-01T04:00:00	33	32	17067	2.97	1.68	867	2.049	120	2.295	134	0.893	
2021-01-01T05:00:00	30.8	34	18240	2.89	1.85	959	2.491	137	2.836	155	0.878	Annual CO2e Emissions (
2021-01-01T06:00:00	31.7	33	17760	2.92	1.78	955	2.388	134	2.514	142	0.950	Heating Oil Existing Boile
2021-01-01T07:00:00	30.4	35	18453	2.87	1.88	955	2.521	137	2.549	138	0.989	Natural Gas Existing Boil
2021-01-01T08:00:00	30.6	34	18347	2.88	1.87	955	2.501	136	2.949	161	0.848	B20 biodiesel Existing Bo
2021-01-01T09:00:00	35.1	30	15947	3.05	1.53	922	1.984	124	2.638	165	0.752	Air-to-Air Electric Heat Pu
2021-01-01T10:00:00	38	27	14400	3.16	1.34	945	1.774	123	2.073	144	0.856	B50 Biodiesel Current Car
2021-01-01T11:00:00	38.3	27	14240	3.17	1.32	1003	1.855	130	1.938	136	0.957	Air-to-Air Electric Heat Pu
2021-01-01T12:00:00	39	26	13867	3.19	1.27	980	1.751	126	1.627	117	1.077	Renewable Natural Gas (
2021-01-01T13:00:00	39	26	13867	3.19	1.27	982	1.755	127	1.876	135	0.936	B100 Biodiesel Current Ca
2021-01-01T14:00:00	39.5	26	13600	3.21	1.24	975	1.699	125	1.605	118	1.059	Air-to-Air Electric Heat Pu
2021-01-01T15:00:00	39.8	25	13440	3.22	1.22	999	1.715	128	1.291	96	1.328	Renewable Non-methane
2021-01-01T16:00:00	39.3	26	13707	3.20	1.25	1003	1.765	129	1.563	114	1.129	B100 Biodiesel 2030 Carb
2021-01-01T17:00:00	38.7	26	14027	3.18	1.29	1036	1.879	134	1.501	107	1.252	Renewable Non-methane
2021-01-01T18:00:00	37.6	27	14613	3.14	1.36	1012	1.937	133	2.475	169	0.783	B100 Biodiesel Future Ge
2021-01-01T19:00:00	36.9	28	14987	3.12	1.41	971	1.922	128	1.823	122	1.054	Air-to-Air Electric Heat Pu
2021-01-01T20:00:00	36	29	15467	3.08	1.47	942	1.946	126	2.928	189	0.664	
2021-01-01T21:00:00	35.5	30	15733	3.06	1.51	943	1.992	127	2.348	149	0.848	
2021-01-01T22:00:00	36.5	29	15200	3.10	1.44	954	1.925	127	1.660	109	1.159	
2021-01-01T23:00:00	38.5	27	14133	3.17	1.30	880	1.611	114	2.055	145	0.784	
2021-01-02T00:00:00	39.4	26	13653	3.21	1.25	864	1.513	111	1.056	77	1.433	
2021-01-02T01:00:00	40.5	25	13067	3.25	1.18	895	1.482	113	1.609	123	0.921	
2021-01-02T02:00:00	40.6	24	13013	3.25	1.17	904	1.489	114	1.618	124	0.920	
2021-01-02T03:00:00	42	23	12267	3.30	1.09	880	1.344	110	1.497	122	0.898	
2021-01-02T04:00:00	42.4	23	12053	3.32	1.06	899	1.343	111	1.459	121	0.921	
2021-01-02T05:00:00	42.6	22	11947	3.33	1.05	983	1.452	122	1.425	119	1.019	
2021-01-02T06:00:00	42.9	22	11787	3.34	1.04	942	1.369	116	1.523	129	0.899	
2021-01-02T07:00:00	43	22	11733	3.34	1.03	939	1.356	116	1.434	122	0.945	
2021-01-02T08:00:00	43	22	11733	3.34	1.03	964	1.393	119	0.954	81	1.459	
2021-01-02T09:00:00	43.3	22	11573	3.35	1.01	957	1.360	117	1.552	134	0.876	
2021-01-02T10:00:00	46.2	19	10027	3.46	0.85	943	1.125	112	0.923	92	1.218	
2021-01-02T11:00:00	51.3	14	7307	3.65	0.59	971	0.800	109	0.879	120	0.910	
2021-01-02T12:00:00	51.3	14	7307	3.65	0.59	975	0.803	110	0.916	125	0.877	
2021-01-02T13:00:00	52.5	13	6667	3.69	0.53	983	0.731	110	1.224	184	0.597	
2021-01-02T14:00:00	51.6	13	7147	3.66	0.57	966	0.777	109	0.897	125	0.866	
2021-01-02T15:00:00	50.1	15	7947	3.60	0.65	966	0.876	110	0.738	93	1.187	
2021-01-02T16:00:00	47.3	18	9440	3.50	0.79	967	1.073	114	1.240	131	0.866	
2021-01-02T17:00:00	45.1	20	10613	3.42	0.91	990	1.265	119	1.522	143	0.831	
2021-01-02T18:00:00	43.5	22	11467	3.36	1.00	963	1.353	118	1.019	89	1.327	
2021-01-02T19:00:00	42.3	23	12107	3.32	1.07	943	1.417	117	0.871	72	1.627	

Figure 12. Screenshot of hourly heating system and power grid performance Excel analysis table.

After hourly heating loads and corresponding grid load increases have been determined, interim data from the Excel table are copied to the manual data input page of the AVERT software. The AVERT software then calculates generation and CO2 emissions changes, which are then transferred back to the Excel table to enable completion of the combined analysis.

WattTime hourly Marginal Emission Rates (MERs) in lbs CO2 per MWh for New England were also used in the Excel table to evaluate the grid impact of heat pumps. WattTime data does not provide for analysis of impacts on individual power plants but provides for a higher resolution analysis of geographical variations in carbon intensity between ISO New England zones.

ANALYTICAL RESULTS AND TECHNICAL COMMENTS

Annual CO2e Emissions for Single-family Homes in Massachusetts

Figure 13 below shows annual CO2e emissions for a single-family home in Massachusetts under several different technology options that are feasible by the year 2030. Massachusetts has approximately 2.6 million residential units plus a broad array of commercial, industrial, and institutional buildings. Traditional fuel options include heating oil and natural gas. Renewable fuel options include biodiesel blends as well as B100 biodiesel. Heat pump options include current air-to-air technology plus improved, future generation technology. The graph also includes scenarios for the existing grid plus options for partial and full-capacity renewable power generation for operation of heat pumps. It needs to be noted that the option for full-capacity renewable power generation, which would be difficult to achieve by the year 2030, and which is shown as a long-term goal, also includes the requirement for 720,000 MWh of battery storage to be sufficient for 48 hours of operation during periods of extreme cold temperature with low offshore wind and solar output.

