ECONOMIC AND FINANCE WORKING GROUP

SMR ROADMAP

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Summary for Policymakers

Small Modular Reactors (SMRs) have the potential to radically alter the nuclear sector, being a game-changer for nuclear's business case by expanding the market for nuclear plants well beyond that previously considered for larger unit deployment. SMRs achieve their economic advantages based on economies of series, modularity and standardization for commercial deployment. This could allow the nuclear industry to be more like the airline or shipbuilding industry in terms of deployment model. Analysis conducted by this working group found that, once mature, SMR technologies would have a levelized cost of energy (LCOE) that is competitive to alternatives for meeting the energy needs of grid-connected customers as well as "off-grid" remote communities and industrial applications. Furthermore, lower capital costs, shorter construction times, and modular construction, would make SMRs easier to finance relative to conventional large reactors.

For Canada to be a leader in this burgeoning market, a Pan-Canadian effort must emerge. That is, all interested stakeholders, users and government entities should participate in SMR development, incentivized through cost-sharing and collaboration. This is to ensure that a Canadian SMR strategy represents parties with an economic interest in SMRs. Specifically:

- Government, together with private industry should make the necessary Research, Development, and Demonstration (RD&D) investments for SMRs to achieve commercial maturity. Given how such investments create spillovers, with broader economic benefits accruing beyond the firm making the investment, there is a disincentive to invest by market actors. The government, in partnership with industry, should support activities related to RD&D and building markets that benefit the broader economy more than individual firms. These will be necessary stepping-stones for SMRs to succeed, and will attract the talent and interest to develop these technologies.
- The federal government, provincial governments and industry should focus on reducing the cost of capital when financing SMRs. The cost of capital is the single greatest impact to the LCOE of a SMR. Such risk-sharing mechanisms may include loan guarantees, preferred interest rates, bi-lateral agreements or regulating the return of the first SMR. Industry and customers will also have a part to play in risk-sharing between the different markets for SMRs.
- Finally, and crucially, SMR development based on 'fleet economics' would optimize their potential. A fleet approach would see favourable SMR designs build in series, promoting standardization and learning-by-doing through the building of subsequent, identical units.

A Pan-Canadian approach is essential as the development of SMRs occur within a highly competitive international arena. Over $1 Billion worth of funding has been committed between the UK and the US to develop SMRs domestically.[1] Other competitors, such as China and Russia, have already deployed demonstration reactors and have nuclear industries with substantial government backing. Action must be now, or Canada will cede the chance to be a leader in this promising area. Thus, the key recommendation of the EFWG is that government and industry combine to support early stage RD&D and first-of-a-kind (FOAK) commercial investments in SMRs. Based on industry feedback, Canada's window of opportunity is between 6 to 12 months to gain a competitive advantage in developing SMR technology for domestic and international markets. The committed funds will promote research & development, feasibility studies, investigation of business partnerships, demonstration projects, sharing of one-time costs and risk-sharing of first commercial deployment. Funding can support advanced manufacturing and build on new and existing supply chain capabilities. Industry feedback recommends funding to be flexible on both a grant and cost-share basis, depending on need.

Recommendation: *Government to commit funding, in partnership with industry, to support activities related to research and development, development of new markets and building demonstration and first-of-a-kind projects*

A joint letter signed by 6 CEOs from Bruce Power, OPG, CNL, NB Power SaskPower, and SNC have recommended a phased approach to funding of $500M, with a release of $100M for the first phase in 2019. This funding will put Canada on the path as an internationally recognized leader in developing SMR technology and to establish a beachhead for their domestic development. This request aligns well with broad estimates of establishing a new SMR design, which is in the order of $1 - $2 billion, given a 50/50 cost-sharing (L. Diaz Anadon et al., 2011), (OECD-NEA, 2016.), (Board, 2016.).

To capitalize on Canada's opportunity for developing SMR technology, the federal government should consider using existing agencies whose mandate have within them mechanisms to approve funding, or can appropriate funding from the Federal government's budget for the purposes of SMR development. AECL is one such federal agency whose nuclear innovation mandate may include such appropriations. Programs such as NRCan's Clean Growth Program and Alberta Innovates Voucher Program serve as a good model for incenting collaboration and funding for novel and innovative technologies.

[1] EFWG calculation. For examples of US funds committed, please refer to NuScale (2014). For examples of UK funding, please refer to UK Department for Business, Energy, & Industrial Strategy (2018).

1. INTRODUCTION

In a ‘Post-Paris’ era, greenhouse gas (GHG) emissions mitigation is a global imperative. The international community is recognizing the need to reduce global GHG emissions by 70% from 2017 levels by 2060, to limit the rise in average global temperatures by $2^{0}C$ by 2100 (International Energy Agency, 2018a). However, rather than declining, global GHG emissions actually rose by 1.4% in 2017- the first-time global emissions have increased since 2014 (International Energy Agency, 2018b). Carbon-intensive fuels such as coal, natural gas and oil still constitute 81% of global energy consumption, and are rising (British Petroleum, 2018). These trends occurred against the backdrop of unprecedented global growth in the deployment of renewable energy technologies, highlighting a persisting low-carbon energy gap.

There remains a pressing need for Canada to de-carbonize its energy sector through technology and policy innovations that do not compromise Canada’s environmental stewardship standards or economic competitiveness. Nuclear energy, and specifically small modular nuclear reactors (SMRs), present Canada with several opportunities:

1- To demonstrate leadership in energy innovation with cutting edge technology.
2- To enable a low-cost way of de-carbonizing its economy in multiple sectors through the production of zero-emissions heat, electricity and hydrogen.
3- To open new domestic mining opportunities in previously inaccessible off-grid locations.
4- To leverage Canada’s existing nuclear expertise into the next opportunity for nuclear in Canada and abroad; and
5- To provide a clean source of off-grid power, potentially enabling important socio-economic benefits to Canada’s Northern Communities.

The development of abundant low-cost natural gas has been disruptive in the power sector, resulting in pervasive fuel switching from baseload coal to natural gas. However, a multitude of factors challenge the longevity and competitiveness of natural gas assets in evolving electricity markets. In the wake of coal closures, natural gas is now the most GHG-intensive fuel option. It begs the question what technology will replace natural gas in a carbon-constrained electricity market, particularly as a source of firm baseload capacity? Each alternative has trade-offs. Wind and solar, while increasingly cost competitive, will struggle to yield the sort of capacity factors and reliability needed for baseload electricity generation absent economic energy storage. The latter is improving, but may not be available at the scale required in time for timely deep de-carbonization. Geothermal offers baseload capability, but it is location-constrained, and can only be converted to electricity where accessible geothermal resources are found. Biomass still faces resource aggregation, transportation and fuel quality consistency issues. SMRs, and nuclear more broadly, can therefore play a significant role in providing emissions-free baseload generation and other grid services.

Nuclear energy can also support the electrification of the economy to decarbonize the end use sectors of transportation, residential and commercial buildings, and industry. In the near-term, electrification of public transport and passenger vehicles will require substantial increases in low-carbon electricity to the grid. Nuclear energy, alongside renewables and other non-emitting electricity sources, can be a valuable option in helping to provide this electricity. Additionally, the use of hydrogen-powered fuel-cells for transportation may present an opportunity to decarbonize long-range heavy-duty operations, such as heavy-duty freight trucks and ships. For these options, existing battery capacities pose a constraint to electrification due to their longer distances travelled. However, for hydrogen to be an effective GHG mitigating fuel, its production will require low-carbon energy inputs. Nuclear energy can produce hydrogen with zero-emissions at scale, necessary for a hydrogen-fuelled heavy transportation sector.

Nuclear energy, particularly the thermal energy from high-temperature SMRs, could also play an important role in replacing fossil fuel as a source of heat for the industrial sector. Canada's Industrial sector is the largest user of fossil fuels. The quality steam available from high-temperature SMRs could replace natural gas for in-situ extraction of bitumen from oil sands deposits as well as from chemical industries and other petrochemical manufacturing plants.

Even with aggressive GHG mitigation efforts and optimistic penetration rates for electrified modes of transportation, including electric passenger vehicles, oil is still going to be an integral part of the global energy mix for the next few decades to come. Given the transition to a carbon constrained global energy market, the carbon footprint of an oil barrel will likely become an increasingly important determinant of market access. SMRs can thus play a role to help Canada's oil sands industry to lower its carbon footprint, while producing the fuels needed in the global market. In addition to supplying clean heat and power for bitumen extraction, SMRs can cleanly produce the hydrogen used for upgrading bitumen.

Many mining operations in Canada and abroad currently use expensive diesel, operated in remote locations, as their primary energy source. Energy is a considerable fraction of an off-grid mine's cost structure- consuming 15% of revenues- and so the potential for SMRS to reduce these costs could unlock new opportunities for Canada's mining sector (ABB, 2017).

Lastly, remote communities in the northern hemisphere, including Canada's north, often rely on diesel generators for electricity. SMRs have the potential to displace diesel generators in these communities. The analysis of this working group estimates the cost of electricity from diesel generators in Canada to be approximately $400/MWh. Moreover, there are significant greenhouse gas and air pollution impacts (e.g., NOx and particulate matter) associated with the use of diesel generators. SMRs, therefore, have the potential to enhance the wellbeing of residents in these communities along multiple fronts- air quality and health improvements- as well as releasing funds for use in other initiatives by reducing funding that goes to energy subsidies.

2. WHY SMALL MODULAR REACTORS?

In Canada, commercial nuclear power plants have been safely operated for over 40 years. Canada is home to a mature nuclear supply chain that sustains tens of thousands of high quality, highly-skilled jobs and generates billions of dollars in economic activity every year (Natural Resources Canada, 2016; Statistics Canada 2017). Indeed, Canadian nuclear technology, products and services are world class and are exported around the world.[2]

Nuclear is a low-cost source of bulk energy, with low operating costs and requires little fuel per unit of electricity generated. No other energy source can produce so much energy from so little. For example, a 20 gram pellet of uranium (used as nuclear reactor fuel) produces the same amount of electricity as burning 400 kilograms of coal or 410 litres of oil or 350 cubic metres of natural gas (Canadian Nuclear Association, 2017). Nuclear power reactors are ideally suited for reliably meeting the long-term, round-the-clock power needs of an electricity grid, and can exhibit flexible operation capability (International Atomic Energy Agency, 2018). Nuclear reactors are designed to operate continuously - for multiple years at a time between outages - and have operating lives in the range of 40 to 60 years. Nuclear energy produces no carbon dioxide (a key GHG responsible for accelerating global warming and climate change) or air pollutants such as sulfur dioxide, nitrogen oxides and particulate matter that are typically emitted by fossil-fueled energy. On a life-cycle (mining, construction, operation and decommissioning) basis, nuclear is one of the lowest emissions technologies - comparable to hydroelectric power and wind energy (Weisser, 2007). Nuclear energy has a very compact physical footprint as well, being the most land-efficient means of electricity production enabling 47.6 megawatts per square kilometre or over 3000 GWh per square kilometre. By comparison, onshore wind and solar produces significantly less energy, 872 GWh and 62 Gwh per square kilometre of land used respectively, in addition to requiring sites with favourable solar and wind regimes (Canadian Nuclear Association, 2017; Cheng & Hammond, 2017).

The next generation of nuclear reactor technologies, such as small modular reactors (SMRs), promise to further enhance the safety, economic and environmental benefits of nuclear energy. SMRs, in particular, incorporate advanced safety features and are designed to achieve favourable economics through compact and efficient design for versatile applications, scalability and modular construction. They can be suitable for baseload electricity production as part of a traditional grid but can also serve as a clean energy

[2] Presently Canadian CANDU reactors operate in Argentina, China, India, Pakistan, Romania and South Korea (Canadian Nuclear Association, 2017)

replacement for diesel for remote communities and mining projects. The supply of high quality steam to industry, or acting as a clean energy source for hydrogen production, are other potential applications, as is the configuration of SMRs to complement intermittent sources of energy such as wind and solar power. Several SMRs designs also propose to burn existing used nuclear fuel to produce energy, which would have the added benefit of reducing nuclear waste in need of long-term disposal.

