Highlights extracted from my answers to your questions, which follow.

1. Pathways severely underestimates the peak demand that would result from electrification of building heating, hence underestimates the extent and cost of new electrical infrastructure that would be required.
2. Combustion turbines fuelled by hydrogen are not a credible solution, especially to generate electricity for heating, which has much higher and longer duration peaks than apparently recognized by Pathways, hence would need even more combustion turbines and consume more hydrogen, which would be unnecessarily costly in view of an obvious alternative.
3. District heating could serve most of the heating load, thereby avoiding much of the proposed new electricity infrastructure and specifically the hydrogen fuelled combustion turbines.
4. More nuclear may be needed. It would be better to have more surplus power and a reliable supply than to continue producing greenhouse gases and/or compromise reliability, hoping in vain that hydrogen fuelled combustion turbines will prove viable.
5. District heating is another potential market for nuclear and bioenergy and would make them dispatchable through Combined Heat and Power (CHP). This would phase out gas plants, without hydrogen.
6. Two of the new uses of surplus power could be temporary deration of nuclear CHP while cogenerating heat and dispatchable or interruptible industrial heat pumps serving district heating through large scale thermal energy storage.
7. Ontario needs a thermal strategy (for heating and cooling) incorporating community energy plans into provincial plans. Without it, energy will become even more ruinously expensive than it needs to be, resulting in loss of competitiveness and great hardship, possibly a consumer revolt.

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***Do you believe additional investment in clean energy resources should be made in the short term to reduce the energy production of natural gas plants, even if this will increase costs to the electricity system and ratepayers?***

Yes*.* The costs of climate change far outweigh the costs to the electricity system of reducing emissions. Even with best efforts all around, it will be difficult for Ontario to meet its emission reduction target for 2030. Grid emissions negate reductions in all sectors relying on electrification. The electricity system is largely a public asset and should be managed in the best, broad public interest, including pursuit of emission reduction goals across the whole economy. Therefore, everything that can be done should be done to contain emissions in the short term and eliminate them across the whole economy in the long term. The cost of investments in clean energy resources that are possible in the short term are not going to have a major impact on hydro rates.

***What are your expectations for the total cost of energy to customers (i.e., electricity and other fuels) as a result of electrification and fuel switching?***

It will probably increase, though it’s impossible to say in total for everyone because future energy prices cannot be accurately forecast. Certainly the costs to low-income rate payers would be disastrous if electrification is relied on to decarbonize building heating. They won’t save on transportation fuel because they can’t afford EV’s. Electricity bills are a significant portion of their income and electricity delivery charges make up a large percentage of their monthly hydro bills because they are the same for everyone and the poor do not consume much electricity. Whereas Toronto Hydro states that delivery charges are 40% of a typical bill, in my case they are 70% because I am thrifty. Delivery charges would become especially onerous for low-income rate payers if more transmission and distribution capital expenditures were loaded on the rate base to deal with the very high heating peaks. Heating is an inappropriate use of inherently costly electricity system assets. It’s like using a chain-saw to cut butter, an expensive chain-saw. Before the climate emergency, we have not had to think too much about it in Ontario. Now we must choose between electricity and local, lower quality energy delivered through hot water pipes. The latter would be a lot more affordable.

Air source heat pumps may reduce energy consumption but still severely impact peak demand, which dictates system and distribution capacity requirements. Future electricity costs will be driven mostly by capacity requirements. On the coldest days, when most heat is required, their efficiency is very low and they need supplemental resistance heating (for zero emissions), resulting in an overall effective efficiency not much, if any, better than electric resistance heaters. Therefore, the very high heating peak in Ontario, around 60 Gigawatts (GW) would become an incremental electrical demand. Pathways erroneously assumed technology improvements would result in air source heat pumps maintaining efficiency at the coldest temperatures. That defies thermodynamics. It is wishful thinking, not planning, more like “wishing and hoping and dreaming and praying.” A more realistic, proven, down-to-earth, strategy is needed to decarbonize building heating, as introduced below.

***Are you concerned with potential cost impacts associated with the investments needed?***

Yes, because: (1) Pathways estimates it to be $400 billion, resulting in increased unit costs of electricity of 20-30% in real terms, (2) this is probably under-estimated due to the under-estimation of infrastructure that would be needed to serve building heating, (3) it has probably under-estimated the volume of hydrogen that would be consumed because it seems to not take into account that whereas electrical peaks are for a few hours, heating peaks can last days, and (4) the part driven by heating could be largely avoided. See answer to next question.

***Do you have any specific ideas on how to reduce costs of new clean electricity infrastructure?***

First, direct Ontario Power Generation to initiate discussions with Enwave Energy Corporation about supply of hot water from Pickering or Darlington nuclear generating stations. Stress that approval of refurbishment of Pickering B depends on this.

Second, change the name of the Electrification and Energy Transition Panel to Decarbonization and Energy Transition Panel. Get some district energy expertise on board and emphasize that the objective is to achieve zero emissions at minimum cost, not maximize electrification per se.

Enwave must decarbonize. The City of Toronto required it by 2030 in their TransformTO plan. Their owners, the Ontario Teachers Pension Plan, have stated their commitment to zero emissions in all their investments by 2030. It won’t be achieved by 2030, but it should be soon moving strongly in that direction. Their customers would be pleased, as it would enhance their Environment, Social and Governance (ESG) score. The road to decarbonizing would be to first convert from steam to hot water distribution, as was done successfully by Public Works in Ottawa and several universities (Dalhousie, UBC, Stanford, Rochester and the U of T is moving that way with its geo-exchange project).