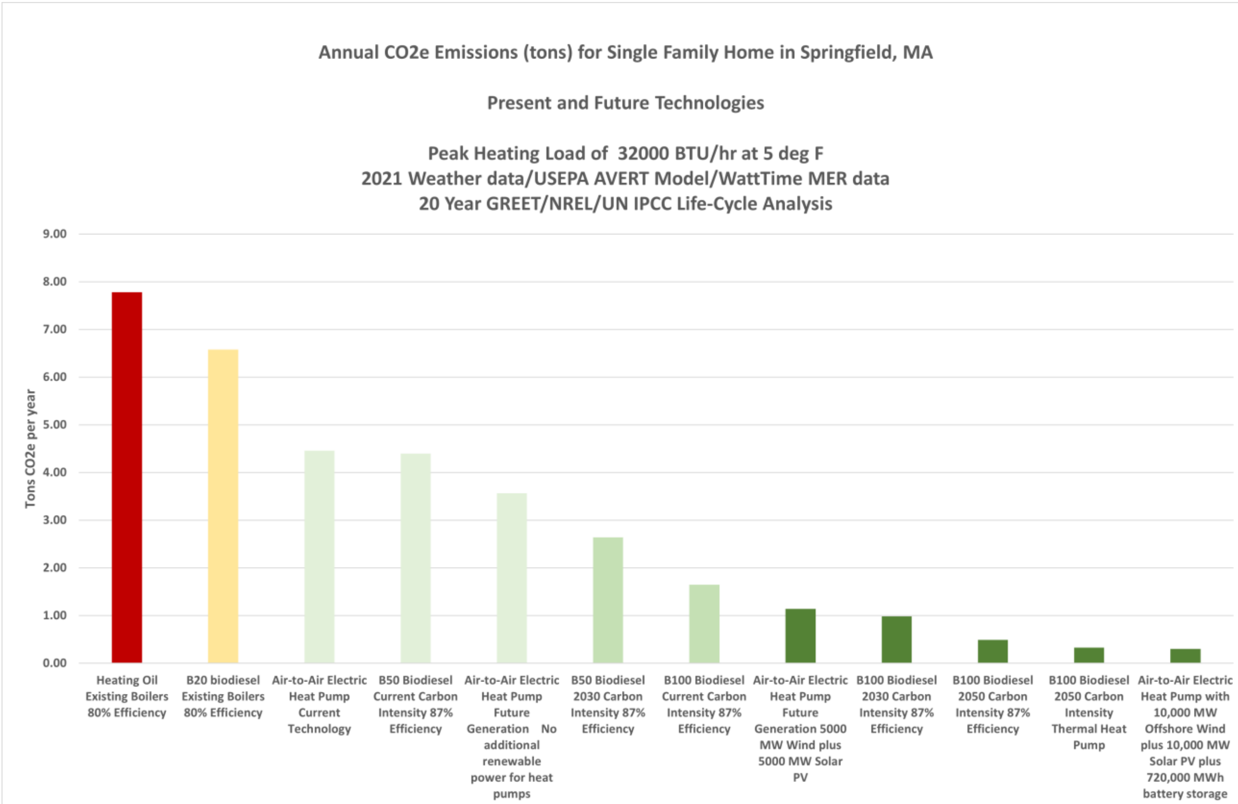


Figure 13. Annual CO2e Emissions for Single Family Homes in MA.

The individual graph bars in Figure 13 show similar, moderate savings, compared to traditional heating oil and natural gas-fired boilers, for current heat pump technology and basic (e.g., B20) biodiesel blends. There is then a general declining trend in CO2e emissions as biodiesel concentrations increase to the 50 and 100 percent levels, and as dedicated, combined offshore wind plus utility-scale solar capacity growth to 10,000 MW, and then 20,000 MW, nameplate capacity is accomplished. Dedicated offshore wind plus utility-scale solar capacity of 10,000 MW total would achieve CO2e savings for heat pumps of about 70 percent compared to heat pumps that use the existing grid, with an overall, seasonal carbon intensity that is approximately the same as for B100 biodiesel using an 87% efficient boiler. Dedicated renewable power capacity of 20,000 MW would provide for heat pump utilization during the peak heating periods of the winter but would require approximately 720,000 MWh of battery storage to maintain continued grid operation for up to 48 hours during low wind and solar output conditions.

The graph also shows carbon intensity values for B100 biodiesel-fired, absorption heat pumps. Such heat pumps can achieve efficiency levels of 120 to 130 percent, depending on manufacturing design, with future increases expected.

The hourly analysis performed for this evaluation shows that the carbon intensity of B50 biodiesel blend is approximately equal to, or somewhat higher than, heat pumps during mild weather, but significantly lower than heat pumps during cold weather, which is when the grid is under greatest stress. This raises the question of what energy resource strategy would be most effective during cold weather. The carbon intensity of B100 biodiesel is lower than all other existing energy options throughout nearly the entire temperature range.

To note, there are also wide variations in the carbon intensity for heat pumps due to the higher heat rates for power generation which occur during morning and evening peak periods. There is considerable merit to the argument that heat pump controls should be web-enabled and programmed to: 1) synchronize system operation with low-carbon intensity hours; and 2) switch to an alternate fuel source during hours of high carbon intensity on the grid.

The relative CO2e emissions shown in Figure 13 are applicable to both residential and small commercial heating systems. Biodiesel and heat pumps both offer alternative pathways to the end goal of carbon neutrality by 2050, but biodiesel offers the opportunity for immediate accomplishment of major CO2e savings through the use of B100, whereas heat pumps are dependent on the future expansion of offshore wind capacity or imports of other forms of renewable power, sufficient to reach the margin of grid power load, before they can even start to become fully renewable thermal energy resources.

<u>Carbon Intensities Vs. Outdoor Temperature for Single Family Homes in MA</u>

The following graph shows carbon intensities (lbs CO2e per MMBTU of delivered heat) for the same options as shown in Figure 12 above. The carbon intensity of future generation, cold-climate heat pumps will be higher than for B50 biodiesel blends at temperatures below 32 degrees F. This illustrates the problem that cold-climate heat pumps, while having lower carbon intensities than traditional heating oil, B20 biodiesel blends, and natural gas, are nonetheless more carbon intensive than B50 and higher biodiesel blends during cold weather.

Figure 14 also shows that the B100 option has lower carbon intensity than cold-climate heat pumps during all but 30 hours of the heating season, with such exceptions occurring exclusively during mild weather.

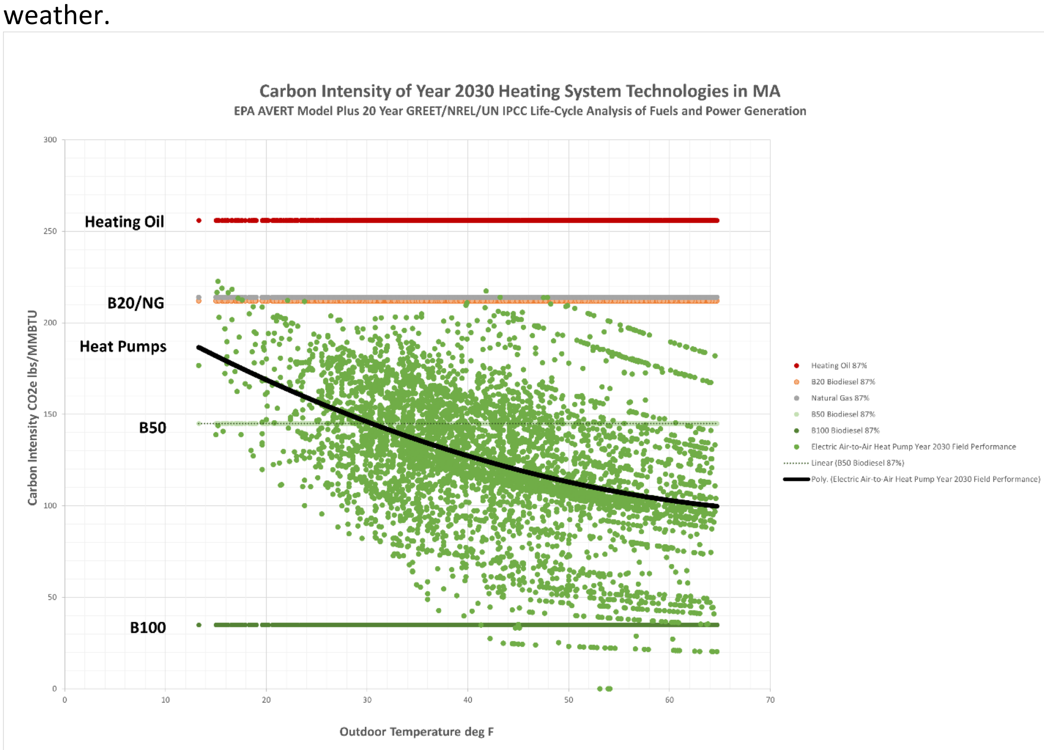


Figure 14. Carbon Intensity of Year 2030 Heating System Technologies vs. Outdoor Temperature

Increase in Grid Load Due to Electric Heat Pumps

Figure 15 shows an estimated grid load growth of more than 15,000 MW in Massachusetts for operation of residential and commercial heat pumps during peak winter conditions. The data are based on the presumption that whole-house heat pumps would be used with no fuel-fired back-up. Such grid load growth would be approximately double the existing winter peak load.