For the owner or operator of a SMR, a decrease in size helps to reduce the total capital budget of the project and reduce the projects risk. Potential owners/operators seeking an affordable source of emission-free electricity may not be able to take on the risk of building a mega project in the order of several billions of dollars. Cutting down the reactor size allows for these markets with smaller capital budgets to participate and become accessible. Furthermore, smaller reactor sizes and increased standardization of pre-fabricated parts can be a source of risk mitigation. Project schedule risk is often associated with the longer construction schedules, project uniqueness, and project complexity associated with larger reactors, increasing their chance of cost-overruns and schedule delays (Expert Finance Working Group on Small Nuclear Reactors, 2018). Behind schedule and over budget is a hallmark characteristic of mega projects and is a key reason inhibiting project success (Locatelli, 2018). Keeping SMRs simple, small and modular can mitigate this risk.

Since SMRs can be 50, 100 or 300 MWe in size, the capacity additions and risk of forecasting demand growth for utilities can be better managed. Many issues and risks can arise when a utility must commit financially to adding 1000 MWe of new conventional nuclear capacity on-grid, with commercial operation many years later. Given the expected future evolution of the grid to include more distributed energy resources (DERs), the ability to add smaller, incremental capacity to manage demand growth risk would offer value to a utility’s customer base.

3. KEY ECONOMIC DRIVERS OF SMRs:

Critical to the success of SMRs is their economics. The following section explores some of the key economic drivers of SMRs and how these drivers might affect an SMR's costs differently than when compared to a large reactor.

3.1 Capital Costs

Work by Kessides & Kuznetsov, (2012) provides a useful framework for assessing factors that may affect SMRs capital costs relative to a large reactor. The section below describes these factors in more detail.

3.1.1 Factors Potentially Increasing SMRs Capital Cost relative to a Large Reactor

- **Unit-Level economies of scale:** SMRs could face a loss of unit-level economies of scale due to their smaller size. Economists and engineers have traditionally viewed nuclear reactor costs as governed by economies of scale, whereby the unit cost of the plant (in $/kW) decreases with larger plant size. Due to very low fuel costs, this has been the approach to reducing the energy cost from nuclear plants. Fixed costs that do not scale proportionately with size drive these economies of scale. SMRs would require spreading these fixed costs over fewer units of installed capacity, resulting in a greater cost per unit than a comparable large reactor.

  The impact of this factor on SMR costs would require a detailed component-by-component assessment for a given SMR design. Applying scaling factors to some cost components assumes identical designs across which the component sizes are then varied. Thus, it may not make sense to use scaling factors to cost certain components of SMRs, which will have dramatically different designs and may require proportionately less materials and equipment requirements, than a traditional large reactor. At the same time, some nuclear costs, such as project development and regulatory costs, are likely similar irrespective of the design, and so we would not expect these cost components to necessarily scale down in proportion to the size of smaller reactors.

3.1.2 Factors Potentially Decreasing SMRs Capital Cost relative to a Large Reactor

Other factors could potentially offset this loss of unit-level economies of scale.

- **Modularity***:* Building multiple stand-alone units in sequence on a site could enable cost savings in construction. Engineering-Procurement-Construction (EPC) firms can apply the lessons learned from constructing the first “module” to subsequent modules.
- **Improved Construction Schedule:** The pre-fabrication and standardization of SMR components through factory construction would dramatically reduce construction times, and therefore financing costs incurred during construction**.**
- **Design Simplification:** The simplification of SMR designs may result in lower unit capital costs than a large reactor. An example provided by the Nuclear Energy Agency (NEA) is how Russian marine drive reactors have achieved economies in materials due to a more compact steam supply system (NEA, 2011).
- **Economics of Multiples***:* Serial production of reactors in a factory setting could drive efficiencies to lower costs and would promote learning-by-doing (LBD)[3], whereby cost declines over time occur from repetition of a task. The ability to produce SMRs in a factory setting could enable SMRs to benefit more from LBD than large reactors.
- **Unit timing:** Project developers can add SMRs to a site in increments. While not necessarily a factor that directly influences capital cost, this feature would help meet increasing power demand while avoiding grid instability problems for jurisdictions with small grids. It could also improve the financing of SMRs, as the recouping of revenues can begin upon completing the first module.

3.2 Operations & Maintenance (O&M) and Fuel Cost Considerations

Depending on the design and application, O&M and fuel costs may be higher or lower when compared to a large reactor. For example, SMR designs for remote operation may have infrequent refuelling, which could result in lower labour costs. Design standardization and learning from operations would further reduce costs. Decommissioning and long-term nuclear waste (LLW, ILW, and high-level) management costs may also vary between SMR-types. On the other hand, many O&M cost elements, for example, the minimum on-site security requirement, tend not to scale proportionately with size, meaning higher O&M costs relative to large reactors. Technical solutions to the above problems exist; however, their impact on

[3]There is a wide body of literature discussing the impact of learning rates on the cost of various energy technologies. Please see McDonald & Schrattenholzer, 2001 and Rubin, Azevedo, Jaramillo, & Yeh, 2015 as examples.

cost would depend on the interface between technology on the one hand, and institutional/regulatory considerations on the other.

3.3 Remote Location Considerations

Building an SMR in a remote location, for either a community or industrial process, may have unique design and economic considerations. Building in remote and Northern environments will likely incur higher labour costs, additional transport costs, costs associated with providing a base camp for workers, and additional costs on specialized materials/machinery that can withstand those conditions. This challenge of building in Northern conditions, however, is also a challenge for other forms of energy, not just nuclear. On the other hand, the prospect of SMRs to provide high quality steam for remote locations as cogeneration would benefit their economics.

3.4 Capital Structure & Ownership Model

The amount of upfront capital for a SMR is less than that of a large SMR- for example, ~$2BN vs. $7-$10BN respectively for a 300MWe vs 1000MWe reactor. This means SMRs should fall within the capital budgets of more developers and be easier to fund compared to a large reactor. Regulated entities and projects with off-take agreements have more ability to optimize capital structure to minimize overall project costs. Entities that can benefit from lower taxes or are tax exempt can further reduce overall project costs. The following policy tools could assist the economics of SMRs:

- **Power Purchase Agreement (PPA):** A long-term PPA contracted with a credit worthy counterparty can lower the LCOE of an SMR by decreasing its cost of capital and provide revenue certainty
- **Tax Credit**: A similar incentive to the Production Tax Credit (PTC), used in US markets, could lower the LCOE for SMRs deployed;
- **Loan Guarantee (LG)**: Due to the uncertainties surrounding both First-of-a-Kind (FOAK) SMR technology and project execution/operation, early projects would benefit from a loan guarantee, resulting in lower financing costs, and;
- **Other incentives**: Carbon/zero-emission credits, renewable energy credits (RECs) and credit for providing grid reliability are other examples of cost reducing policy tools.

3.5 Regulatory and Legal framework

Uncertainty surrounding the outcomes of the Environmental Assessment and Regulatory Licensing for nuclear projects adds further risk to increasing the total financing cost of the project if projects are delayed in either of these highly technical and public processes.

There are multiple stakeholders roles and responsibilities towards Regulatory Readiness as follows:

- Vendors (Industry issues with lack of relevant Canadian Standards, such as CSA)
- CNSC Regulatory Readiness (CNSC readiness to assess novel technologies and associated deployment strategies)
- Applicant Readiness for Licensing (Technology readiness of proposed designs, Readiness for conduct of EAs, conduct of construction, commissioning and operation of novel technologies)
- Industry or Government Readiness (infrastructure, supply chain, government policy and organizations in place etc.)
- Public and Indigenous engagement in the process

With proper Stakeholder preparation including meaningful Public and Indigenous engagement before entering the EA and Licensing process and culminating in the CNSC Commission Public Hearing process, this risk can be reasonably mitigated.

The CNSC has put in place measures to provide clarity and minimize regulatory uncertainties. This includes pre-licensing vendor design reviews, which include consideration of designs made in a context where relevant Canadian standards are not available. It also includes provisions for pre-licensing discussions with a potential applicants to provide early feedback on deployment and operational models.

Risks to overall financing costs for SMRs entering the EA and Licensing process may also come from the following:

- Vendor readiness with suppliers and R&D activities to support the engineering design activities and ultimately support the safety case.
- Selected novel deployment strategies
- Transportation
- FOAK novel technology applications

CNSC has implemented pre-licensing engagement processes with vendors and applicants to provide early clarity of expectations.

A pan-Canadian approach for SMRs, with clear and concise industry requirements and regulatory guidelines governing SMR technology, safety, operation and deployment, could significantly reduce uncertainty and overall project costs.

3.6 Literature Review

The EFWG's reviewed the extant literature on SMR economics (see Appendix A for the full review), which identified factors such as **unit level economies of scale**, **dynamic cost trends** (amount by which unit costs decline with construction of additional units; a factor of economies of multiples), **design simplification,** and **co-siting benefits** from SMRs as key drivers for cost. Overall, analysts expect a first-commercial SMR to cost more than subsequent units. However, the literature also showed that capital costs per unit of installed capacity for a mature, on-grid SMRs could be less expensive than that of a Large Nuclear Power Plant (LNPP). Generally, while LNPPs derive greater benefits from economies of scale than SMRs, SMRs have the potential to overcome this cost disadvantage through their own advantages as mentioned above: modularity, economies of multiples, design simplification, and potentially improved construction schedules.

4. LEVELIZED COST OF ELECTRICITY ASSESSMENT

The EFWG's assessment for this activity consisted of two parts:

PART I: Analysis to estimate a range of levelized cost of electricity (LCOE) for a commercially mature SMR to compare with relevant benchmarks. This was a first-order calculation to determine whether SMRs have merit as an economic source of electricity generation relative to alternatives.

PART II: Analysis to determine the most effective policy and partnership tools to entice first-movers to invest in early-commercial SMR projects, with an aim to spur an SMR market in Canada.

A detailed description of our input assumptions, and the sources for our input values, are available in Appendix B. The consensus of the EFWG is that there is high uncertainty surrounding the costs for both a first-commercial and commercially mature SMRs. Cost estimates are indicative until the industry begins building SMR projects with verifiable cost data. It is the stance of the working group that the sources of cost estimates described in Appendix B can provide useful order of magnitude cost estimates to ascertain the merit of SMRs relative to alternative electricity generation options.

4.1 Economic Assessment: PART I- BENCHMARKING

The key finding from this section is that SMRs can be competitive relative to the benchmarks in key applications. Given their merit as a low-cost source of clean electricity that can also de-carbonize heavy industry, mining, and improve living conditions in remote northern communities, government and industry should support this promising technology for it to overcome its initial barriers to market. Support from government is necessary, as the private sector alone can not fund the requisite early stage Research, Development, and Demonstration (RD&D) investments for SMRs to achieve commercial maturity without some commitment to market success.

Key Finding: *SMRs can be competitive relative to benchmarks in key applications. Their economic merit justifies government and industry support for this promising technology.*

4.1.1 Choice of Benchmarks and Benchmark Scenarios

Table 1 below provides the SMR application and the corresponding benchmark in which we compare SMR costs. The applications are the ones described in sections 1 and 2 as the most promising early markets for SMRs. They are not exhaustive, however, as SMRs can potentially provide power and high-quality steam to many industrial applications such as chemicals or petroleum refining. However, we deemed an analysis of the applicability of SMRs to these other heavy industry sectors as out of scope given the timelines for this report.

Before most SMRs can become commercially viable, the EFWG expects several years of necessary R&D, licensing, and demonstration. Thus, the economic comparison assumes an in-service date of 2030.

Table 1: SMR Application with Corresponding Benchmarks

Application	Benchmark
On-Grid	Natural Gas Combined-Cycle, Wind, Large Hydro, Run-of-River Hydro, Natural Gas Combined Cycle with CCS
Remote Off-Grid Communities	Diesel (barge and flied-in); Small Hydro;
Mines	Diesel
Oil Sands	Natural Gas Cogeneration

For on-grid baseload power, the main competitor for SMRs under prevailing market conditions are combined cycle gas turbines (CCGT) powered by natural gas. Given the strong business case for CCGTs, some Canadian jurisdictions are considering gas to replace coal to meet the mandatory phase out of coal by 2030 under the 2016 Pan-Canadian Framework. However, while natural gas provides a lower-emitting (approximately half as much as coal) and inexpensive option relative to coal, it is still a source of significant GHG emissions and can only provide a partial de-carbonization of the energy system. Future increases in the price of carbon poses a risk to the economics of natural gas for electricity generation. Furthermore, while gas prices are currently low, they have been historically volatile and so price variability is another risk. Finally, the cost of natural gas is heterogeneous across Canada, with significantly higher gas prices in some regions. We explore the implications of these factors on natural gas prices in our LCOE analysis.