That will be a billion dollar plus commitment for the public good from a private corporation, which is also striving to ensure our teachers get the pensions they richly deserve. Ontario could help by supplying heat from existing or new nuclear generating stations. Existing and refurbished nuclear units should be retrofitted to operate as Combined Heat and Power (CHP) units. CHP should be a condition of permitting any new base load, thermal generating units, whether nuclear or bioenergy.

Following conversion to hot water, and given access to a potentially very large source of low marginal cost, clean heat, Enwave could rapidly expand to supply many more buildings thereby obviating the need for heat pumps in every building. That would also facilitate expansion of their deep lake water cooling system, which would shave the summer peak.

This big win for district energy in Toronto would stimulate demand for its development throughout the province. The real estate industry would demand it when they saw how neatly it solved their problem of having to decarbonize and meet municipal green standards. It would avoid investments in their own equipment, with associated building modifications (e.g., to the roof of multi-story buildings to accommodate air source heat pumps).

Increases in winter peak demand, with consequent new electricity infrastructure, would be avoided. Not having to build it in the first place would be the most cost-effective way to reduce costs of new clean electricity infrastructure. And elimination of reliance on hydrogen would reduce costs. CHP and demand management could take over much, or all, of the intermediate and peaking duty.

District energy is highly bankable due to firm contracted long-term revenue streams from service fees, very similar to the real-estate business. It enables financing by pension funds and insurance companies, aided by the Canada Infrastructure Bank (for example as they have, respectively, invested in and provided debt financing to Enwave). Besides Enwave and Creative Energy (out of Vancouver, also active in Toronto), there is no lack of experienced, deep-pockets district energy developers in the world who would respond to requests for expressions of interest and do the job, given demand from the real estate industry and enabling government policies. Mandating new thermal generating stations to be CHP proved successful in Denmark.

There would be little to no adverse impact on hydro rate-payers. On the contrary, the electricity system would benefit from CHP. Steam turbine generators have the inertia valued by the IESO for frequency support. The ratio of power and heat production can be controlled to follow variation in electricity demand, thereby supporting more renewable energy, unburdened with overbuild and storage. CHP would be the backup, not gas plants, allowing compliance with the Clean Electricity Regulation. And it would avoid the delusion (or pretense) that hydrogen will eventually fill the role of intermediate and peaking generation, a vain hope that is another case of “wishing and hoping and dreaming and praying”.

Large-scale district heating with thermal energy storage would provide a market for surplus power, leveraged by industrial heat pumps. The extra revenue to the electricity system would mitigate hydro rate increases.

The potential for reduction in emissions from buildings by nuclear CHP is greater in Ontario than the avoidance of emissions from the electricity sector alone that could be accomplished by conventional nuclear. Hence, its social benefit would be higher, which would improve social acceptance and ESG standing, which, in turn, would lower financing costs, with consequent lower costs to hydro rate payers.

Buildings in rural areas, and very low-density residential areas, where they have space, could use ground-source heat pumps that are still efficient, and don’t lose capacity, at the coldest air temperatures, and are therefore not so stressful to either the grid or the local distribution system. They also have space for individual thermal energy storage, which could make them dispatchable loads.

District heating is inherently more suitable than the electricity system for delivering heating because heating has high and long duration peaks and district heating requires less capital per unit of peak demand, per kilowatt (kW), and thermal energy storage costs about 1/200th of electrical energy storage per kilowatt-hour (kWh) stored, loses little energy over time, does not degrade over time or overheat and can be charged or discharged rapidly. As already mentioned, but it bears repetition, electrical peaks are for a few hours but heating peaks last days. The magnitude and duration of heating peaks would be a threat to the security of the grid, but could be handled by district heating economically with no longer any peaking plants but instead very large thermal energy storage.

If building heating were to be electrified, the new electrical peaks would closely follow the heating peaks because the effective efficiency of air source heat pumps with supplemental resistance heating and defrost cycle is low at the very cold temperatures when heating peaks occur. Needless to say, they occur almost every year in Ontario, sometime in January or February.

For the purpose of estimating the impact of heat pumps on required electrical capacity, it is not the energy consumption that matters, but, rather, the peak demand. That is when kW of heating demand translates almost directly to kW of electricity demand. As previously mentioned, Ontario’s heating peak is estimated to be about 60 GW (adjusting gas consumption down for efficiency). That figures because Enbridge Gas state their annual peak demand is 120 GW (in their ‘Pathways’ report). Although that includes industry and power generation, more than half would be building heating, including domestic hot water.

Based on escalation of unit costs in a previous detailed study, [The Potential for District Energy in Metropolitan Toronto](https://bi-ib.ca/resources/) (‘the Metro Study’), updated for pipe installation costs from recently built projects, recent proposals in the Greater Toronto Area, and many feasibility studies, it appears district heating can be provided in Ontario today generally for under $3,000/kW of connected load. That includes the equivalent of generation, transmission, distribution and the heat pumps in buildings. In contrast, Pathways calls for $400 billion of investment for 50 GW of effective new capacity (Appendix A, tab 11), i.e., $8,000/kW, and the individual building heat pumps would add another roughly $1,000/kW.