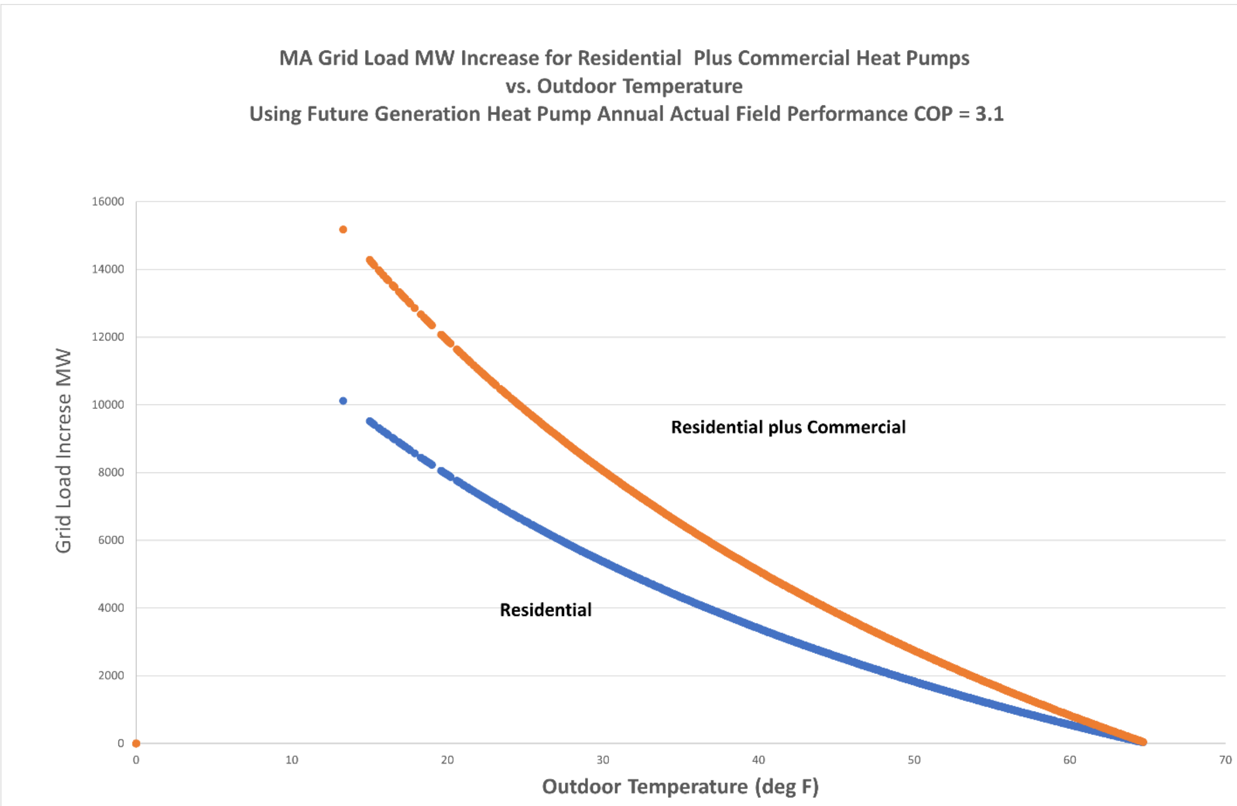


Figure 15. Grid Load Increase (MW) vs. Outdoor Temperature for Full Implementation of Residential and Commercial Heat Pumps in MA

ELECTRICAL DEMAND OF HEAT PUMPS – REALITY vs. EXPECTATIONS

Several of the references for these technical notes addressed the issue of homeowner utilization of heat pumps during the heating season. Especially in New England, there was a notable under-utilization of heat pumps during the winter, with operating hours often in the range of only 20 to 50% of technical potential.

The gray, yellow and light blue data in the graph below show average electrical demand vs. outdoor temperature trends within the heat pump populations of the three largest field studies. The graph shows a representative electric demand for a full-sized heat pump (bold dark blue data) with capacity of 40,000 Btu/hr at 0 deg F, also for a partial-sized heat pump (bold orange data) with a capacity of 15,000 Btu/hr at 0 deg F. The data curves for the three field studies show that actual electricity consumption was only a small fraction of what would be expected with full heat pump utilization. Note that the actual electrical demand curves are relatively flat below 30 deg F which indicates very low heat pump utilization below 30°F. Since heat pump power demand increases dramatically as the outdoor temperature drops further, due to increasing heat load plus decreasing heat pump COP, this means further that the homeowner percentage drop-out rate is increasing as the temperature drops.