We included other non-emitting sources as benchmarks. A utility can couple CCGT with carbon capture and storage (CCS) to reduce emissions by ~90% from a baseline CCGT plant. Despite technological advances in this area, there are currently no commercially operating CCGT facilities with CCS – although there are pilot projects being tested, such as the 50 MWe Net Fuel Oxy-fired Capture Plant in Texas (arsTECHNICA, 2018). This technology could potentially compete with SMRs as a source of clean, firm capacity.

Another source of clean, firm capacity that could compete with SMRs is the expansion of Canada's already sizeable hydroelectric fleet. The economics of hydro generation, however, are highly site-specific. While the traditional hydro jurisdictions of British Columbia, Manitoba, and Quebec can economically expand their hydro capacity to meet increasing demand on their grid, the results that follow show it is not necessarily the case for jurisdictions lacking abundant and cheap hydropower.

We also included intermittent resources, such as onshore wind and run-of-river hydro. Being intermittent, their comparison to firm capacity sources of generation is not an apples-to-apples comparison, due to intermittent sources being less reliable than firm capacity in producing electricity when needed. We excluded utility-scale Solar PV, another potential source of intermittent renewable, from this analysis due to its marginal uptake in Canada to date, and its economics currently being less favourable relative to wind. Modelling projections of the Canadian electricity system, with detailed spatial and temporal representation of wind and solar resources, have found wind to outcompete solar for de-carbonizing Canadian electricity (Dolter and Rivers, 2018). At the same time, assumptions around solar's continued declining cost trend could reverse its competitive position to wind by 2030.

In either case, an apples-to-apples LCOE estimate would see intermittent renewable coupled with a form of energy storage. This is because LCOE calculations do not capture the value of the electricity produced from the competing sources (Joskow, 2011; Borenstein, 2012). Based on current utility scale battery costs of $1,450-$2,500/KW (EIA, 2018; Lazard, 2017a), and assuming battery replacement every 10 years (one replacement for a wind project with 20 year life), the cost of battery storage would add an additional $33-$55/MWh to the cost of wind. What these costs estimates would look like in 2030 is very uncertain. Battery storage is, however, currently one of the costlier options for adding flexibility to the grid, and options to increase intermittent renewable penetration that might be cheaper include adding transmission lines, pumped-hydro storage, demand-side flexibility, and compressed-air-storage. SMRs, through molten salts, can provide storage capability to complement intermittent renewables.

The extent to which relatively cheap sources of grid-flexibility can increase intermittent renewable penetration is an area of active debate currently among energy analysts. The EFWG chose to sidestep the debate slightly by presenting the LCOE of intermittent wind *without* any additional storage costs in the analysis that follows. However, keep in mind these considerations surrounding cost of flexibility and "firming" of intermittent sources when interpreting our findings.

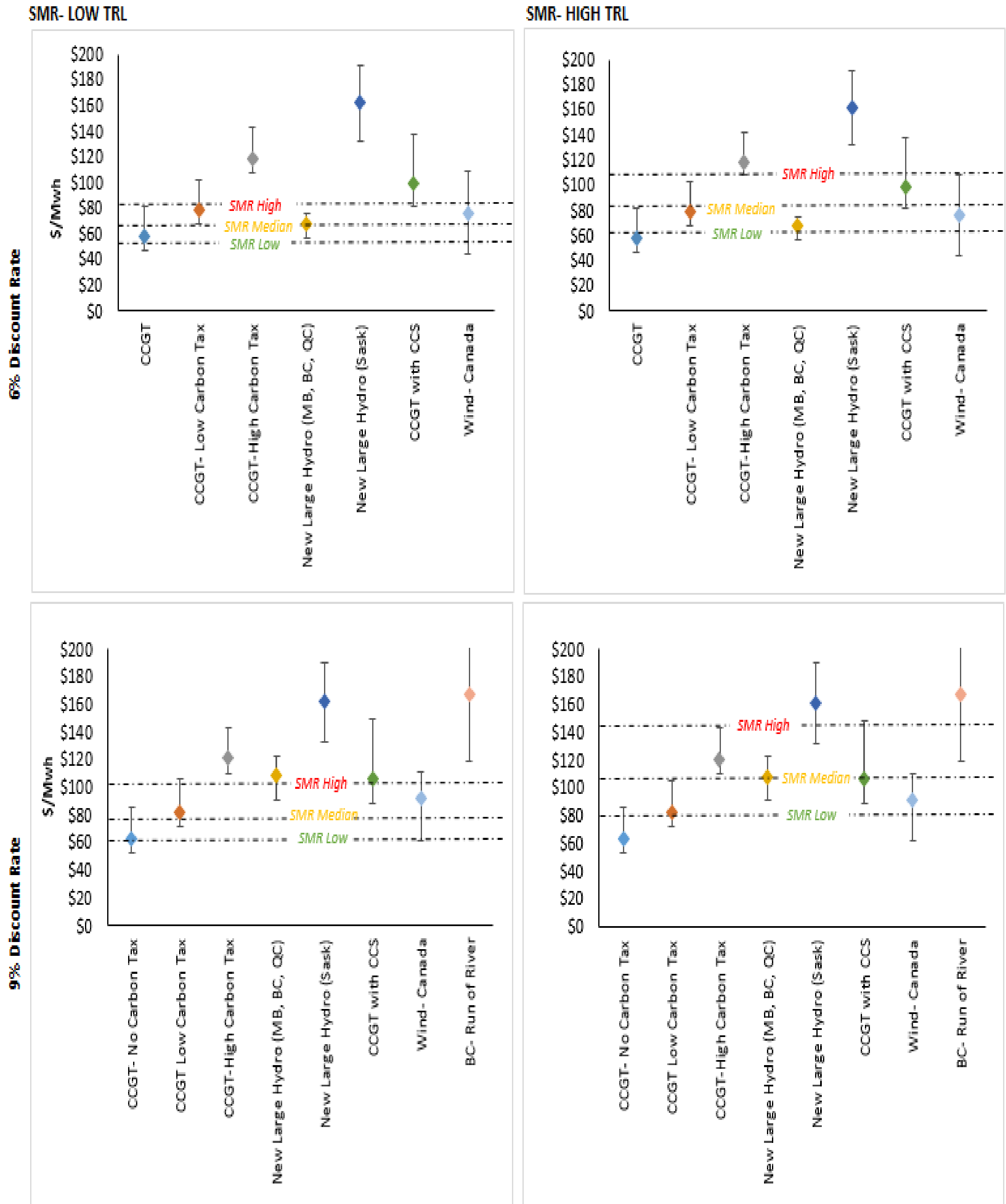
For remote off-grid communities and mines, diesel generators are the current incumbent technology; and thus, the obvious choice of benchmark. We provided separate diesel costs for communities where the diesel is barged-in by boat vs. where it is flown-in by plane. Costs for the latter are significantly higher than the former. Data on other potential competitors to diesel for Northern and remote applications is scarce; however, we obtained some preliminary cost-estimates for small hydro projects in Iqaluit, as well as for other Northern jurisdictions (Knight Piesold Consulting, 2006; Government of the Northwest Territories, 2015). Another potential competitor to SMRs for off-grid locations were wind/solar-diesel-battery storage hybrid systems, which have shown strong economics in southern latitudes (see ABB, 2017 for an example). However, uncertainties around the cost of batteries discussed above, and the capacity factors for intermittent renewables in northern climates, precluded their inclusion by the working group.

For oil sands, natural gas cogeneration is the current incumbent technology. Alberta Innovates recently conducted an in-depth assessment of the economics of SMRs for the oil sands, in conjunction with PNNL (Short & Schmitt, 2018). We drew heavily from their report in our economic assessment of SMRs for this market segment.

4.1.2 On-Grid

Figure 1 below illustrates our LCOE calculations for a commercially mature SMR relative to on-grid benchmarks for 2030. Appendix C provides assumptions and sources for the input parameters for the SMR and benchmark costs. The LCOE ranges represent a median, high, and low scenario. Calculations for each scenario's LCOE used both the 9% and 6% discount rates, showing the importance of the cost of capital in driving the results. The EFWG provided costs for two types of SMRs, those which are evolutionary from the current large reactor designs, and thus have higher TRL, as well as those for more advanced, lower TRL designs.

Figure 1: Comparison of SMR LCOE to Benchmarks- On Grid



*The low and high carbon price average $60/tonne and $170/tonne respectively over the lifetime of the technology. See Appendix B for the carbon price trajectories

Several key findings emerge from the above figure:

- At all cases, SMRs could be competitive on a LCOE basis to relevant benchmarks
- Competitiveness at the 9% rate with natural gas CCGT depends on projections of the gas price and carbon price. Assuming no carbon price, Low-TRL SMR deigns under our most favourable O&M and capital cost scenario can be competitive with gas when the gas price exceeds $6.5/GJ. At a high carbon price, however, all but one SMR scenario are competitive with natural gas at any gas price examined
- Lowering the cost-of-capital from a 9% to a 6% discount rate dramatically improves the economics of SMRs. At that cost of capital, not only does it approach natural gas, but it also is the most economic non-emitting generation option alongside large hydro in favourable hydro jurisdictions and wind in certain favourable sites.
- Costs for the low-TRL SMR designs appear much lower than for High-TRL designs. At the 6% discount rate, these low-TRL technologies become the least cost generation option. However, data underlying these costs calculations mostly comes from vendor claims about these technologies, which are further out in terms of commercial deployment and thus more uncertain. As a counterpoint, vendors for these advanced designs argue that they possess disruptive technologies that could reduce costs beyond what the evolutionary designs are capable, and that the cost figures they provide reflect this techno-economic potential.

The above figure masks the fact that natural gas prices vary considerably by province due to proximity to gas wells and infrastructure constraints (prevalence of requisite pipelines). Thus, for some Canadian jurisdictions, natural gas generation is prohibitively expensive. Table 2 below illustrates the current range of natural gas prices by province. Alongside these prices are the range of gas prices that provinces could be facing in 2030 based on the projected growth in gas prices between 2018 and 2030. A key finding from this table is that SMRs are competitive with gas in the Maritimes and Eastern Canada at today's gas price, let alone what the price of gas may be in 12 years time.

Table 2: Current Range of Natural Gas Prices by Province and Potential Range in 2030.

Province	2018 Natural Gas Prices $/GJ	2030 Natural Gas Prices $/GJ ($2018)
Canada (average)	3.86	5.61
Nova Scotia	7.69	11.21
New Brunswick	6.46	9.41
Quebec	7.00	10.19
Ontario	7.04	10.26
Manitoba	2.84	4.14
Saskatchewan	2.65	3.86
Alberta	2.70	3.93
British Columbia	2.80	4.08

Source: 2018 Natural Gas prices by province from CANADIAN ENERGY RESEARCH INSTITUTE, 2018

Furthermore, the ranges of levelized costs of electricity for wind in Figure 1 reflect projects from various regions across North America. There are other salient reference points, however, including a specific recent experience in Alberta that saw an average price of $37 per MWh for wind projects selected in an auction for 600 MWe (Alberta Electricity Systems Operator, 2017).

4.1.3 Off-Grid – Communities and Mines

Modelling the costs for an off-grid SMR required a different approach than for assessing on-grid costs as there is no strong literature basis to assess SMR costs for these categories. Only certain vendors have made their estimates publicly available (see Wallenius, Szakalos, Ejenstam, & Klomp, 2015) , and where they have, we only found costs on a levelized cost basis without a break out of the capital, O&M, and fuel cost assumptions driving the LCOE calculation. Appendix D provides assumptions and sources for the input parameters for the SMR and benchmark costs for the off-grid segment.

Therefore, we conducted our own techno-economic assessment to model costs based on key economic drivers identified previously. We provide a description of our method in Appendix B. We modelled three sizes of SMRs, a 3 MWe SMR for a mid-sized Northern Community, a 10 MWe SMR representing a large Northern Community (Iqualuit or Norman Wells as examples) or the demands of a small mine, and a 20 MWe reactor representing a mid-sized mine.

Our LCOE results for these sizes are located in Figures 2 and 3 below. Where possible, we provided our estimates alongside vendor levelized cost claims for the different SMR sizes. Generally, our LCOE results are comparable to these vendor values.