Hence, new electricity infrastructure to meet the heating peaks would cost customers about three times the equivalent district heating infrastructure. The latter would be paid for by heat customers, as it should, not electricity rate payers. It would entail a higher fraction of local economic content, being comprised mostly of engineering, installation, pipes, heat exchangers and valves, in contrast to the more expensive materials and equipment essential to the electricity system, mostly made outside Canada.

One canard often heard is that hot water cannot be supplied the required distance from central generating stations into urban areas. The contrary is proven by many systems in Europe. In the case of hot water supply from Pickering to supply a large part of Toronto, the capital cost of the connecting pipes, supply and return, (probably submarine on the lake bed part way, and part way in a tunnel), according to the recently updated unit costs for pipe, but subject to detailed design and costing, would be over a billion dollars, depending on how much of the capacity is connected and how. But the value of the market is over $3 billion per year. It may be suitable for a third-party developer to build, own, operate and maintain under a tolling arrangement much like Highway 407. It would certainly be essential to employ a constructor with specific experience in this type of undertaking.

The potential net margin can be appreciated by considering the business-as-usual cost of heating with gas, well over $100/Megawatt-hour (MWh) (which is just the cost of gas at today’s price, allowing for efficiency, and 2030 carbon price – there are additional significant avoidable costs of equipment maintenance and reinvestment) with the variable operating and fuel cost of nuclear energy, put at $3/MWh in Pathways Appendix A, tab 3.

And this should be factored down by the ratio of reduced electricity output per unit of heat output. At the extraction temperatures likely to be used that ratio is 0.2. (Reference [District Heating Supply from Nuclear Power Plants: Technical and Economic Aspects](https://www.powermag.com/district-heating-supply-from-nuclear-power-plants-technical-and-economic-aspects/), Power Magazine, March 1st, 2022, by Ishai Oliker, PhD, PE ([jtcincorp@optonline.net](mailto:jtcincorp@optonline.net)), who at one time consulted for Ontario Hydro in a study of converting Lakeview Generating Station to CHP).

Applying the ratio to the variable cost of nuclear energy results in a wholesale heat energy cost of $0.60/MWh, leaving a considerable margin below the customer’s business-as-usual cost of well over $100/MWh, with a total market in Toronto of about 30 million MWh/year (not that the entire market would necessarily be served this way, but it’s a good indication of the business potential).

That would be the true economic cost of using surplus power. This assumes that since Pathways envisages considerable surplus power (see two paragraphs on) it must envisage some degree of turn-down is possible with the new nuclear units. Therefore, the economic cost of not turning down the reactors would be the variable cost.

Extracting steam to produce useful heat in the form of hot water does reduce electricity generation a bit (0.2 MWh of electricity per MWh of heat extracted). But this would not diminish generation from base load so long as there is surplus system-wide (including from wind generation).

An indication of the extent of surplus power in the decarbonization scenario can be seen from Figure 12, which shows 26 GW of installed nuclear capacity by 2050, which could generate 212 Terawatt-hours (TWh) at the assumed 93% availability, yet Figure 13 indicates only 133 TWh of nuclear energy would be used in 2050. Evidently some turn-down is assumed.

A similar calculation for wind is not as straight-forward because its availability varies by location. But the preponderance of wind locations (all but 2 out of 16 per Appendix A, tab 3) are above the average capacity factor of 40% implied by Figures 12 and 13. Therefore, it seems likely there would be additional surplus power from wind in the decarbonization scenario (as there is now, which tends to get curtailed).

Even just the 79 TWh/year of surplus nuclear electricity capacity would support production of over 200 TWh/year of heat. (The Metro Study included energy balance calculations for Pickering, Appendix 12, showing 1.3 GW of heat could be practically produced from each 0.52 GW electrical unit, thereby derating the units to 0.185 GW electrical, a derate of approximately 64%). The potential of over 200 TWh/year is more than the total heat demand in urban areas in the entire province.

The residential and commercial heat consumption in urban areas in Ontario over the 12 months prior to December 2022 is estimated to be a little over 120 TWh. This estimate is based on reported gas consumption, assuming 85% in urban areas and 80% average efficiency. “A little over” is because heating fuels other than gas were also used, although that tends to be outside the denser urban areas. Future heat consumption is likely to be close to this with increasing floor-space offsetting improvements in building envelopes. Therefore, the market for heat for district heating is a good match for a large portion of the likely volume of surplus nuclear energy.

Based on the Pathways results, it seems considerable surplus energy is likely. This is quite intuitive given the imperative to not burn fossil fuels for load following and the high expense of hydrogen as an alternative.

The cost of derating base load generation for heat production at times there was no surplus energy would depend on the marginal cost of the resource on margin at that time multiplied by 0.2, the ratio of electricity derate to heat production. If that was still methane it would be economic but result in more emissions (though less than displaced from the building gas heating systems). If it was hydrogen in combustion turbines at 38% efficiency, it would not be economic because the marginal cost of that electricity would be about $500/MWh, according to the price assumed for hydrogen in Pathways, Appendix A, tab 3, $41 USD/MMBtu.