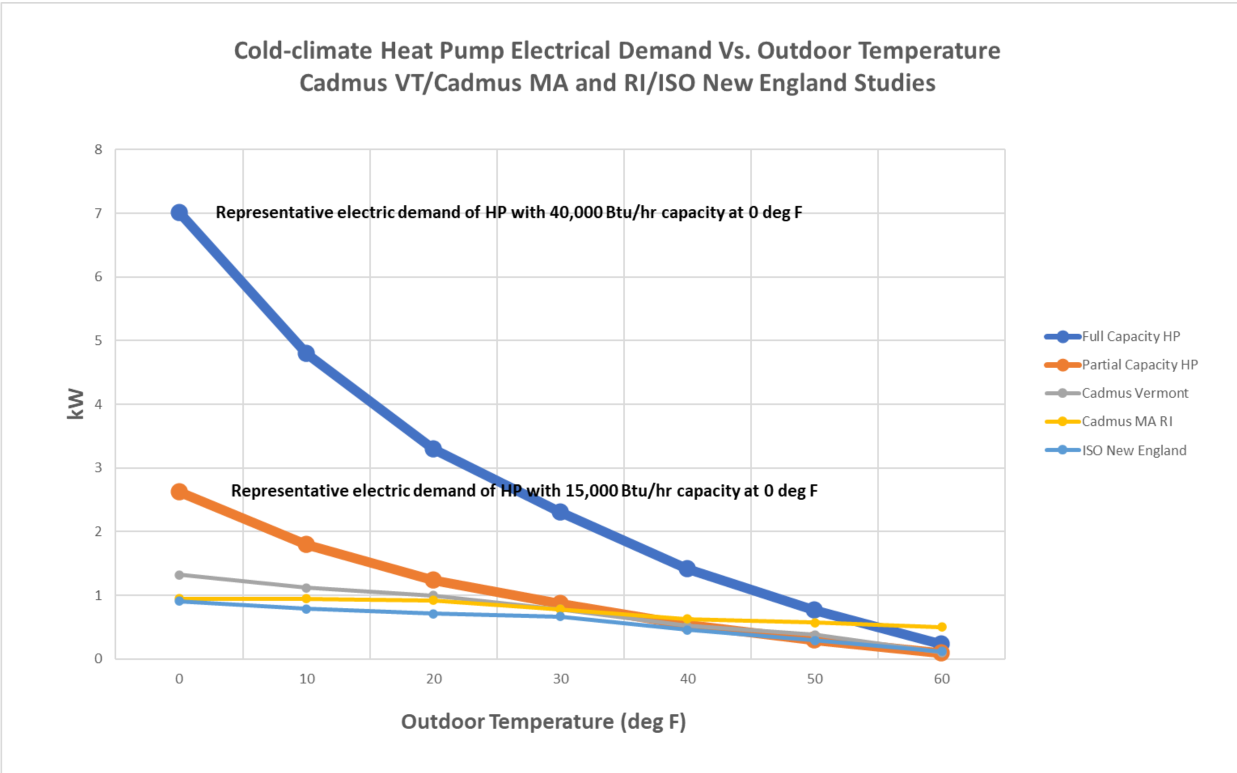


Figure 16. Cold-climate Heat Pump Electrical Demand vs. Outdoor Temperature

The bar graph below illustrates, in a different format, the same message re: low homeowner utilization of heat pumps during the winter. Homeowners have, on average, been using their heat pumps for less than half of the potential winter hours of operation. Some homeowners indeed used their heat pumps dutifully even during the coldest days of winter, but most dropped out at some point as the weather got colder, or never even turned on the systems at all for heating purposes.

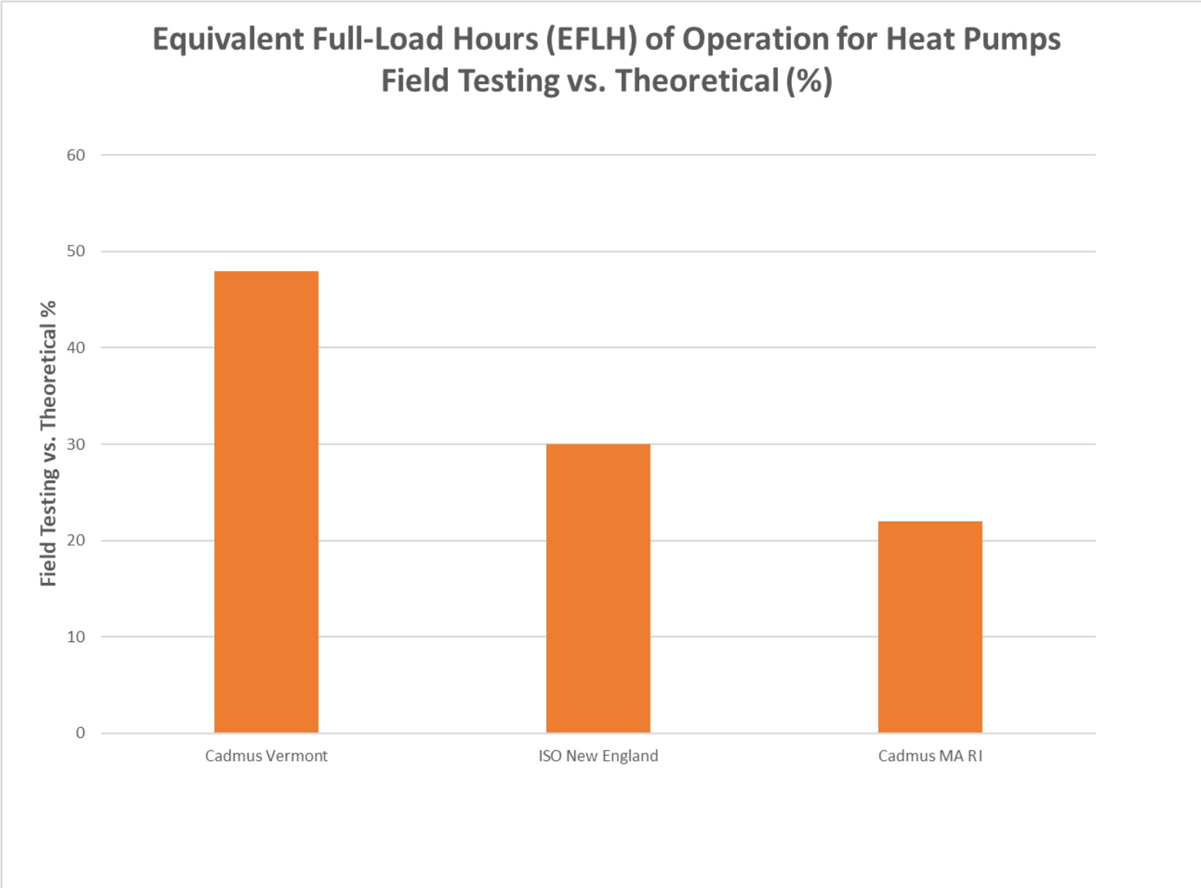


Figure 17. Equivalent Full-Load Hours of Operation for Heat Pumps

This raises the thorny issue of homeowners taking advantage of heat pump incentive programs to purchase systems that are used substantially for cooling and only partially for heating, of whether upfront incentives vs. pay-for-performance should be provided to homeowners, and whether ratepayer vs. utility shareholder funds should be used for heat pump incentive programs. There is direct relevance of the heat pump utilization question to policymaking for incentive programs in Massachusetts.

CAPITAL COSTS OF ELECTRICITY GRID UPGRADES IN MASSACHUSETTS FOR IMPLEMENTATION OF RESIDENTIAL AND COMMERCIAL HEAT PUMPS

Wind and solar projects planned for the next 10 to 20 years in Massachusetts, even if fully developed, will make a good start toward eliminating fossil generation for existing grid loads, but will not provide the substantial growth in capacity necessary for full implementation of heat pumps in the residential and commercial building sectors. Substantial capital investments will be required beyond current plans for renewable power generation and battery storage to replace fossil-based generation that would be necessary to meet increased grid loads. Major investments will also be required for transmission and distribution networks to allow renewable electricity to reach end-use customers.

Figure 15 earlier in this document shows an estimated grid load growth in Massachusetts of about 15,000 MW resulting from operation of residential and commercial heat pumps during peak winter conditions. The data are based on the presumption that whole-house heat pumps would be used with no fuel-fired back-up. Such grid load growth would approximately double the existing winter peak load in the MA zone of ISO New England.

The next graph shows an example combination of offshore wind and utility-scale solar PV nameplate capacities that could meet the winter heating loads of cold-climate heat pumps for residential and commercial buildings in Massachusetts. The blue bars represent monthly MWh consumption by residential and commercial heat pumps assuming full market penetration. The orange bars represent monthly MWh production by 10,000 MW of nameplate capacity offshore wind power. The gray bars represent MWh production by 10,000 MW of nameplate capacity solar PV power. Monthly MWh production figures are provided by the USEPA AVERT model based on historical weather data for the New England region.