Figure 2: Comparison of SMR LCOE to Benchmarks - Off Grid

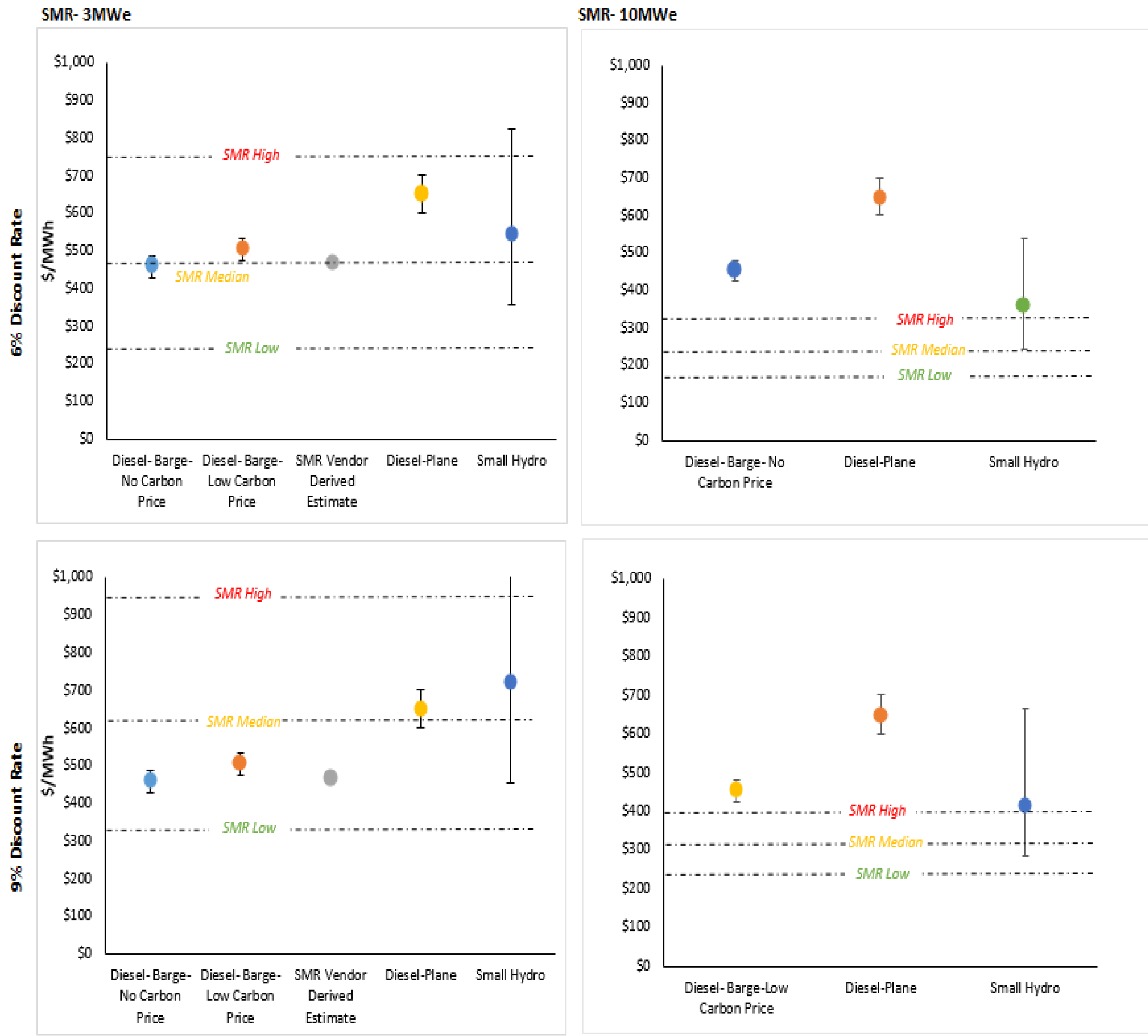
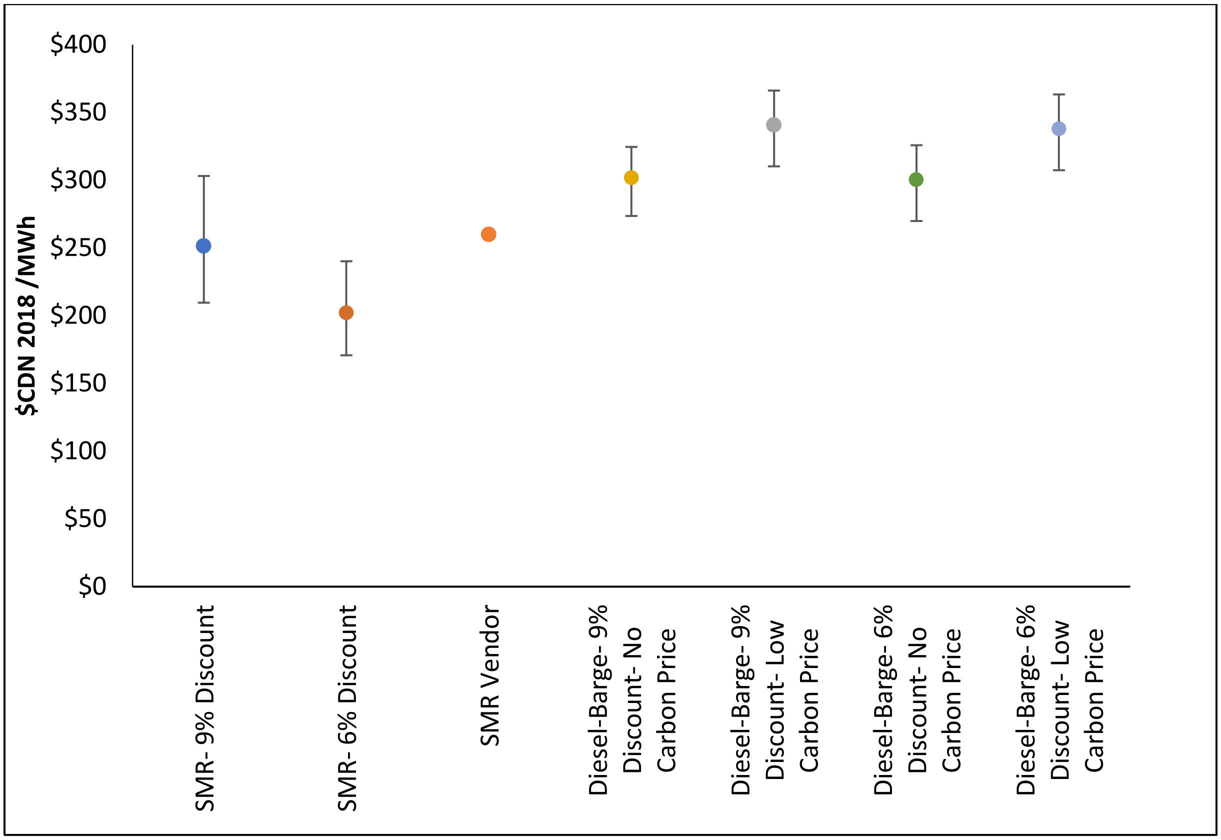


Figure 3: Comparison of SMR LCOE to Benchmarks- Off Grid Mine (20 MWe)



Key findings from the above figures are as follows:

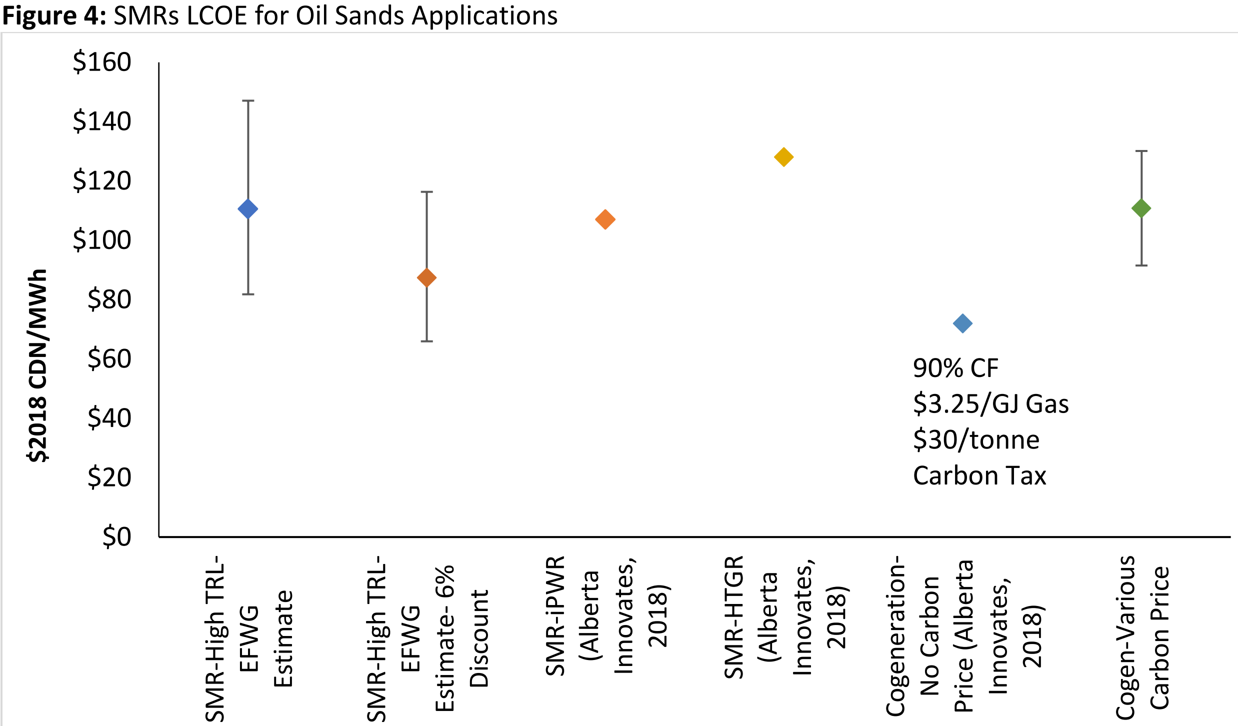
- SMRs **can be competitive** in all segments examined
- Like for on-grid, the SMR LCOEs for off-grid applications are very sensitive to the cost of capital
- LCOE results are also highly sensitive to development cost and scale-independent O&M factors (staffing, insurance premiums, licencing renewal costs)– making up much of the variation. The larger the SMR, the less impact due to the ability to spread these cost over larger capacity. These costs also explain the major difference in LCOE for SMR between the 3 sizes.
- A key finding from figure 3 is how for a 3 MWe SMR, these size-independent fixed costs can make or break the competitiveness of this size reactor vs diesel, and risks making the SMR uncompetitive at that size. At the same time, measures that can lower the cost of capital can mitigate some of this risk.
- The potential for SMRs to cogenerate heat and power for communities, although not factored into the calculations here, could improve their economics further relative to diesel. This possibility is discussed further in the following section when discussing heavy industry

4.1.4 High quality steam and heat for industrial processes (i.e. oilsands and bitumen refining)

Although SMRs have the capability to produce large quantities of electric energy, they may be even more efficient in providing high quality steam or heat for industrial processes. Unlike other non-emitting resources, SMRs can displace traditional sources of energy such as gas, diesel or coal to generate the high temperatures needed to produce steam or heat for industrial process requirements. One example of an application is the use of SMRs to displace combined heat and power for both surface mining and steam-assisted gravity drainage (SAGD) industrial operations as part of the oil sands refinement process. For example, approximately 90% of the GHG emissions that come from the SAGD process is due to burning natural gas to produce high quality steam. SMRs therefore demonstrate a potential to enter a new large domestic market and if successful, access to an international market for other such industrial processes.

In 2018 Alberta Innovates, conducted a techno-economic analysis of the potential for SMRs in the oil sands (Short & Schmitt, 2018). Overall, they found SMRs were generally not competitive relative to the cogeneration baseline, even when the latter is subject to a small carbon tax. However, carbon pricing, at levels seen in the low and high carbon price scenarios used in this report, would improve the competitiveness of SMRs for the oil sands considerably. Figure 4 below demonstrates this by supplementing the Alberta Innovates analysis with some of the LCOE estimates from the EFWG's analysis.

Figure 4: SMRs LCOE for Oil Sands Applications



4.2 Economic Assessment: PART II- ECONOMIC & POLICY ROADMAP

Using a financial cash-flow model, the EFWG mapped out a path whereby a combination of policy, institutions, and partnerships could share-risk and drive-down the cost of a first-commercial unit, making it equivalent to the expected cost of a mature SMR, as calculated in PART I. The EFWG expects the cost of SMRs, upon technical and commercial maturity, to be considerably lower than the first SMR deployed. Based on the precedent of other energy technologies, particularly those technologies with features of modularization and factory construction, successive units after the first will see costs decline due to learning-by-doing, standardization, and economies of multiples. We also expect costs to decline immediately after the first unit, as subsequent units will no longer need to incur one-time costs such as first-of-a-kind engineering and while financing for SMRs improve.