But as argued in answer to the next question, wide-spread district heating and dispatchable nuclear and bioenergy and more demand response and dispatchable load would reduce, and could eliminate, the need for the hydrogen fuelled combustion turbines. If any hydrogen was used, it would be for fewer hours in the years, i.e., there would be more hours in the year when surplus energy was available and TES would enable heat production to be concentrated in those hours.

And if hydrogen is used it would be better in fuels cells with heat recovery giving an efficiency of 85%. Bringing those units on line to make up for the derate due to heat production from CHP base load units would make economic sense.

To be clear, the nuclear steam systems would be base loaded, but the steam turbine generators could follow the daily variations in electric load. The nuclear CHP would thereby replace methane gas plants and obviate hydrogen gas plants.

The incremental capital cost of building, or retrofitting a nuclear power plant to CHP would be less than 5% (same Power Magazine reference as quoted earlier). Going by the Pathways Appendix A, tab 3, 2030 Build Cost of large nuclear at $7,194 (2021USD)/kW and recognizing that the heat capacity could be about double the electrical capacity (per Metro Study as mentioned) derives a heating capacity cost of about $250/kW Canadian, which is a bargain for heat plant capacity. That’s because it builds on the back of capital committed in any case to produce electricity. It would give Ontarians a bigger bang for their buck.

Sufficient CHP together with demand response, dispatchable load and storage could substitute for gas plants, including hydrogen. (Hydrogen for power generation in combustion turbines is a wretched idea – see answer to next question).

Heat demand is mostly in winter, whereas the availability of surplus power or cogenerated heat would be spread throughout the year, probably a lot in the shoulder seasons and summer nights. However, the two could be closely matched economically using large scale thermal energy storage (TES). TES would be located close to the heat loads so as to minimize the long-distance supply pipe sizes. The stored energy could be topped up, as necessary, in winter using off-peak electricity, possibly with heat pumps. As with the long-distance connecting pipes mentioned earlier, preliminary calculations (based on surveys of large-scale TES construction costs in Europe) indicate the cost of required TES would be a low fraction of the energy value. The peaking energy would be a small fraction of the total, probably less than 10%, which would cause a minor increase in the average marginal cost of heat energy (over the base cost from CHP only).

CHP units could almost instantly revert to full electric power output at any time, so electrical capacity would not be reduced. The reduced electric power while cogenerating would effectively be hot spinning operating reserve. Increasing the electricity output on CHP would provide ramping capability, and decreasing would provide turndown capability, emulating gas plants.

TES in combination with CHP would be a practical form of otherwise very expensive long duration electrical energy storage and thereby help support more wind and solar on the system to lower costs and phase out gas. When the wind blew hard and the sun shone brightly, the CHP plants could automatically adjust to produce more heat and less power and vice-versa. And if then there were still surplus power available it could be turned into heat in TES by industrial heat pumps or resistance heaters. This would effectively store electricity because the stored heat would allow CHP to produce more power than heat later, while district heating would still be served continuously from TES.

The appropriate wholesale pricing structure for electricity from CHP would cover net revenue requirements, including all annual fixed costs, with capacity payments, and marginal operating costs with energy payments – this is essentially the deal gas plants get. CHP plants could then sell heat wholesale at a bargain for heat customers but much more than their marginal operating costs, earning more profit than they would generating electricity only. But they would be obliged to respond to the IESO’s direction to ramp up electricity generation per system needs in order to qualify for the capacity payments. The district heating systems, with their large-scale TES, would be happy to receive what they needed on an annual basis – the low variable cost of energy would justify extensive TES works, which have operating lives in excess of 50 years.

Pathways Appendix A, tab 8, suggests a decarbonization scenario would have 7 GW of SMR’s plus 11 GW of new large nuclear units. There are hints that some of the new nuclear capacity might be located at existing fossil stations; Wesleyville, Lambton, Lennox and Nanticoke come to mind. Wesleyville may be close enough to Port Hope (about 10 km), Lambton might be close enough to Sarnia (about 20 km). Lennox might just be feasible to connect with pipes to Kingston (approximately 50 km). But Nanticoke (like Bruce) is definitely not ideally located to serve district heating. Nevertheless, even if some of the new nuclear capacity was located where heat energy business would not be possible, that would leave a lot of scope for nuclear CHP. The largest heat load centre, the Greater Toronto Area, is close enough to be served from existing nuclear sites at Pickering and/or Darlington. And it would be relatively easy to also convert existing units to CHP, especially those being refurbished.

The SMRs, possibly about 20 units by 2050, could be distributed close to smaller load centres (Thunder Bay, Sudbury, Windsor, Sarnia, London, St. Catherines-Niagara Falls-Welland, Kitchener-Waterloo-Cambridge, Brantford, Guelph, Hamilton, Kingston, Ottawa). Some SMRs could be located on the sites of gas plants. They might re-use the steam generation cycle modified for CHP.

Without going through the whole list, several of the gas plants are located either in or close enough to urban areas, e.g., Portlands Energy Centre in Toronto, York Energy Centre, Goreway and Halton Hills.