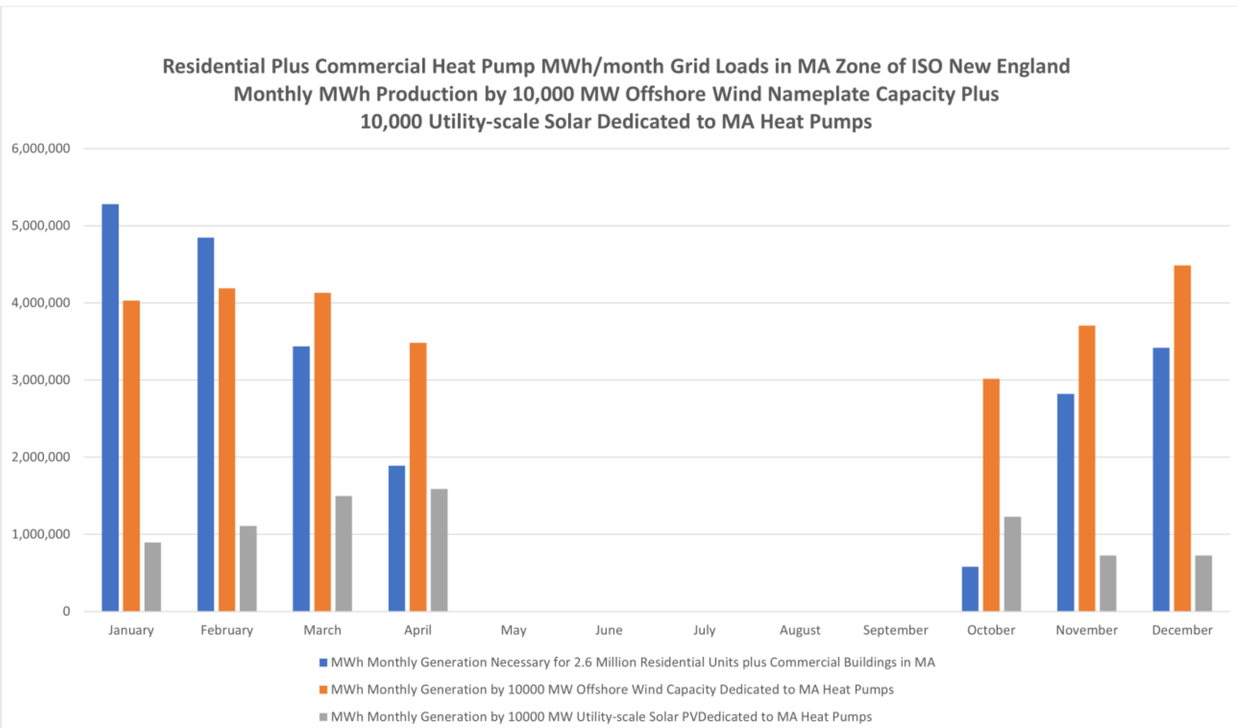


Figure 18. MA Monthly Grid Loads for Residential and Commercial Heat Pumps Plus 10,000 MW Wind Capacity Plus 10,000 MW Solar PV Nameplate Capacity

The graph indicates that an installed nameplate capacity of 10,000 MW of offshore wind plus 10,000 MW of solar PV power will approximately meet the needs of residential and commercial heat pumps in the MA zone of ISO New England during the coldest months of the heating season, assuming sufficient availability of battery storage. If it were possible to install the described 10,000 MW of offshore wind capacity at a cost of $5 million per MW, and the 10,000 MWh of solar PV capacity at a cost of $3 million per MW, the total capital expense would be approximately $80 billion. If floating-type offshore wind platforms are required, however, due to water depths greater than 180 feet, an upward revision to the wind turbine capital expense figure would become necessary.

For a MA peak grid load of about 15,000 MW for residential and commercial heat pumps, the required nominal, 48-hour, battery storage capacity, to enable continued operation during extended cold temperature and low windspeed conditions, would be approximately 720,000 MWh.

If utility-scale battery storage were to cost $200,000 per MWh capacity, based on NREL mid-range cost projections for the year 2030, the capital expense for battery storage would be approximately $120 billion, to cover the 48-hour storage discharge needed during a wind drought. This figure may be subject to adjustment, however, based on battery material price increases or decreases which might occur as the wind and solar industries grow. Increased production volumes may contribute to economies of scale, which might provide downward pressure on costs. Increased volumes of mining and extraction of materials for batteries, on the other hand, could trigger higher prices due to supply shortages. Lithium and cobalt commodity prices have recently increased multi-fold with corresponding upward pressure on battery storage prices.

Increased grid transmission capacity in Massachusetts would also be necessary to enable full implementation of residential and commercial heat pumps. While transmission upgrade costs will vary widely on a local basis depending on existing capacity and load characteristics, this analysis uses an average annual cost figure of $94 per kw-yr for New England, as developed in the 2021 Avoided Energy Supply Component Update report by Synapse Energy Economics for electric utilities and state regulatory agencies located in the ISO New England grid. The $94 figure represents a combination of construction and operating cost, e.g., labor, administration, insurance, and taxes. The corresponding, total combined capital and operating cost figure could have an order of magnitude of $2000 per kw of increased transmission capacity, although actual cost figures are highly dependent on specific circumstances. Using the figure of $2000 per kW of increased transmission capacity, the corresponding cost for 15000 MW of transmission upgrades in Massachusetts would be approximately $30 billion.

Increased local electricity distribution capacity would also be necessary for implementation of residential and commercial heat pumps in Massachusetts. Synapse Energy Economics has identified a wide range of accounting practices used by electric utilities in New England, with corresponding cost figures that range from *de minimis* to over $200 per kW-yr. More consistent accounting practices used in other states, such as New York, have indicated distribution upgrade costs ranging from $50 to $250 per kW-yr, representing variations in cost and difficulty of distribution network construction which occur in rural through dense urban environments. A corresponding, total combined capital and operating cost figure of $3000 per kW is used for this analysis. The corresponding cost for 15000 MW of transmission upgrades would be approximately $45 billion.

Recent capital cost analyses for residential heat pumps have centered on an approximate figure of $20,000 per onsite installation. The corresponding capital cost for installation of 2.6 million residential heat pumps in Massachusetts would be approximately $52 billion. The commercial building sector uses about 50% as much heating equipment capacity and energy consumption as the residential sector. The total capital cost for installation of residential and commercial heat pumps in Massachusetts would thus be approximately $80 billion.

The capital cost figures estimated above for offshore wind and solar PV generation capacity, battery storage, transmission, and distribution upgrades, as well as for onsite installation of residential heat pumps, for full implementation of residential and commercial heat pumps in Massachusetts, are presented in the following table.

Time Horizon	10 yrs	20 yrs	30 yrs
Wind and Solar PV Generation	$ 80 billion	$ 80 billion	$ 80 billion
Battery Storage	$ 120 billion	$ 240 billion	$ 360 billion
Transmission	$ 30 billion	$ 30 billion	$ 30 billion
Distribution	$ 44 billion	$ 44 billion	$ 44 billion
Onsite Heat Pump Installation	$ 80 billion	$ 120 billion	$ 160 billion
Total	$ 354 billion	$ 514 billion	$ 674 billion

Table 1. Summary of capital costs for full implementation of residential and commercial heat pumps in Massachusetts

The above table shows capital cost figures for three different time horizons. A service life of 30 years is used for the analysis of wind and solar PV generation, transmission and distribution systems. A service life of 10 years is used for battery storage systems, to reflect the limited lifetime of batteries used for daily charge/discharge cycles with depth of discharge (DOD) values in the range of 80 percent. Full battery replacement plus major maintenance/upgrades of charging controls and physical facilities have been presumed at the 10- and 20-year marks. Similarly, an initial service life of 10 years has been used for cold-climate heat pumps that are used for full heating season operation, with major (e.g., compressor/controls) component replacement required at the 10- and 20-year marks. The significant impact on long-term, total capital costs by short-lived equipment components can be seen in the table.

An earlier figure shows that approximately 22.2 million MWh of electricity would be generated per heating season by the described combination offshore wind plus solar PV system. A high fraction of the potential output of the dedicated wind/solar generation capacity necessary for winter heating would be foregone during the summer due to the high ratio of winter-to-summer peak load that would occur due to electrification of heating. A total of approximately 660 million MWh would be produced over the course of 30 years.

The total capital cost of the generation/transmission/distribution cost components would be $514 billion over the described 30-year time horizon. The corresponding energy supply cost for the described wind/solar generation system can be calculated as the $514 billion total capital cost divided by the 660 million MWh of generation over the same 30-year time horizon. The resulting marginal cost of infrastructure for electricity generation/transmission/distribution would thus be approximately $780 per MWh or 78 cents per kWh. Utility costs for administration, operations, taxes, etc., would be additional.