However, the first commercial SMR, in all likelihood, will face a cost premium, and so we wanted to show how policy and risk-sharing mechanisms could entice action on the part of a first-mover to invest despite its higher cost. Otherwise, there is very little incentive for an investor to be “first” given the expectation that the technology will be cheaper later. This conclusion led the Working Group to consider the question of which government policy measures would be most effective in driving down FOAK costs.

4.2.1 Drivers of levelized cost of energy (LCOE) for SMRs

For the EFWG to choose the best policy levers, a requisite first step was to identify the key economic drivers of an on-grid First-of-A-Kind (FOAK) SMR. The top influencers of SMR economics is the cost of capital, capital costs and construction time as illustrated in figure 5:

Figure 5: Tornado diagram illustrating cost drivers of SMRS. The figure shows the base case LCOE of $163 for an on-grid FOAK SMR. As shown, by applying different sensitivities to the base case you can see the impact resulting in min and max LCOEs. The sensitivities analyzed include cost of capital, capital costs, construction time, economic life and O&M costs.

The cost of capital, the percent by which project cash flows are discounted, is the single largest cost driver impacting SMRs. The cost of capital represents the project's risk, factoring in mechanisms to share and mitigate that risk. Areas of risks identified include debt repayment, project schedule, first of a kind commercial deployment, upfront development costs, waste disposal, decommissioning, and operations risk. The federal and provincial governments should, in partnership with industry, investigate ways to best risk-share through policy mechanisms to reduce the cost of capital. This is especially true for the first units deployed, which would likely have a substantially higher cost of capital than a commercially mature SMR.

Recommendation:
Government to commit to reduce the cost of capital for SMRs

Capital costs are the second most influential economic driver of SMRs. Analysts expect the capital cost for a FOAK SMR to be much higher due to first of kind engineering, tooling and design as well as increased project contingency for construction estimates. Over time these capital costs will decrease as per a learning rate. Based on literature, learning could reduce the overall initial capital costs of a SMR by approximately 5% – 30%[4] per doubling of cumulative

Recommendation:
Industry, in partnership with government, to lower the capital costs of SMRs through learning-by-doing and applying a fleet approach

[4] Based on a historic range seen from other energy technologies.

installed capacity, or about 15% to 55% in total (NEA and OECD, 2011). The greater the fraction of standardized, modularized and pre-fabricated SMR components through centrally located manufacturing, the greater the expected reduction in capital costs. Industry and governments should focus efforts and design criteria with these deployment and construction elements in mind. In addition, government has a role to start the learning process by co-funding demonstrations of the technology.

Lastly, construction time is a significant economic driver of SMRs. Stakeholders in some of the markets identified require SMRs to have a project schedule of 6 years or less. In addition, as the MW size of a SMR decreases - project schedule, and costs associated with development and licensing, become increasingly important. Longer project schedules also magnify the risk of cost and schedule overruns. Governments and industry should focus on designs which can reach commercial operation within a 5-year timeframe, and provide performance-based incentives for SMRs that achieve this target. Performance-based incentives could include additional risk-sharing and/or cost sharing upon achieving a timing objective.

Recommendation:
Industry, in partnership with government, to consider performance-based incentives for SMR deployment

4.2.2 Policy Roadmap for SMRs-On Grid Market

As illustrated in figure 6 and 7, we applied different policy and risk-sharing assumptions to bring down the cost of a FOAK SMR. The graph below provides indicative pricing of both a FOAK and commercially mature on-grid SMR. An on-grid SMR is expected to reach commercial maturity by 2030 and is compared to its most economic alternative, a natural gas combined cycle (NGCC) benchmark. Input assumptions for the following bridge diagrams are found in Appendix E.

Figure 6: A bridge diagram showing the path towards reducing the costs of a FOAK reactor. Each yellow section represents the magnitude of each risk-sharing or policy mechanisms impact to a FOAK's LCOE. This

is then compared to a commercially mature SMR, with expected deployment in 2030 and compared to the alternative economic benchmark. Carbon costs in 2030 are presented as a range.

Estimated cost reductions from first SMR to commercial deployment

In this illustration we start with our base case assumptions for FOAK on-grid, after which we apply each key economic driver as a sensitivity to isolate the magnitude of its impact to SMR deployment. The key economic drivers include:

Development time and pre-construction costs (Dev. Time):

Development time can substantially impact the market demand and risk of a SMR. Industry has indicated that a SMR should be modular in construction, deployable, and standardized with limited unique parts. If not adhered to, the risk of construction overrun is greater, reducing an SMRs market applicability and demand. Industry has indicated that, keeping the total project schedule to 6 years or less from development to Commercial Operation Date (COD) would be highly desirable.

Pre-construction costs for development become material as reactor size decreases. Research suggests pre-construction costs, independent of size, can be over $100M. This would be a substantial risk for a new on-grid entrant to take on, and may require cost-sharing for new entrant utilities to get comfortable with the risks of deploying a FOAK SMR on their site. As shown in fig. 6 the relative impact to the LCOE by reducing the project schedule from 9 to 6 years is small but the schedule reduction substantially de-risks the project and expands its market applicability and demand.

Cost of capital (LG/Reg. rate)

The cost of capital or weighted average cost of capital (WACC), is the single greatest economic driver impacting the achieved LCOE. For a FOAK reactor financed with 100% equity at a 10% cost of equity[5], and Thus, a 10% WACC, the corresponding LCOE would be $159/MWh. Leveraging of the project with 55% debt, as would be more realistic for a utility-financed venture, would substantially reduce the cost of capital. Lowering the cost of capital further are risk-sharing measures by the Federal Government, such as a Loan Guarantee (LG), which would guarantee repayment of the debt in an event of default, or ownership by a regulated utility with experience in nuclear operations, such as Ontario Power Generation, lowering the regulated cost of equity to 8.78%.

The combination of these factors could reduce the cost of capital (WACC) from an initial 10.0% to 6.15%. The important point is the net impact of using both debt and a regulated cost of equity. As shown in fig. 6, this reduces the LCOE by 33%- from $163 to $109- illustrating how stakeholders and government can efficiently risk-share the project to make it more cost competitive.

Accelerated CCA and corporate/investor tax credits (Corp. CCA)

Currently, nuclear projects use a Capital Cost Allowance (CCA) schedule that approximates that of long-lasting assets such as hydroelectric. By accelerating its CCA, and optimizing the tax benefit to the corporate balance sheet (instead of as a standalone project), an SMR can reduce its LCOE by 2%. Since the benefit is to a corporation, we modelled the ACCA benefit using a corporation's marginal tax rate of 25%. Its impact could be greater by applying those tax credits to a higher marginal tax bracket, such as those of an individual investor.

Commercially mature on-grid SMRs and the benchmarked alternative

With greater deployment, the LCOE for SMRs will stabilize and achieve cost competitiveness against the benchmark. The bars furthest to the right of figure 6 compare such a commercially-mature SMR to the on-grid NGCC benchmark. As this figure shows, we expect mature SMRs to be in the cost range of natural gas, especially in a carbon constrained world where SMRs are anticipated to be a cost-effective option to mitigate CO_2. In addition, innovative vendor designs which significantly cut costs through passive safety features and standardization estimate that SMRs could be competitive with natural gas without carbon

[5] A 10% return on equity was based on the average approved regulated cost of equity from Canadian and U.S. gas and electric utilities (Edison Electric Institute, 2017; Ontario Energy Board, 2017).

pricing. Further research, and actual pilot and demonstration projects, are needed to validate such claims made by vendors.

4.2.3 Policy Roadmap for SMRs- Other Markets

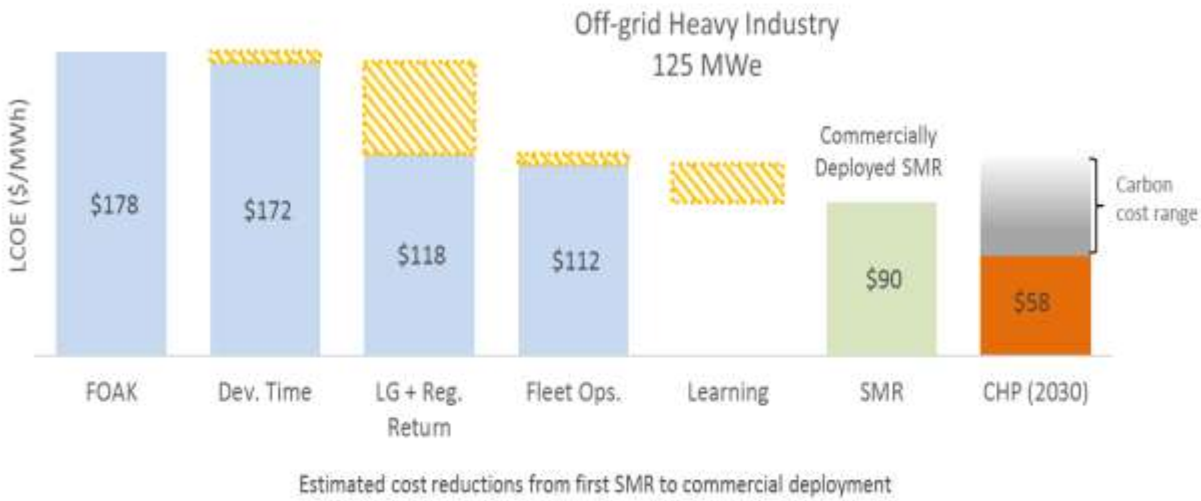
Other SMR designs for market applications such as heavy industry, mining and remote communities are less mature and require significantly more due diligence and development time before deployment. These industries could be eventual adopters of a proven SMR technology, but are likely unwilling to commit financially to assist their development. Developing these markets require stakeholder involvement, identification of user needs, and investigation of risk-sharing and business partnerships. The user requirements should drive the applicable SMR designs for development and markets should explore business relationships for first commercial deployment.

Heavy industry, such as oil sands mining could benefit from SMRs to offset large quantities of CO_2 while providing low cost heat and electricity. In addition, the EFWG expects SMRs for remote mining to cost less than diesel for electricity generation. For this study, we conducted financial analysis for two ranges of SMRs, 125 MWe for heavy industrial processes (including for steam) and 20 MWe for remote mining. A bridge diagram for these smaller reactors, like the one in figure 6, is repurposed in figures 7 and 8 for the oil sands and remote mining respectively.

Heavy Industry

In Figure 7, we compare SMR costs for the oil sands to the most economic competitor, which is natural gas co-generation of heat and power (CHP). As shown, reducing development time and pre-construction cost is slightly more impactful with overall the same key economic drivers as for on-grid. In this scenario, we expect the heavy industry SMR to be cost competitive to a CHP with a price, or constraint, on carbon.

Figure 8: A bridge diagram for heavy industry shows similar impacts to the LCOE given different risk-sharing and policy mechanisms. Added is a new category, Fleet Ops., which becomes more significant as reactor size decreases. A commercially deployed SMR is forecasted to be competitive to the CHP benchmark given a price on carbon.



Fleet Operations (Fleet Ops.)

One of the advantages of building a large conventional nuclear reactor of size 1,000 MWe is that the project can spread the operational, security and insurance costs over a larger revenue base. When reactors reduce in size, the O&M costs associated with them do not necessarily scale down linearly and can become a material cost driver. This is true for SMRs 100 MWe or less, as they will face challenges keeping O&M costs low or comparable to a large reactors benchmark ($/kW-year). Therefore, the EFWG assessed how O&M costs would scale to estimate their economic impact on smaller reactors.

The sensitivities applied in the bridge diagram recognize this impact by showing the net impact of lowering the O&M costs of smaller reactors to the same benchmark cost as large reactors. For these small reactors, that O&M costs become a key economic driver. A suggested way to bring O&M costs down for small reactors is to use a fleet operations approach. Where one central operator is used to operate all of the different SMRs and monitor them on a periodic basis. This would require a rethinking of passive safety design with demonstrations to satisfy the regulators. Since it is unknown which SMR design or designs will be ultimately deployed, it is yet to be determined if such streamlined operations are achievable.