The Portlands Energy Centre and York Energy Centre would be particularly good locations for SMRs. Gas-fired generation may be made illegal by the Clean Electricity Regulation and transmission solutions not possible. Referring to Toronto and York Region, Pathways Appendix B admits that *“With all these facilities in place, however, winter 2050 demand could still not be met.”*

Perhaps it could if winter peak demand was reduced through district heating and SMRs were located close to the city, e.g., in the Portlands area or Downsview. There is an enlightened segment of the public well aware that nuclear has no local health impacts, but gas does. The nuclear regulators, and cities and towns should accept SMRs and MMRs inside urban areas. This concept is currently being studied by the Electric Power Research Institute in the NuIDEA project, as reported in Power Magazine, March 2nd, 2023, [Is a Nuclear Reactor Headed to the Heart of Your City?](https://www.powermag.com/is-a-nuclear-reactor-headed-to-the-heart-of-your-city/) by Aaron Larson, executive editor (@AaronL\_Power, @POWERmagazine).

Another idea, along similar lines to nuclear CHP, but which might be more applicable in certain locations, particularly smaller centres in wooded areas, is bioenergy CHP with Carbon Capture and Utilization or Sequestration (CCUS). Pathways dismissed CCUS as inappropriate for the peaking duty of gas plants. However, it did not consider CCUS with base load bioenergy CHP either for industrial process heat or district heating. An example of a likely scale for bioenergy CHP is the 65 MW heat/25 MW electrical, bioenergy CHP [operated by District Energy St. Paul](https://www.districtenergy.com/services/how-it-works/combined-heat-power/).

There is a broader emissions benefit associated with bioenergy (other than potential CCUS) that Ontario should consider and it concerns the lamentable state of our forests. Due to the decline of the pulp and paper industry, there is currently no market for wood fibre from forestry thinning to improve tree growth, or from damage from climate change effects (forest fires, insect infestations, storms/derechos, and natural die off). The boreal forest is very large. As a result of lack of management, greenhouse gas emissions from our forests will soon exceed anthropogenic sources.  Better management could be put in place if bioenergy created a market for low grade wood fibre. This is another example of how the publicly owned electricity system should look at a bigger picture than considered by Pathways.

There is also an economic development aspect to bioenergy, particularly for Indigenous communities. An example is the Nipissing First Nation, which is active in forestry. A biomass CHP might be developed on their land to serve the North Bay Regional Health Care Centre and Nipissing University. That’s just one example.

With the amount of thermal capacity projected in Pathways, (inevitably in surplus in order to achieve zero grid emissions), the electricity system could serve as a local, clean, low marginal cost heat resource that could eliminate the province’s dependency on imports of billions of dollars per year of polluting fossil fuel, eliminate the need for communities to spend billions of dollars on building retrofits and heat pumps (for example an estimated $302 billion in the case of Toronto per their Net Zero Strategy for Existing Buildings) and eliminate possibly half of the $400 billion new investment contemplated in Pathways for electricity system expansion (which may itself be a low estimate because of the unrealistic assumption about the future capabilities of air source heat pumps at the coldest air temperatures).

To an extent, heating load occurs where electricity load is at. Therefore, reducing peak heating load would be a good way to alleviate *“the cost and siting challenge for the required stations and distribution infrastructure (which) will also be substantial”* (Appendix B, page 13).

In conclusion, the proven ‘real-world’ technologies of district heating, CHP and seasonal thermal energy storage should be looked to, rather than the ‘dream-world’ technologies of hydrogen and magically efficient air source heat pumps at low air temperatures. This would generate more revenue for the electricity system without excessive capital investment. That would help moderate hydro rate increases.

***Do you have any comments or concerns regarding the development and adoption of hydrogen or other low-carbon fuels for use in electricity generation?***

Pathways decarbonization scenario employs 15 GW of new hydrogen plants, while apparently assuming that heating would add about 25 GW to the peak demand (+ reserve margin). A district heating/ground source heat pump strategy could make that 15 GW of new hydrogen unnecessary, certainly for meeting heating peaks.

Absent heating, following normal daily load variations could be accomplished with a combination of CHP, some manoeuvrable nuclear without CHP (e.g., Bruce A and some new SMRs), demand response, dispatchable load and storage. In perspective, with 20 GW of installed nuclear capacity (less Bruce) per Figure 12, and 93% availability, and a potential maximum derate of about 60% (per previous studies on Pickering) there would be up to about 11 GW of dispatchable nuclear CHP capacity, which is more than the usual 5 GW of daily load variation even without resort to the other tools mentioned. This would be made possible by large scale thermal energy storage being able to accept lots of heat at night thereby keeping the reactors at full power while the generators were derated (turned down).

It makes no sense at all to convert electricity to hydrogen at 75% efficiency, then convert the hydrogen back into electricity at 38% efficiency, then suffer 10% losses in transmission and distribution to deliver electricity for heating during the heating peaks for an overall power to heat efficiency of about 25%. Contrast that with extraction of heat from CHP, notionally 500% efficiency, with 5% distribution heat losses for an overall power to heat efficiency of 475%. Consumers would pay dearly for this strategic mistake, not to mention the cost of seventy-five new 200 MW combustion turbines with transmission connections.

Appendix D, tab 9, cell D3 states that *“Economic adoption of Hydrogen at scale will most likely require Blue Hydrogen to be imported into Ontario.”* There are many issues with this: (1) it will not be 100% emissions free because no known technology captures 100% from steam methane reforming, (2) it would cost even more than hydrogen does today (which is already too expensive to use for power generation) because of the additional cost of carbon capture, (3) compression or liquefaction for storage and transport will add more cost, and probably emissions because generation in Alberta will likely evade Clean Electricity Regulations (for example, behind the fence and/or cogeneration) and (4) there is not going to be a Hydrogen Trans-Canada pipeline so trucking costs will add to the costs and emissions, as well as being a public safety hazard.