There are two principles of significance to note in this analysis. First, battery storage is conspicuous as an expensive component of the total capital cost for a renewable power-heat pump concept for the residential and commercial building sectors. Battery storage systems are expensive, plus they do not have the same 30-year lifetime as for generation/transmission/distribution equipment and thus need periodic replacement. Second, the capital cost of the renewable power-heat pump concept suffers from an overall low capacity factor due to the relatively high magnitude of peak loads compared to total annual energy consumption. Renewable fuels can therefore play a key role in maintaining acceptable cost effectiveness while achieving our environmental goals.

PERFORMANCE OF COLD-CLIMATE AIR-TO-WATER HEAT PUMPS

Air-to-water heat pumps are gaining popularity in the hydronic heating sector. Air-to-water heat pumps are intended to replace fuel-fired hydronic boilers in residential and commercial buildings. Air-to-water heat pumps use refrigeration cycles that are similar to air-to-air heat pumps but face the challenge of having to produce higher temperature output due to the limitations of hydronic distribution systems.

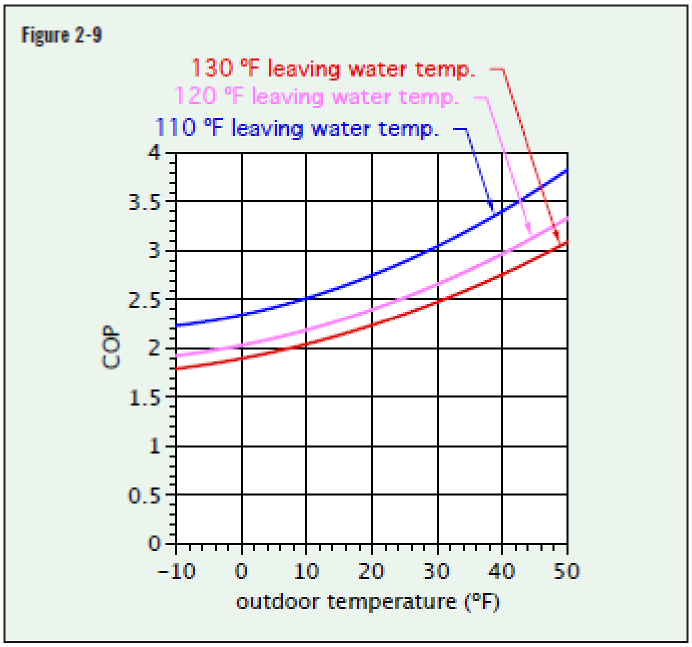


Figure 19. Example Manufacturer COP Rating Chart for Air-to-water Heat Pump

Figure 19 above shows an example COP rating chart from a leading manufacturer of air-to-water heat pumps. The chart shows, for an outdoor temperature of 30 deg F and supply water temperature of 130 deg F, a COP manufacturer rating of about 2.5, which is about 20 percent lower than shown previously in Figure 3 for air-to-air heat pumps at the same outdoor temperature. Such difference in performance significantly impacts the ability of air-to-water heat pumps to accomplish our environmental goals.

NEED FOR HIGHER LEVELS OF RENEWABLE POWER GENERATION BEFORE ELECTRIFICATION CAN ACHIEVE ENVIRONMENTAL BENEFITS

To counter the popular argument that the grid is becoming cleaner, so not to worry about power generation emissions due to heat pumps installed now, the next graph below shows the results of the EPA AVERT program relating to the year 2030 scenario in which 1 million residential heat pumps and 5,000 MW nameplate capacity of offshore wind have been installed in New England.

The fundamental problem is that 5,000 MW nameplate capacity of offshore wind eliminates the need for fossil-based power generation, to meet our present grid loads, on only a handful of days during the year. The orange slivers on top of the blue bars show the relative extent of wind energy that would be available for operating heat pumps. Any incremental loads such as heat pumps and electric vehicles over the next ten years will continue to simply increase fossil generation loads.

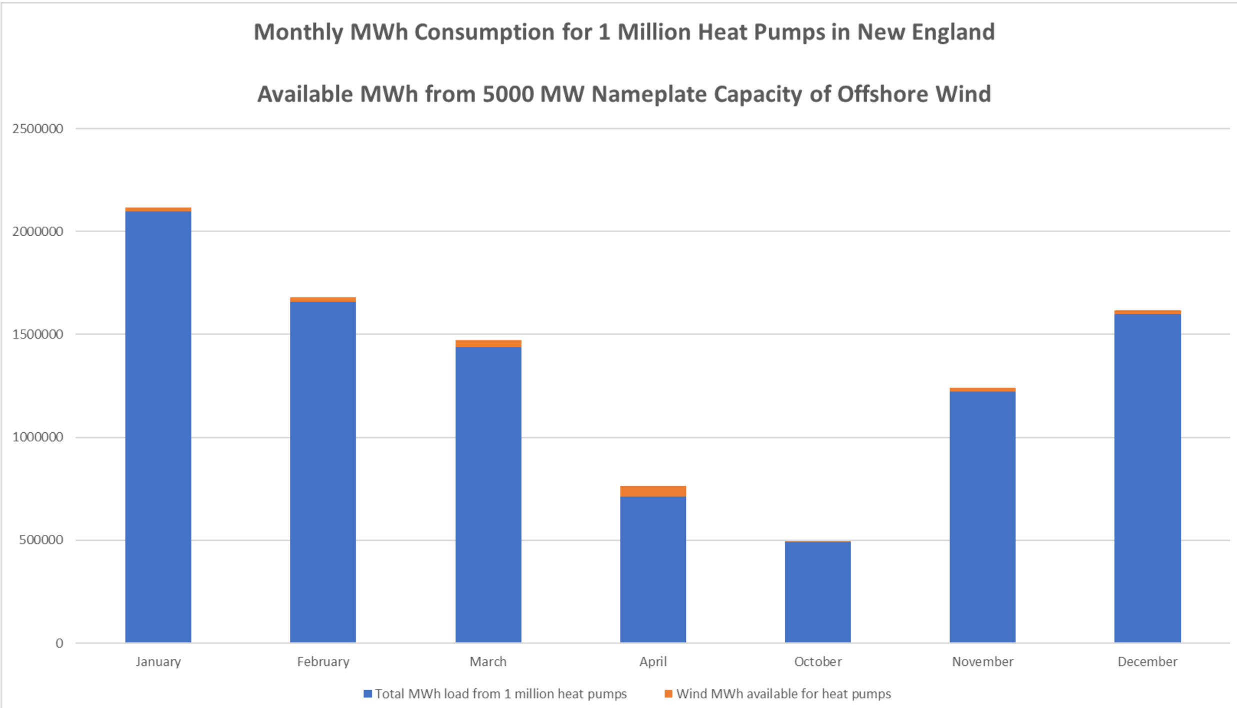


Figure 20. Monthly MWh consumption for 1 million heat pumps in New England with 5000 MW Offshore Wind

The Vineyard/Revolution/Deepwater/Mayflower offshore wind projects planned for the Martha's Vineyard coastal area are jockeying for a limited availability of transmission interconnection at the West Barnstable substation, Canal Electric Station and just a few other prospective grid injection points. Recent ISO New England Planning Advisory Committee deliberations have been consumed by the technical challenges, including voltage/frequency stability problems, of integrating offshore wind into the southeast Massachusetts grid. Even if transmission limitations are resolved, the wind projects planned for the next 10 years, even if fully developed, will be insufficient to eliminate fossil generation, except during a very few hours. Thus, any intentional grid load additions for heat pumps or electric vehicles will have to be met with fossil generation.

The result will be that most heat pumps installed today, if fully utilized for heating thus dealing with a service life of just 10 years or so, will not achieve a single molecule of CO_2 reduction compared to B50 biodiesel blends, while incurring huge capital costs and exerting upward pressure on electricity rates.