Remote mining applications

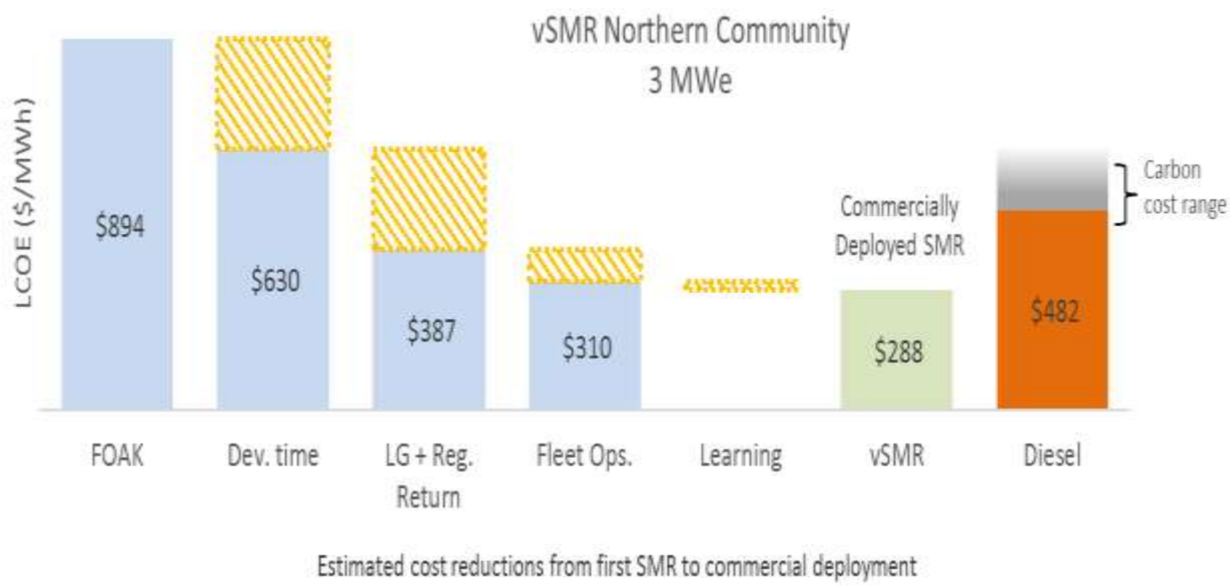
For remote mining applications, our financial analysis shows that SMRs could be very competitive relative to the alternative benchmark diesel, without the need for a price on carbon. However, SMRs for remote mining applications are not without their own challenges. As shown by the bridge diagram, development time and pre-construction cost becomes a key economic driver. Reducing a SMRs project schedule from 9 to 6 years results in an approximate 14% reduction in the overall LCOE. Indeed, industry feedback suggests if SMRs cannot be deployed within 6 years, then they would not be a realistic competitor in this market. Similarly, the operations, staffing and security required for smaller SMRs must be within the same range as large conventional reactors, as shown under Fleet Ops. Large nuclear reactors achieve economies of scale by spreading out fixed operational costs. If a "fleet operations" approach were to be taken, where smaller SMRs in the range of 20 MWe or less, achieved the same staffing level benchmark as a larger reactor ($/kW-year), then this would lead to a substantial decrease in the overall LCOE. In this case a fleet approach to operations, where a team manages multiple reactors at multiple sites, lowers the LCOE by approximately 10%.

Figure 9: A bridge diagram for off-grid mining. Development time and cost becomes a material economic driver and is a requirement from industry to be less than 6 years. We expect a commercially deployed SMR to be competitive to the diesel benchmark without a price on carbon.

Remote communities and vSMRs

For remote community applications, the energy demands of these communities will require SMRs in the 3 MWe or less range. These smaller reactors would almost certainly require a new innovative design for development. In addition, their deployment model will be more constrained when compared to other markets. This is due to the complexities of constructing and operating such plants in remote northern communities. Like SMRs for remote mining applications, project schedule and development costs, as well as fleet operations, become additional key economic drivers. To further reduce costs, several vendors have proposed remote operations, involving a team of individuals who can monitor the operations and conditions of the reactor remotely, spreading operating costs over multiple sites and units. This market will also have other challenges, including seasonal shipping and construction schedules, with will impose additional constraints requiring new technical and project management approaches.

Figure 9: A bridge diagram for a vSMR for remote communities, particularly in the North. The EFWG expects a commercially deployed vSMR to be competitive to the diesel benchmark without a price on carbon.



4.2.4 Policy Roadmap for SMRs- Cross-Cutting Considerations

Fleet economics

A key ingredient for SMR success will be their ability to be both modular and standard in their deployment, and the eventual economics of SMRs relies heavily on the expected cost reductions that these features engender over time. Therefore, a criterion used to prioritize funding for SMRs should be their applicability to a fleet approach, involving the deployment of multiple standardized units of a handful of designs with favourable economics, applicability to end user requirements, and pedigree of technology and operators. Given the large range in user requirements, spanning the three major markets, we foresee a need for more than one SMR design to meet all market applications. That being said, we believe it would not be in the best interest to Canada and its partners to apply a pan-Canada approach where 4 to 5 highly distinct SMR designs are deployed for first commercial operation. This would

Recommendation: *To encourage the formation of a Network, whose membership is representative across energy, manufacturing, science and technology, and in partnership with the government, provide advice and requirements for the release of funding for SMR related projects.*

add additional time to the product development cycle, dilute the Canadian effort and potentially drive costs up by not leveraging central manufacturing with a well-developed and focused supply chain. Since each stakeholder, industry partner and government agency has different needs and requirements, achieving this level of sameness across a fleet of 2 or 3 different SMRs will be a considerable challenge.

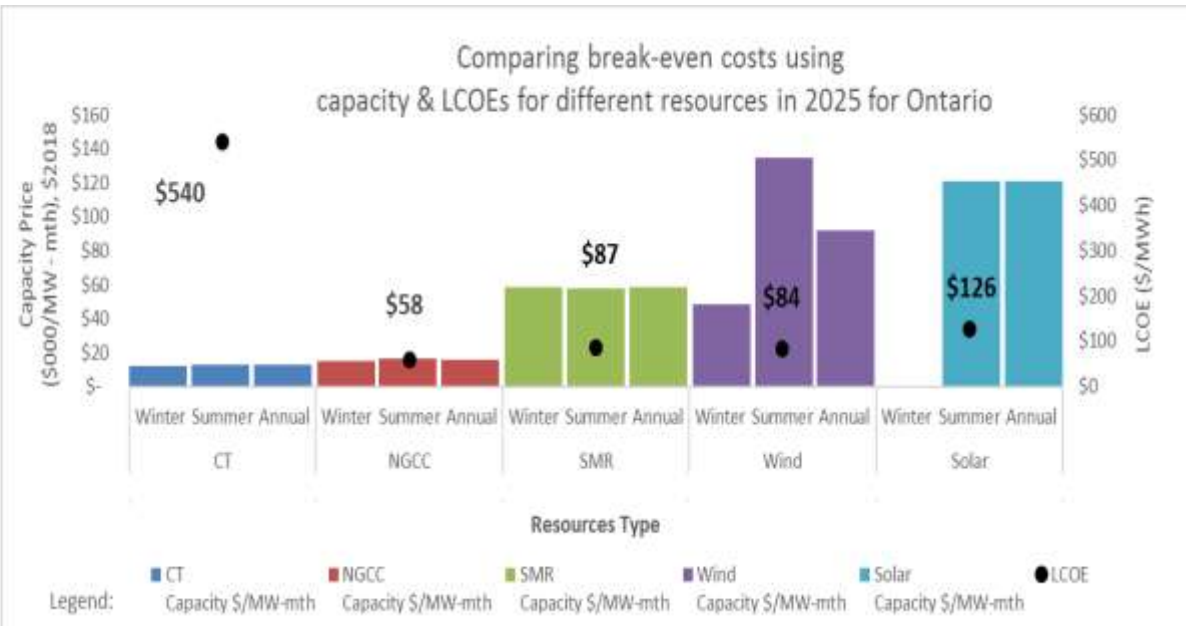
A way to address this challenge is to support the formation of an industry led network in partnership with the government. The network would be composed of key stakeholders and industry partners (users, supply chain, operators, national lab, and interested industrial customers), whose membership could be representative across energy, manufacturing, science and technology. This network can identify needs and timelines for product developments and propose projects for government funding. The network can, in-partnership with the government, provide expert judgement and advise on SMR requirements, depending on the need. This is not dissimilar to the UK's approach for developing SMRs, where sub-sets of expert working groups in the Nuclear Industry Council act as the forum for engagement between the nuclear industry and government.

Although a decision on the exact governance structure of the network is outstanding, pursuing certain principles would increase success. For example, given the uncertain needs of industry at this stage, the network should be flexible enough to change and grow over time. Membership to the network should demonstrate economic commitment and be advantageous for individual members to join. This means incentives for broad alignment to mitigate the risk of independent industry groups developing and manufacturing SMR technology on their own accord.

Other economic considerations

One of the main issues with some types of renewable energy is that they are intermittent, providing little reliability to the grid unless supplemented with energy storage and flexibility type services. Many of the economic comparisons made thus far have only considered the LCOE as the key economic comparator to be cost competitive. Although the cost of energy is important, the total cost to the grid includes its ability to provide capacity during times of high demand from reliable resources. Illustrating and comparing those differences is Figure 10. The LCOEs for five common on-grid resources are provided as black dots. By comparison, the bar graphs show the break-even price that the same resource would need to clear in a capacity market auction to achieve the same amount of annual revenue. For both Combined Cycle (CTs) and NGCC, their required capacity prices are low. This is not surprising, since these resources can ramp up or down quickly and cheaply to meet changes in demand. For SMRs, their expected contribution to peak capacity is flat throughout the year and is considered 90% reliable. For wind and solar, their contribution to peak capacity is significantly lower and differs per season. For example, wind provides far more peaking capacity in the winter then in the summer as a percent of its installed capacity (MWs). Whereas solar provides some peaking capacity in the summer but no capacity in the winter months. Therefore, the required breakeven price to clear the capacity market per MW of installed capacity is significantly higher for intermittent resources, and therefore resulting in higher total costs to operate the grid.

Figure 11: Moving from right to left, the required breakeven capacity price for each different resource increases. As illustrated, the LCOE and capacity prices for SMRs are forecasted to lie somewhere in the middle, being more competitive then renewables and best compared economically to an NGCC. Analysis is based on Ontario resource requirements and assumptions.



Source: Internal OPG analysis; Ontario Independent Electricity Systems Operator, (2018).

5. WHY CANADA?

Canada has been a leader in the nuclear sector since the dawn of the nuclear age after the Second World War. The first nuclear reactor that sustained criticality outside of the United States occurred at Chalk River in 1945 at the Zero Energy Experimental Reactor (ZEEP). Canada's Chalk River Laboratories have been at the forefront of nuclear research and development (R&D) and innovation ever since. Chalk River was the site of Canada's leading research reactor, the National Research Universal (NRU), which was used for a wide range of research, medical and industrial applications since 1957 until its final shutdown in March 2018 after 60 years of exemplary service (Canadian Broadcasting Corporation, 2018). It is also the birthplace of the CANDU reactor, the only non-light water reactor to gain international recognition and be exported from its home country to a range of countries around the globe. In 1987, the CANDU reactor was listed as one of Canada's top ten engineering achievements of the previous 100 years, along with the CN Tower and the Alouette satellite (Canadian Geographic, 2014). Today there are 19 operating CANDU reactors at home (accounting for approximately 16% of the national electricity mix) and operating CANDU reactors in Argentina, Romania, India, Pakistan, Korea and China (Canadian Nuclear Association, 2017).

Even more importantly, the nuclear industry in Canada is vibrant and growing primarily based on the decision in Ontario in 2015 to approve refurbishment of the 4 nuclear units at Darlington and the remaining 6 units at Bruce. This $26 Billion 15-year program has injected new life into the industry and as a result, has bolstered the nuclear workforce and supply chain in Canada. This contrasts with other tier-one nuclear countries, where new build projects have brought the biggest nuclear vendors in the world to the brink of extinction, highlighting the weakness of their supply chains, which have atrophied over the last few decades. Today it is China and Russia that lead the world in new nuclear projects. Canada is one of a few western countries poised to compete with these global giants. However, competition won't be easy. They are both extremely aggressive in pursuing international nuclear business with strong support from their respective governments. The Russian nuclear company, Rosatom, claims to have an order backlog exceeding $100 Billion (Rosatom, 2018).