The most reasonable expectation is that hydrogen will always be expensive and have higher value competing uses and will be best manufactured at point of use.

Based on the price of hydrogen assumed in Pathways, the cost of electricity generated from hydrogen at the assumed 38% efficiency would be approximately $500/MWh, 50 cents/kWh. Pathways projects 12 TWh/year from hydrogen. That would cost over $6 billion/year in fuel (2022 $). This does not seem to be included in the System Costs, the basis of the 20-30% increase in unit rates, so the increase would be more if hydrogen was used (and even more would probably be used because of the aforementioned erroneous assumption about improved efficiency of air source heat pumps and the apparently unforeseen by Pathways several days duration of heating peaks).

The overall impression is that Pathways uses hydrogen as a dog-whistle to more or less say “we can’t actually think of a way to phase out the gas plants”. This is not good enough. The IESO should be sent back to the drawing-board and told to come up with an economical way of getting to zero emissions as surely and as soon as possible. Rather than pretend hydrogen will be the solution, it would be better to honestly accept that the twin constraints of decarbonization and reliability may have to be reconciled by having even more base load nuclear even if it means more surplus power. Better to have surplus than not enough. CHP and district heating could turn the surplus into a valuable, marketable co-product. And so could heat pumps operating off-peak saving the energy in large-scale thermal energy storage. And so could green hydrogen at the point of use, though probably not for burning in combustion engines (unless Toyota’s dreams become reality).

Pathways painted itself into this corner by uncritically accepting the dogma that building heating must be electrified. That made an already difficult task harder than necessary. The seriousness and difficulty of decarbonization calls for a higher level of imagination, more searching for viable options, collaboration, more work and more willingness to learn from the on-going development of 4th generation district heating in almost every other cold country.

***What are your thoughts on balancing the need for investments in these emerging technologies and potential cost increases for electricity consumers?***

Hydrogen generation is not really an emerging technology as used in the way described in Pathways. It’s not emerging anywhere like that on a utility scale. Some industries currently use their excess hydrogen for generation behind the fence when they have it. There have been demonstrations of hydrogen fuel cells for power or CHP, e.g., in the U of T Mississauga campus. But transporting large volumes from Alberta to Ontario to burn in inefficient combustion turbines as an essential permanent pillar to support our electricity supply makes no sense at all, as previously discussed, when there is a better alternative.

Green hydrogen made from surplus power at night with diurnal storage, perhaps hydrides, on the site of gas plants, to fuel generation only during the day, might make more intuitive sense as a small adjunct to day-time resources. In that case, it would be more efficient to use CHP fuel cells at 85% efficiency. District heating and TES would be needed for the heat off-take.

SMRs and MMRs will be useful in place of new transmission that would be required for other generation sources. In some cases, new transmission would be next to impossible to build in time, or at all. Similarly, they would get CHP close enough to heat loads for optimal efficiency. District heating has several advantages over industrial steam customers: (1) thermal energy storage (TES) of hot water allows CHP to be dispatchable for electricity, (2) lower cost of heat production because the electrical derate is lower at lower extraction temperature, (3) TES largely deals with the lower load factor of building heating, (4) potentially larger heat hosts, (5) more of them (every city, town and cluster of buildings) and (6) more secure longevity of heat off-take contracts (“safe as houses”).

In the case of Pickering Nuclear Generating Station there is not a lot of room for SMRs and the existing station would be in the way of lake water cooling. But refurbishment of existing units could include modification to CHP.

The SMR planned for Darlington by 2028, and probably others later, is a BWRX-300. This is a boiling water reactor requiring an additional heat exchanger for district heating. This would be a steam-to-steam transformer upstream of the district heating condenser. That would be a little more complicated, but has proven to work on a large scale. Steam transformers were used for 26 years to interface between Bruce Nuclear Station A and the Bruce Heavy Water Plant.

***Following the end of the current 2021-2024 energy efficiency framework how could energy efficiency programs be enhanced to help meet electricity system needs and how should this programming be targeted to better address changing system needs as Ontario’s demand forecast and electrification levels grow?***

It should be recognized that district energy (DE) (district heating and district cooling or a combination) is the ultimate, permanent and most cost-effective energy efficiency program.

District heating will lower winter peaks while district cooling can lower summer peaks; e.g., by using deep lake water cooling and/or cold thermal storage in the form of chilled water or ice (as in Enwave’s Windsor District Energy System).

It follows that programs should target DE technologies such as those and ground source and water source (e.g., sewage or lake water or rejected heat from cooling) to water heat pumps. Almost all large buildings have essentially hydronic internal heating systems. Geo-exchange should be supported for large buildings and such facilities should be “DE Ready” to facilitate incorporation into DE.

“DE Ready” for new buildings means lower than normal internal heat distribution temperatures, and more than normal heat exchange surface to be compatible with district heating supply at no more than 65°C and return at 30°C. It should also include design drawings (civil, mechanical and electrical) specifying how the eventual connection to district energy will be made, ideally in a basement.