IMPACT OF HEAT PUMPS ON ELECTRICITY RATES

When cold weather comes to New England, and as grid loads climb, the cost and carbon intensity of power generation at the margin, produced to meet thermal loads, increase as older equipment comes on line and less environmentally-friendly fuels, such as coal and no. 6 residual oil, are used. Market clearing prices for wholesale power in the ISO New England control region are set by the last generation plant to clear hourly Day Ahead or Real-time auctions, with the last plant, by definition, having the highest bid price. The corresponding wholesale power rate in $/MWh, attributed to the generation plant at the margin, is then paid to all operating generators within the control region. This means that the total cost of power to customers is set by the most expensive generators to clear the auctions, which means higher electricity costs for everybody when the New England grid is under stress.

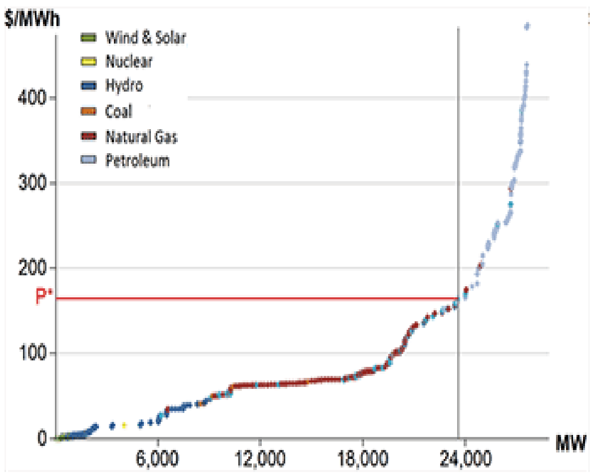


Figure 21. Example ISO New England Price Curve ($ per MWh) vs. Grid Load (MW)

The above graph shows an example curve of $/MWh cost versus MW of grid load within the ISO New England control region. It shows wind, hydro and solar PV power, then nuclear power, as providing the bulk of power up to a level of 6,000 to 9,000 MW. Natural gas-fired, combined cycle systems provide much of the output in the range of 9,000 to about 15,000 MW and lower efficiency, steam-cycle and simple-cycle turbine generators then pick up the remainder of grid load. The graph shows that it is possible to double the wholesale price for power supply by adding just a few thousand MW of grid load.

For each 1 million homes converted to heat pumps, approximately 6,000 MW of additional grid load would occur during cold weather. It is understood that many policymakers are seeking to achieve a fully renewable power grid with no further use of fossil fuels. But until the ISO New England grid achieves renewable generation at the margin, which is several decades over the horizon, fuels will need to be used to produce power for electrically-driven heat pumps, which add to the already sharp peak load characteristics of the grid. The high cost of operation for antiquated generation equipment using non-renewable fuels will translate into continuing higher power costs for all ratepayers.

The onsite use of renewable fuels, instead of heat pumps, for thermal applications in residential and commercial buildings, will provide relief to the ISO New England grid, especially during peak load periods, with significant cost savings to all ratepayers. For the short term, renewable fuels need to be used in sufficient quantity to drive ISO New England grid demand down to the level that can be served by combined-cycle power plants, rather than steam-cycle or simple-cycle turbine facilities. For the long-term, renewable fuels need to be used to eliminate the use of fossil fuel-fired generation at the margin.

The economy-wide, cost savings attributable to the capping of peak wholesale power rates will depend on the relative growth of solar/wind generation resources compared to the grid demand increase caused by electrification of the buildings and transportation sectors. Especially if heat pump-driven grid demand starts to grow more rapidly than might be offset by new offshore wind power production, it is reasonable to infer from the ISO New England price graph that an avoided cost savings of $30 per MWh of real-time grid load could be achieved during the winter season using biodiesel instead of heat pumps. All electricity customers would benefit from such grid load reduction due to the resulting drop in the wholesale price of electricity by the previously described $30 per MWh.

ISO New England Forward Capacity Market cost savings would also be achieved using biodiesel, since ISO New England will become a winter peaking grid after approximately 1 million residential living units have converted to heat pumps. At a market rate of approximately $5 per kW/month for ISO New England and based on an average peak heat pump demand of about 6 kW per living unit, the annual cost of additional generation capacity would be in the range of about $360 per living unit.

Air Quality Benefits of Biodiesel - NOx Impact Compared to Electric Heat Pumps

Biodiesel blended with heating oil can reduce emissions that are harmful to human health and the environment. These include direct reductions in particulate matter, sulfur oxides, nitrogen oxides, carbon monoxide, aromatic hydrocarbons, and lifecycle reduction for carbon dioxide and equivalent greenhouse gases. Emission benefits increase with the percentage of biodiesel from 5% (B5), 10% (B10), and 20% (B20), and are meaningful even at low blend levels.

Carbon Dioxide (CO_2): 100% biodiesel reduces lifecycle greenhouse gases (primarily CO_2) by 81%[1,2]. The corresponding reductions for B5, B10 and B20 blends of biodiesel would be 4%, 8%, and 16%, respectively. Carbon reductions on the order of 80% can be achieved by B100 currently with further improvements expected as processing incorporates higher efficiency and utilization of renewable-based methanol and electricity input.

Nitrogen Oxides (NO_X): Study results vary as nitrogen oxide emissions vary with the type of appliance as well as the blend of biodiesel. For residential space heating equipment, typical biodiesel blends (up to B20) can produce NOx reductions between 5 and 7.5%. Commercial boilers using higher blends can reduce NOx by as much as 35% using B100[3].

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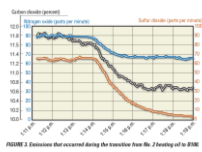
[1] Weighted average computed by NBB using 2015 EIA and US EPA EMTS feedstock data and the latest published studies on feedstock-specific lifecycle analysis. http://www.eia.gov/biofuels/biodiesel/production/

[2] Pradhan, Shrestha, Van Gerpen, McAloon, Yee, Haas, Duffield; Reassessment of Life Cycle Greenhouse Gas Emissions for Soybean Biodiesel; American Society of Agricultural and Biological Engineers; 2012; http://www.researchgate.net/publication/234143981_Reassessment_of_Life_Cycle_Greenhouse_Gas_Emissions_for_Soybean_Biodiesel/file/d912f51234a621f896.pdf

[3] Krishna, Biodiesel Blends in Space Heating Equipment; Brookhaven National Laboratory; NREL/SR-510-33579; 2004

The table below shows NOx emission factors (lbs per MMBTU of delivered heat) for Bioheat-fired boilers and for cold-climate heat pumps driven by several common configurations of power generation with and without emissions controls. The table shows typical values for both steady-state and peaking operation.

Biodiesel-fired Boilers and Electric Heat Pumps
Typical NOx Emission Factors lbs per MMBTU Delivered Heat



	Steady-state	4 hr Peak Load
Combined Cycle w/SCR and OC (5 ppm @ 15% O2)	0.02 lb per MMBTU	0.15 lb per MMBTU
Combustion Turbine w/SCR and OC (5 ppm @ 15% O2)	0.03 lb per MMBTU	0.25 lb per MMBTU
B20 – B100 Boiler (<100 ppm @ 3% O2)	0.10 lb per MMBTU	0.10 lb per MMBTU
Combustion Turbine w/DLN or H2O (30 ppm @ 15% O2)	0.16 lb per MMBTU	0.25 lb per MMBTU
Steam Cycle Gas/Oil (200 ppm @ 3% O2)	0.25 lb per MMBTU	0.30 lb per MMBTU
Combustion Turbine w/o emissions control (150 ppm @ 15% O2)	0.80 lb per MMBTU	1.00 lb per MMBTU

Figure 22. Typical NOx Emission Factors for Residential and Commercial Boilers and Heat Pumps

Although combined-cycle and simple cycle combustion turbine systems with SCR and OC emission control can indeed produce lower levels of hourly NOx emissions than direct-fired combustion systems during off-peak steady-state operation, it must be remembered that most thermal loads occur during either morning/evening peak periods or during cold weather when peaking operation becomes dominant for power generation at the margin. Under peak load conditions, the direct combustion of B20 to B100 blends show the lowest level of NOx emission factors among the options shown.