Furthermore, the Canadian industry's head start over countries such as the US and UK will not last indefinitely. Combined the two countries have recently invested over $CDN 1B in SMRs and are taking measures to revamp their supply chains and improve the capacity of their regulators. If Canada is not prepared to act now, then the Canadian advantage will evaporate. It **is** a considerable advantage, though, one for which Canadians should be proud. Canada's nuclear industry covers the full range of nuclear expertise, from R&D to uranium mining and fuel fabrication, reactor design, plant construction, maintenance, waste management and decommissioning. Canada is also the world's second largest uranium producer, with the world's richest high-grade uranium ores located in Saskatchewan. Canadian reactors rely exclusively on domestic uranium. In 2017, 88% of Saskatchewan's uranium is exported to support nuclear power generation in other countries helping to reduce carbon emissions around the world (Natural Resources Canada, 2018).

As the world nuclear industry realigns, Canada has the potential to play a leadership role in the upcoming technology of SMRs. The current strength of Canada's world-renowned nuclear industry and the potential for a strong domestic market makes Canada an excellent place to invest in this new technology, which a wide range of vendors competing to be first movers will be unlikely to find in other countries. First, Canada has remote communities and a resource sector spread across a vast geography, together with its smaller cities provide the need for SMRS in three market segments: on-grid, heavy industry (mining and oil sands) and off-grid remote communities.

Canada maintains key advantages across the nuclear supply chain. A key strategic advantage is with Chalk River Laboratories, which has an interest to use their site to locate demonstration plants for one or more SMRs, and has a vast range of R&D support available. Another key strength of Canadian nuclear supply chain is in nuclear engineering and the readiness of its nuclear supply chain that are ideal for new entrants into the nuclear field. The Darlington refurbishment program in Ontario demonstrated that real projects maintain the capability level of the entire industry, including R&D, engineering and project management, and the manufacturing capability of the many small and medium size companies spread across Canada. The Darlington refurbishment encouraged a new generation of Canadians to make their career in the vibrant nuclear industry. Young bright engineers and trades are using new tools and developing advanced techniques to execute their work. The potential for international collaboration will ensure continued investment in new and innovative technologies.

A new SMR industry would lead to even stronger domestic manufacturing and the development of a new generation of nuclear leaders. However, this position will not last forever. As others commit to these new SMRs, they will move forward and become the new industry leaders as their own domestic industries gain strength from these commitments. Since Canada has a domestic market for such reactors, late entry will likely result in SMRs being purchased from other countries with less than ideal Canadian participation.

Canada has the potential resources to play an important role in deploying SMRs. But Canada requires collaboration between industry and government to enable the deployment of SMRs in new energy systems that reduce costs and carbon emissions from the extraction industry, and provide reliable sources of energy to indigenous communities across the far north.

6. MACROECONOMIC BENEFITS

The deployment of small modular reactors may benefit Canada in several ways.

6.1 Domestic Market

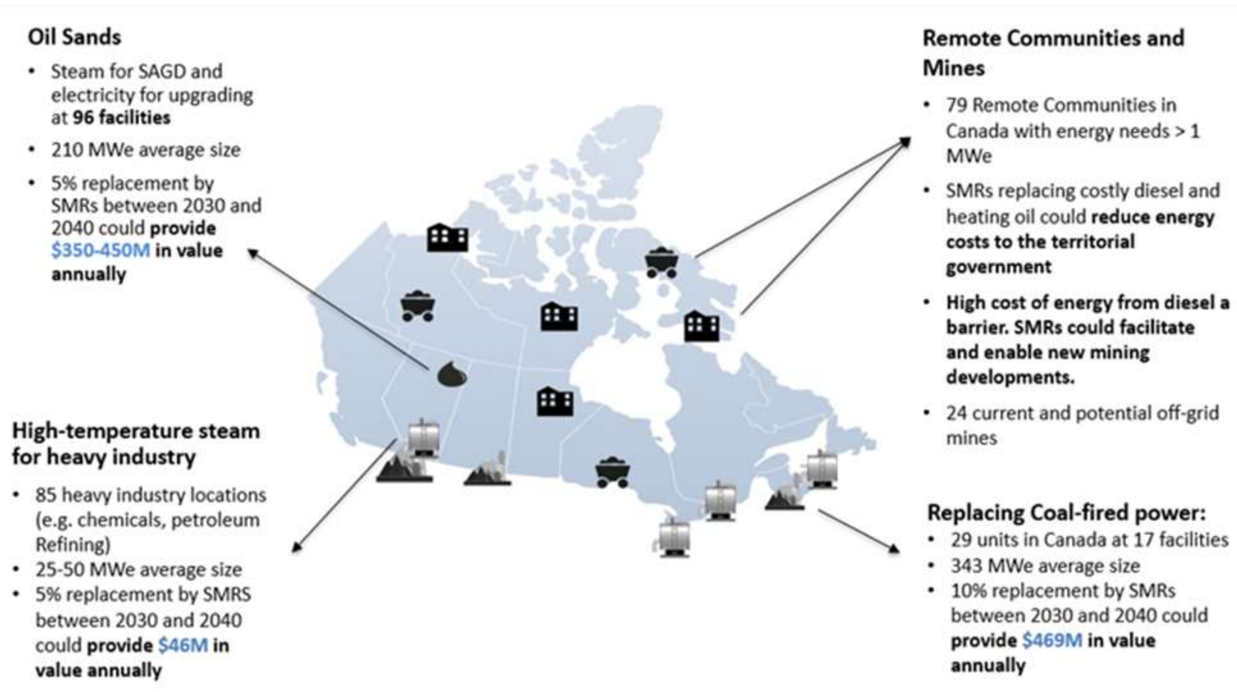
A first path is adding value to Canada's economy in terms of gross national output, tax revenues, and jobs.

In Canada, SMRs could provide non-emitting heat and power to:

- 92 oil sands facilities;
- 79 remote communities exceeding 1MW in size;
- 85 heavy industrial locations;
- 24 current and potential off-grid mines; and
- Replace 29 individual coal-fired electricity-generating units.

Sources: Wojtaszek, 2017 for oil sands, remote communities and mines

Figure 12: SMR Potential in Canada



SMRs meeting a fraction of this potential can provide significant economic benefits for Canada, including up to 6,000 direct and indirect jobs per year between 2030 and 2040, and up to $10 billion in direct impacts and $9 billion in annual indirect impacts over the same timeframe. These are conservative estimates that do not take into account potential future uses of SMRs, such as powering greenhouses, desalination, and hydrogen production, all of which could increase their overall economic potential.

In addition to these quantified financial benefits, other benefits to Canada from SMRs would include:

- reduced energy costs to the territorial government

- direct GHG reductions
- the facilitating and enabling of new mining developments that were previously uneconomic due to the high price of diesel
- furthering cutting edge research and innovation
- the enabling of an electrified or hydrogen economy (discussed further below)

The high end of the ranges above assume that about 75% of direct (initial) costs are spent in Canada, and are consistent with a domestic SMR vendor. If the SMR vendor were foreign, the value added to Canada would likely be lower (about 50% spent in Canada), making up the lower end. This percent spent in Canada would ultimately be negotiable between governments and project developer companies. An additional key assumption is that the nuclear market share is 5%-10% for all market segments. Other key assumptions for each market segment are the different reactor sizes, costs per reactor, and project life for using an SMR – assumptions which have already been included in the report.

6.2 Export Market

A second path that may benefit Canada is by exporting SMRs to foreign markets. While the potential size of this market is highly uncertain, the recent UK Nuclear Sector Deal quantified the entire potential nuclear new build market at £1.2 Trillion or $CDN 2.3 Trillion between 2018 and 2035 (HM Government, 2018). This results in an annual (undiscounted) amount of $CDN 136 Billion per year. The EFWG provided a first-order estimation of the total global export potential of SMRs of comparable magnitude, with a ***potential of $CDN 150 billion per year***. This number could be higher or lower depending on assumptions around:

- the percentage of the various markets met by SMRs (a function of relative economics, public acceptance etc.)
- the expected SMR cost
- the growth of global electricity demand
- the intensity of international efforts to mitigate climate change
- expected growth in the off-grid mining sector; and
- the extant number of remote island communities dependent on diesel that could be serviced by SMRs.

These values are indicative of an opportunity for Canada. The EFWG discerned the economic benefit of this export market to Canada by making further assumptions around:

- the percentage of the SMR market captured by Canada relative to other competitors; and
- the percentage of the Canadian supply chain that is engaged in Canadian builds abroad.

Based off these values, the potential to Canada could be approximately $1B-$3.5B per year in exports. Assumptions around these calculations are located in Appendix F.

Figure 13: SMR Global Potential

6.3 Other Potential Applications

While not quantified by the EFWG, SMRs can play an important role in a number of scenarios of a desired energy future for Canada. For example, meeting the ambitious targets of the Paris Agreement will require GHG emission reductions from virtually every sector of the global economy. A decarbonized electricity grid with low emissions intensity is a key enabler of GHG reductions via the clean electrification of end use applications that are currently using fossil fuels. Examples include the use of electricity, rather than natural gas, to heat and cool homes and buildings, or electricity, rather than gasoline, to power vehicles.

SMRs can help by both decarbonizing the existing grid, but also by helping meet the increased electricity demand expected from electrification of end use. Modelling scenarios in Canada's Mid-Century Long-Term Low-GHG Development Strategy found that, in all cases, electrification of end uses and industrial processes was necessary to meet the Paris Agreement target. In Canada, the modelling studies projected the share of electricity use to grow from 16% in 2014 to between 40% and 72% of total energy use by 2050 (Environment and Climate Change Canada, 2016). Canada will need a dramatic increase in clean sources of generation, such as SMRs, to achieve these levels of electrification. Being a firm source of capacity, and with some SMRs designed to dynamically load-follow, SMRs have a decisive advantage over intermittent sources of clean generation in meeting this increased electricity demand.

Moreover, developing a competitive nuclear industry may compliment other domestic industries in becoming more competitive, creating new opportunities. For example, the small size of SMRs do not require “ultra-heavy forged” components, whose construction are monopolized by the Japanese and Korean steel industry, and can enable Canada to develop its own domestic heavy forging industry (U.S. Department of Commerce, 2011). In addition, there is an opportunity for increasing demand for emerging manufacturing sectors, such as additive manufacturing. Currently, Canadian shipping industry companies such as Irving are investing in additive manufacturing capabilities, such as the Marine Additive Manufacturing Centre of Excellence in New Brunswick (Government of Canada, 2018). By increasing the demand for additive manufacturing, developing an SMR industry could result in spillover benefits and increased competitiveness of the Canadian additive manufacturing and shipping industry, by fostering scale economies and lower costs.

Furthermore, SMRs can play an important role in a future hydrogen economy. Hydrogen may contribute to the security of energy supplies by providing a source of non-emitting transportation fuel, if produced by zero-emission sources such as nuclear, and renewables. The adoption of hydrogen supports a strategy to use a mix of energy supply, which is consistent with the Generation Energy Council’s advice to produce cleaner oil and gas, using more renewable fuels, and an inclusive transition to cleaner energy use (Generation Energy Council, 2018). Hydrogen production from nuclear may be cost competitive against alternative energy sources, such as fossil fuel or renewable energy. Technical aspects that may lead to superior economics are increasing the outlet temperature of a reactor, and coupling a reactor with high temperature, water-splitting processes for hydrogen production that are under development and claimed to be more energy efficient and economical for GHG-free production of hydrogen. Since several SMR types are expected to operate at significantly higher temperatures, these SMRs could provide a reliable, and cost effective, source of high-temperature thermal energy for hydrogen production.

7. Conclusions/Recommendations

Recommendation: *Government to commit funding, in partnership with industry, to support activities related to research and development, development of new markets and building demonstration and first-of-a-kind projects*

Canada should signal to the international community its intention to lead the development of SMR technology. Therefore, it is important that the quantity of funding be competitive relative to other nations. The US and UK have committed approximately $250M and $350M respectively, over a multi-year period to fund the development of SMR technology domestically (2017-2018). Development of a new SMR design is estimated to be in the order of $1,000M or $500M based on a 50/50 cost-sharing with industry. Industry suggests Canada's window of opportunity is between the next 6-12 months

The committed funds will be used to fund research & development, support the development of SMR markets, fund demonstration projects and First-of-a-Kind commercial reactors. Funding will also support manufacturing for SMRs and build on new and existing supply chain capabilities

Recommendation: *To encourage the formation of a Network, whose membership is representative across energy, manufacturing, science and technology, and in partnership with the government, to identify requirements and provide expert advise for the release of funding for SMR related projects*

The formation of a network will enable collaboration between key stakeholders and industry partners, whose membership is representative across energy, manufacturing, science and technology, in partnership with the government. Through this network, joint-venture project proposals that meet the predetermined requirements, will be submitted to a government agency for review. Successful projects will be awarded funds to complete the project. It is recommended that this network operate in a similar manner as other government initiatives, and use existing agencies to appropriate and administer the funding. The funding program could mimic other funds offered such the Clean Energy Partners (NRCan) and/or Alberta Innovates funding programs.