There should be a Clean Heat Production Credit, in the order of about $20/MWh (2 cents /kWh) of useful heat produced from non-emitting sources for the first ten years. This recognizes that, for political reasons, the carbon price does not fully represent the full social cost of emissions. It should be reduced to the extent electricity was used (for example by ground source or water source heat pumps) reflecting marginal emissions from the electricity system. Some sources, such as nuclear, solar thermal, or small reciprocating engines with heat recovery, would thereby suffer no such reduction. (It doesn’t matter, in the short term, that the reciprocating engines burn gas, provided they only operate when gas is on margin anyway, resulting in a slight decrease in emissions, taking into account emissions displaced by the useful heat).

Existing operations should be included. Although they would not provide incremental benefit, it’s only fair to reward early adopters and their publicized gains would draw attention sooner than new projects with their lead times and encourage evolution in the right direction. And it would avoid perverse consequences like operators shutting down existing and starting new. These distributed sources of clean heat could help build up the heat load supplied with hot water through district heating to eventually match planned large-scale CHP. The original heat sources with higher marginal costs would then become standby and peaking.

District heating expansion and new district heating systems should be assisted on the basis of the avoidance of new demand and electricity consumption from air source heat pumps that might otherwise be thought necessary to decarbonize building heating (though they actually would not decrease societal emissions because of the consequent increase in gas plant output).

For example, many suburban neighbourhoods could immediately benefit from district geo-exchange systems involving from a few up to about a hundred houses. The capital for vertical bore-holes, central heat pump (possibly heat recovery chiller), distribution and energy transfer stations could be amortized over 40-50 years added to the property assessments, not individual debt, which would make it easier than home owners trying to go it alone with individual geo-exchange heat pumps. The local electricity distribution companies and/or Enbridge Gas, should be encouraged to lead such projects, which might include wholly or part co-operative ownership. Currently, they are held back by the difficulties in obtaining easements (see later recommendations for policy development under ‘additional feedback’).

As another example, all schools with playing fields should have them temporally dug up to install horizontal (‘slink-toy’) ground heat exchangers for geo-exchange, or just geothermal if cooling wasn’t needed.

All of these individual systems (geo-exchange in large buildings, district geo-exchange in neighbourhoods, horizontal geothermal in schools) could be eventually linked into ‘super’ district heating systems supplied with very low marginal cost energy (e.g., nuclear and/or solar thermal). The original rotating equipment would be partly amortized by then and could be demoted to peaking duty, whereas the underground TES would remain active as part of the larger system.

***Do you have any additional feedback on the IESO’s “no-regret” recommendations?***

They are mostly good in general terms (except the dead-end of so-called low carbon fuels), but specifically miss what is essential to reach zero emissions affordably, or at all.

Pathways states, page 32) that success *“would need every known or potential resource available today.”*  Yet it ignores the potential synergies between the electricity system and heat networks, which could provide economical energy storage enabling phase-out of gas plants without hydrogen, and the great emission reduction potential of using nuclear energy for district heating.

It also ignores the potential flexibility of associated CHP with seasonal thermal energy storage. These omissions should be remedied by ensuring the (what ought to be called) Decarbonization and Energy Transition Panel and the Cost-Effective Energy Pathways Study have appropriate expertise in district energy, which does not appear to the case yet. Consultants have been hired with no indication they have any knowledge of district energy. Their models don’t even allow for it. Therefore, the government can learn little about the potential for district energy from these consultants. These studies should involve experts with specific knowledge about district energy.

Missing this opportunity should be cause for plenty of regrets. It would be a scandalous under-utilization of publicly funded assets. The building heating market in urban areas in Ontario is worth well over $12 billion/year, probably closer to $15 billion/year, and could be largely serviced from local heat sources, severing dependence on imported energy and building a sure, predictable road (unlike hoping for heat pumps in every building and hydrogen) towards cutting emissions from buildings, which is the highest emitting sector in the Greater Toronto and Hamilton Area and second highest in the province. And the load following capability of nuclear CHP could help eliminate emissions from the electricity sector also.

It would provide greater energy security and resilience, having capability, with seasonal thermal energy storage, to weather whatever long and severe spells of extreme cold that paradoxically may come due to global warming. With no such experience, it’s uncertain how a future electricity system might fair if heating for the whole province depended on it. The history of ice-storms in Eastern Ontario and events in Texas and elsewhere don’t inspire confidence in this strategy of having all eggs in the electric basket.

District heating is a simple technology with few moving parts, long-life with minimal maintenance, less embodied materials per kW than the electricity system and well-developed supply chains for its few and simple components. In particular, it is largely independent of inelastic supply chains for critical materials such as copper, aluminium, nickel, cobalt, lithium, manganese, silicon, rare-earth metals and highly engineered equipment, all made somewhere else. It affects less space, no non-urban space, is mostly underground in urban areas, puts less pressure on the construction job market and could create markets for new local industries manufacturing its relatively low-tech components like pipe, heat exchangers, valves and thermal energy meters. Sadly, but realistically, manufacturing of the often more sophisticated and heavy equipment used in electricity systems like autotransformers and turbo-generators is unlikely to come back to Ontario.

If we are about to invest billions in the energy transition, at least let’s maximize local content. Otherwise, the exercise will drain our economy.

To ensure affordability of both electricity and heating for Ontario business and low to middle income consumers, the Government of Ontario should establish policy certainty on firm and permanent support for DE starting with requirements to maximize efficiency in thermal generating stations by making economic use of otherwise discarded heat.