Heat pump operation during winter peak periods can thus frequently result in higher total NOx emissions than individual fuel-fired heating systems. One 350 MW combined-cycle unit (e.g., GE Series 7 HA Frame with HRSG) could heat 60,000 homes via cold-climate heat pumps but would emit NOx equal to about 120,000 natural gas/Bioheat-fired home heating systems during a 2-hour start-up period from cold or lukewarm generator status. The low-level area source of NOx associated with the direct combustion of biodiesel blends would then be concentrated into a major point source that falls under US EPA Title 5 Clean Air Act emissions standards. Possible environmental justice concerns would result due to high local emissions in low-income neighborhoods adjacent to power plants.

MassDEP and MADOER should perform a comprehensive analysis of power generation in Massachusetts and consider the imposition of requirements for NOx offset projects to mitigate negative air quality impacts in economically disadvantaged neighborhoods adjacent to power plants.

APPENDIX

NEED FOR USE OF MARGINAL EMISSIONS FACTORS FOR POWER GENERATION

On the Importance of Marginal Emissions Factors for Policy Analysis

Environmental nonprofits WattTime and Rocky Mountain Institute recommend marginal rather than average emissions factors be used for analysis of policies whose goal is to reduce carbon emissions. This primer explains why.

The purpose of average emissions factors is to apportion environmental responsibility.

A common technique in environmental analysis is to divide responsibility for cleaning up pollution equally between the different actors in a power grid on the basis of their relative power consumption. For example, if a given city consumes 5% of all the electricity produced in a given power grid, it is simple and intuitive to call it responsible for 5% of all the emissions in that grid.

The virtue of this technique is its simplicity. Each city or company on a power grid can simply calculate the average emissions per each kilowatt-hour on its local power grid; measure its own kilowatt-hours consumed; and multiply to determine its "share" of a given grid's pollution.[1]

Average emissions factors should *not* be used to measure environmental impact.

Historically, average emissions rates have been a convenient way to apportion "ownership" of different organizations' responsibility for emissions. Unfortunately, as momentum builds for institutions to more actively manage emissions, a worrisome trend is the growing number of organizations mis-applying average emissions factors to estimate the impact of environmental decisions. Yet this approach does not accurately measure environmental consequences. Returning to the previous example, it's entirely possible that the exact 5% of the grid's electricity that city is consuming comes predominantly from aging natural gas power plants, which would mean comparatively high emissions.

The correct way to measure environmental impact is using marginal emissions factors.

To protect against this mistake, the correct way to measure the impact of environmental decisions is to use *marginal* emissions factors.[2] Marginal emissions factors measure the actual environmental consequences of taking different potential actions on the power grid.

If the example city is evaluating an energy efficiency measure to conserve one megawatt-hour of electricity consumption, this program will reduce local emissions by reducing output at one or more power plants. But *which* power plants? Many sources of power, for example most solar panels, are designed to send all the energy they can to the power grid no matter the level of energy demand. Thus, they will be completely unaffected.

[1] See, e.g. the GHG Protocol Corporate Standard.

[2] See, e.g. the GHG Protocol for Grid-Connected Electricity Projects.

Conserving energy only affects some power plants: those which can scale up or down in response, known as the "marginal" power plants. Marginal emissions measure the emissions per kilowatt-hour only from these power plants, thus accurately measuring real-world results.

Why using average emissions can lead to incorrect policy conclusions.

When a power grid experiences a change in energy demand—for example, adding electric vehicles, or installing new clean power—that changes the emissions from local power plants. But some power plants are completely unaffected, for example, most solar panels and nuclear plants.

Using average emissions factors to measure the effect of environmental decisions implicitly assumes that energy policy-making affects all power plants equally. This overestimates the effects on these unaffected plants, and underestimates the effects on the marginal plants which actually do change in response to policy. If these plants have different emissions rates, this can lead to incorrect measurement of policies.

This is a growing problem because the more "always-on" clean energy a region installs, the more inaccurate any analyses using average emissions factors become. For example, on Friday May 3rd, 2019 at 1:30 PM, the CAISO website reported the following data regarding real-time energy supply and emissions. CAISO was delivering 23, 690 MW of power at an emissions rate of 3,042 $mTCO_2$/hour. Nearly 50% of the total supply (12,086 MW), was from renewable sources. Using an approach of average emissions, one would say that the current emissions rate was 283lbs CO_2/MWh.[3]

However, the marginal emissions rate for the same time was much higher, at 927 lbs CO_2/MWh. Despite the high penetration of midday solar, if 1 MWh of load was added to the grid at this time, the solar plants would likely not be the type of fuel responding to the increased load. It is more likely that an inefficient gas generator would ramp to meet the increased load, thus creating an emissions impact of 927 lbs of CO_2.[4]

As seen here, true emissions rates can be up to four times higher than average emissions-based estimates would imply, with major consequences for policy evaluation.

If policymakers were to only allow technologies that were below the average emissions levels, they might inadvertently allow existing, inefficient generators to operate more than they intend. The result would be restricting projects are that good for the environment, instead of encouraging them.

[3] California ISO real-time energy data.
[4] WattTime marginal emissions data.

Common situations in which marginal emissions is most important.

Marginal emission factors should nearly always be used in environmental impact analysis. Leading researchers apply them when measuring everything from renewable energy, to electric vehicles, to energy storage.[5] But they have particular importance for public policy whenever a policy measure is comparing different options, for example:

- *Comparing what times are best to use or store energy*. Marginal emissions should be used to select which times are cleanest, such as for energy storage.[6]
- *Comparing where is best to site a new energy asset*. Marginal emission rates should be used to measure the impact of new renewable energy, particularly in selecting locations.[7]
- *Evaluating electrification*. Marginal emissions rates should be used when evaluating the environmental impact of electrifying fossil fuel technologies such as vehicles, water heaters, and appliances. For example, in some coal-heavy regions, switching from a gasoline-powered car to an electric vehicle can actually increase, not decrease emissions.
- *Evaluating low-emissions energy sources*. Marginal emissions rates should be used to evaluate the environmental impact of low-pollution electricity generation technologies such as fuel cells and biomass. These technologies are sometimes mistakenly thought to increase emissions if they emit more than the local average emissions rate. But in reality they reduce emissions anywhere they less than the local marginal emissions rate.

For more information about average vs. marginal emissions, see this joint WattTime-RMI post.

How to properly design policy based on data-driven marginal emissions rates

Several large, influential public agencies (the CPUC), and private customers are committed to accurately reducing carbon emissions by using marginal emissions analysis. In December of 2018, the CPUC staff released a draft regulation directing the commission to require entities utilizing public incentives in the Self Generation Incentive Program (SGIP) to use marginal emissions rates to determine the net GHG impact of their project.[8]

Creating effective regulations and policy, as the CPUC has done, requires thorough data analysis and stakeholder engagement. As an independent, third-party non-profit, WattTime was founded to guide policy makers and regulators through this process to ensure that their efforts accurately reduce greenhouse gas emissions.

[5] See, e.g. Hittinger and Azevedo (2015), Callaway et al (2017) or Fares and Weber (2017).
[6] E.g. the California Public Utilities Commission's decision to use marginal emissions in real time for energy storage.
[7] See, e.g. Boston University's recent decision to buy renewable energy outside Boston using marginal emissions.