1. Mandate all new thermal generating stations (whether bioenergy or nuclear) to be situated and designed so as to make otherwise discarded heat available as useful heat, be constructed to be at least “DH Ready” and have standing offers to sell heat on a commercial basis. DH Ready for power plants means at least tie-ins for steam and condensate cut out and blanked and civil, mechanical and electrical design drawings approved with bills of materials.
2. Establish appropriate wholesale price regulation for CHP electrical production - for example, covering all fixed costs with capacity payments, thereby allowing CHP to sell heat for wholesale prices that would be a bargain for heat consumers yet higher than their marginal operating cost to provide return on investment for the necessary incremental works within the fence. Another benefit to the nuclear projects would be the consequent greenhouse gas emission reductions from buildings, and the avoided societal investment in electricity infrastructure and in-building heat pumps and building retrofits, which could improve its ESG standing and thereby lower the cost of financing. Cost of financing is the most sensitive parameter affecting the economic viability of nuclear plants.
3. Include district heating and cooling in Conservation and Demand Management programs.
4. Assist and enable municipalities to attract experienced, deep pocket DE developers (study what the City of Bristol has done in the United Kingdom).
5. Publicize (in collaboration with the Canada Infrastructure Bank) availability of long-term, low-cost financing for feasible district energy projects.
6. Apply the full carbon price to all electricity generation and continue increasing beyond 2030.
7. Offer a Clean Heat Production Credit. The federal government might be persuaded to co-sponsor.
8. Consider legislation, such as developed by the Department of Energy Security and Net Zero in the United Kingdom concerning Heat Network Zones, where designated categories and sizes of buildings would be obligated to connect to district heating, as would significant potential sources of waste heat (e.g., data centres). At the very least, require all municipalities, and provide them with funding, to develop Heat Plans (similar to the IESO’s electricity planning, but more appropriately conducted by municipalities). This was required in Denmark about 50 years ago and Demark now has about 70% of buildings connected to district heating, and is increasing connections all the time, including single family homes.
9. Consider legislation similar to that developed by the Department of Energy Security and Net Zero in the United Kingdom concerning district heating consumers rights. This would create more confidence leading to higher demand.
10. Recognizing that district energy development will be driven by demand from major real estate investment firms, ensure that such companies clearly understand that zero emissions, one way or another, will soon be mandated while there will be policies in place to ensure economic viability of district energy.
11. Also recognize that, while district energy in Canada is generally given faint praise by all levels of government without sufficient action, it deserves, a big, near-term “win” would un-freeze calcified attitudes. One such “win” could be to emulate what the federal government has done with its steam district heating systems in Ottawa, to strongly encourage and facilitate conversion of several steam district heating systems to hot water, thereby paving the way for their decarbonization; e.g., Enwave, the U of T and York University in Toronto, Enwave in London, Index Energy in Ajax and others. These systems already have connected customers, which is the key requirement. They might logically move towards conversion to hot water and decarbonization independently. However, as with the Ottawa steam to hot water conversion, the strong, helping hand of a senior level of government would be pivotal.
12. The IESO should be directed by the Minister of Energy to provide another Pathway to Decarbonization assuming only about a quarter of the province’s building heat load would be electrified and that only by ground source heat pumps in low density areas with individual thermal energy storage. These are more suitable where there is space available and would not pose as great a challenge to electricity distribution systems as in the highly built-up major load centres. And it should explore the notional benefit of CHP.
13. The Government of Ontario should develop a long-term strategy to transition from natural gas fuel to a truly clean source of heat between now and 2050. This will not be easy. It will be difficult to find dependable heat sources to replace natural gas. One clean dependable heat source potentially available on a sufficient scale is nuclear energy, which can be made available as heat not just electricity and probably without needing much, if any, additional installed capacity beyond that projected by Pathways in the decarbonization scenario. Another is solar thermal, which would likely develop after the basic infrastructure was put in place, as it has in Europe. Another is heat from sewage and/or water treatment plant effluent, which should be encouraged to build up heat loads prior to in-service of nuclear units. Another potential upside is closed loop deep geothermal, likely more useful for the lower temperatures needed in district heating than for power generation (this is no more ‘way out’ than hydrogen, in fact, more down-to-earth, safer and broadly replicable).
14. A provincial level strategy communicated to the municipalities should encourage local planning to allow electricity and heat production to be placed in reasonable proximity to the loads and ease legal barriers for easements for the underground services crossing property lines and city streets.
15. Encourage nuclear regulators, and cities and towns to accept SMRs and MMRs inside urban areas.
16. Incorporate municipal and community heat plants into provincial energy planning. Get a true bottom-up view of what the demand is for what and where.

Without such a bold, proactive strategy, new district heating would be limited to planned new communities where the density is high enough and the land is essentially clear so the infrastructure can be built efficiently as part of the subdivision plan, such as the Lakeview development in Port Credit. That’s all very well, but won’t go far in decarbonizing all building heating (particularly existing) or the electricity system as required by the proposed federal Clean Electricity Regulation. Policies advocated in this submission would do that.

Installation of heat pumps in every building is not going to happen because there is no payback for the owners, insufficient contractor capacity able and willing to take on the work (gentrification is more lucrative) and the process of upgrading electrical service is inevitably slow (each connection must be reviewed by the LDC individually). There is no fast road to Net Zero that doesn’t go through district heating.