This network could also allow for partnership between other countries, while leveraging some of Canada's key strengths (sites and flexible regulator). Inclusion into the network could help support future ventures and knowledge sharing through joint international efforts, including sharing FOAK risks.

Recommendation: *Government to commit to reduce the cost of capital for SMRs*

The cost of capital is the single greatest cost impactor for SMRs and this can be reduced through appropriate risk-sharing partnerships with the federal and provincial governments. Areas of risks include debt repayment, project schedule, first of a kind commercial deployment, upfront development costs, waste disposal and decommissioning, owner and operator models. The federal and provincial governments should, in partnership with industry, investigate ways to best risk-share or allocate costs through policy mechanisms, funding programs and other alternative means. Options for first mover projects might include loan guarantees, low-interest loans, and bi-lateral agreements (e.g. PPA) or other measures promoting stable revenues to SMR owners/operators for the power they sell.

Recommendation 3: *Federal and Provincial Governments to provide equal access to nuclear for programs and initiatives that target other forms of clean, non-emitting energy*

The government can allow for flexible and accelerated depreciation of nuclear projects alongside other clean energy and renewable projects. It is recommended that the federal and provincial governments maintain and expand their commitment to climate change targets or reduction of CO_2 through various mechanisms.

Recommendation: *Federal government to fund/co-fund key capacity building activities in areas, which have characteristics of a "public good" and provide tangible macroeconomic benefits*

Development of highly qualified people in new reactor technology (appropriate education and training). Build the nuclear energy literacy of Northern off-grid communities to understand nuclear for the possibility of incorporating it into their energy plans. Consider proposals for feasibility studies for remote deployment and indigenous engagement. Engagement with universities to provide support for research and development and career building opportunities.

Recommendation: *Ready regulators and legislators for eventual SMR deployment*

Federal Government, Waste Management Organizations, and the Regulator to continue to identify and address risks outside their control as well as barriers for SMR deployment. Recommend the above organizations work together to identify legislation that may require alternative options for SMRs.

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Appendix A: LITERATURE REVIEW SUMMARY

The working group assessed the extant literature to discern **indicative SMR costs** (e.g. unit capital and levelized costs). We reviewed studies with explicit cost estimates from a variety of sources: academic literature, research institutes, government, and consulting firms. Some of the key findings from the assessment are as follows:

- Analysts expect a first-commercial SMR to cost more than subsequent units. However, the literature also showed that capital costs per unit of installed capacity for a mature, on-grid SMRs could be less expensive than that of a Large Nuclear Power Plants (LNPP). Generally, while LNPPs derive greater benefits from economies of scale than SMRs, SMRs have the potential to overcome this cost disadvantage through their own advantages: modularity, economies of multiples, design simplification, and potentially improved construction schedules.
- Researchers expect a first commercial or demonstration SMR to cost more than prevailing generation options. This is normal based on the historic experience with energy technologies, whereby unit costs tend to decrease with increasing experience (McDonald & Schrattenholzer, 2001). Upon achieving technological maturity, SMR capital costs are in many cases lower than recent cost estimates for a large reactor.
- Key factors affecting costs, from the subset of studies which provided a methodology for deriving, costs were **unit level scaling factor**, **dynamic cost trends** (amount by which unit costs decline with construction of additional units), **design simplification,** and **co-siting benefits** from SMRs.

We noted limitations with the small sample of studies to assess costs:

I. The studies mainly focused on capital costs, while assuming similar O&M, fuel, and decommissioning costs to large reactors on a Kwh basis. Our concern with this assumption is that O&M may be even more size-dependent than capital cost (staffing, for instance, may scale down at a lower proportion than size). Similarly, the fuel costs may be quite different for SMRs due to some of them intending to use different fuels.

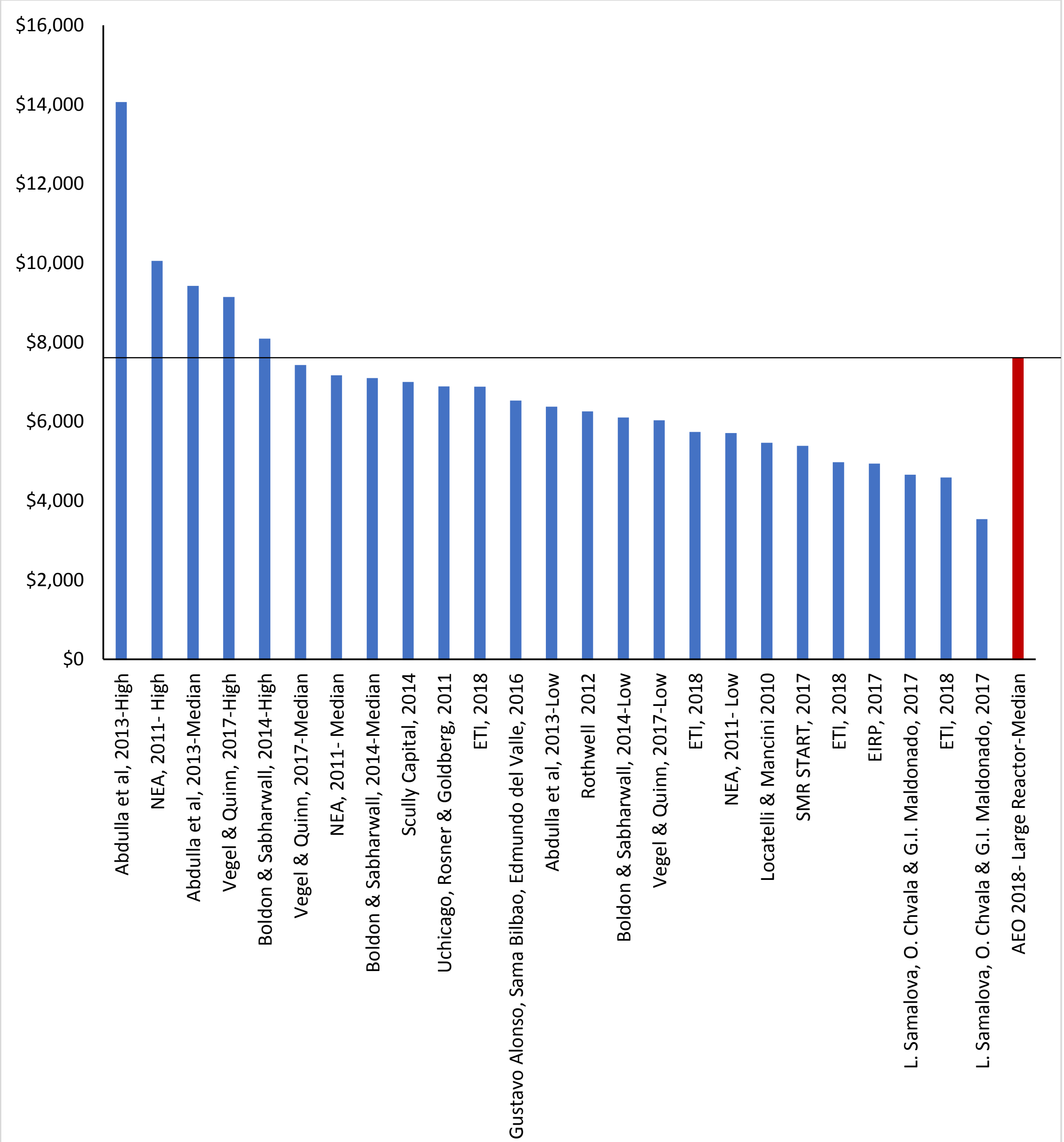
II. Many authors assess SMR costs as a scaled down variant of a large PWR via the top-down approach. In other words, they apply scale factors found in the literature for PWRs and applied them to an SMR. This calculation increased costs per KW for SMRs due to the diseconomies of scale. The EFWG questioned the validity of this approach due to SMRs using different coolants, different fuels, and dramatically different designs (even where the fuel and coolant are similar to prevailing reactors). Scaling may be a good approach for reactors with a limited size range and identical design, but not for those with vastly different sizes, designs, and equipment requirements. However, some costs categories, like regulatory costs, will still be associated with a strong scaling effect since fixed costs are independent of reactor size.

An alternative to the top-down approach is the use of bottom-up methodology, whereby costs are determined on a component-by-component basis, before being aggregated to determine total reactor capital cost. The UK Energy Innovation Reform Project (EIRP, 2017) and Samalova, Chvala, & Maldonado 2017, both used such a bottom-up approach, and estimated considerably lower SMR costs than seen with the top-down methodologies, especially for advanced reactor designs.

III. Most costing studies were for on-grid applications. Other analysis conducted by members of this working group (Moore, 2017) and a consultant study (Hatch, 2016) were the main sources looking at costing for off-grid applications, while only one study looked at the applicability of SMRs for the oil sands (Short & Schmitt, 2018).

Figure A-1 below summarizes the literature estimates for on-grid SMRS, and compares them alongside a recent large reactor estimate provided by the US Energy Information Administration.

Figure A-1: SMR Capital Costs ($2018 CDN/KW)



Appendix B: DESCRIPTION OF METHODS

The following appendix describes the methods and sources used to calculate the SMR costs.

B.1 Capital Costs

B.1.1 On-Grid

Currently, there have only been three SMR projects completed, or nearing completion, globally. The projects: one Russian, one Chinese, and one Argentinian, provided scant public data by which to assess SMR costs. Furthermore, being executed under such dramatically different institutional, policy, and financing settings, they were not deemed representative for the Canadian context.

Thus, we used two bodies of data to obtain capital cost estimates for on-grid applications: vendor data and data from sources in the literature (academic, government, and consultants). Currently ten vendors are in the process of completing the optional pre-licensing optional Vendor Design Review (VDR) offered by the Canadian Nuclear Safety Commission (CNSC) (CNSC, 2018). Where their cost data are publically available, these vendors could be a source of SMR costs in Canada. Other companies that are not undertaking the optional VDR process, but that are conceiving SMR designs, such as GE Hitachi, Toshiba, KAERI, and Rolls Royce, could also be sources of cost where their data are publically available.

Both bodies of data have potential issues pertaining to their validity.

1- *Vendors:* Vendors may lack the experience in establishing costing estimates and there is higher uncertainty with the costs for more revolutionary SMR designs. In addition, many of the vendors have not had their costing claims independently vetted. At the same time, some vendors are well-established energy/nuclear technology firms such as Westinghouse, KAERI, General Electric, and Holtec, and are pursuing variations of existing nuclear technologies where there may be a better understanding of component-level costs from which to undertake a detailed costing. NuScale, for instance, has undertaken ~10,000 person hours in conjunction with Engineering-Procurement-Construction (EPC) firm Flour to establish robust costing estimates (NuScale, 2015).

- *Academic Literature and other Third Parties:* While providing a major advantage of impartiality, cost estimates from these sources are not without their own issues. Top-down methodologies, which take the cost of a prevailing large reactor, and then apply techno-economic parameter estimates of key economic drivers to obtain the delta in cost between an SMR and a large reactor, may not adequately capture the novelty of these designs and the full potential of cost declines.

The claim made by proponents of the technology is that these are fundamentally new designs that are trying to do away with the existing paradigm, and so this top down approach will overstate potential costs. A potential solution to this would be to conduct a bottom-up analysis of likely SMR costs via detailed component–level analysis of costs. As discussed in Appendix A-1, we identified only two studies in the literature that undertook this sort of bottom-up analysis. They yielded costs that were substantially below the top-down estimates we found. The substantial differences outcome based on methodology are compounded by the wide variation in costs provided by expert analysts, indicating a high degree of uncertainty from this source of data.

For our analysis, we used a range of estimates from the literature and vendors representing the median, 10th, and 90th percentile of all claims. Actual costs could be higher or lower depending on a number of eventualities, and there were outliers on either side of the cost spectrum that the choice of percentiles deliberately sought to avoid. Figure B-1 below illustrates the range of costs from which we derived our SMR capital costs for the on-grid scenario.

Figure B-1: Range of Capital Costs Across different Sources

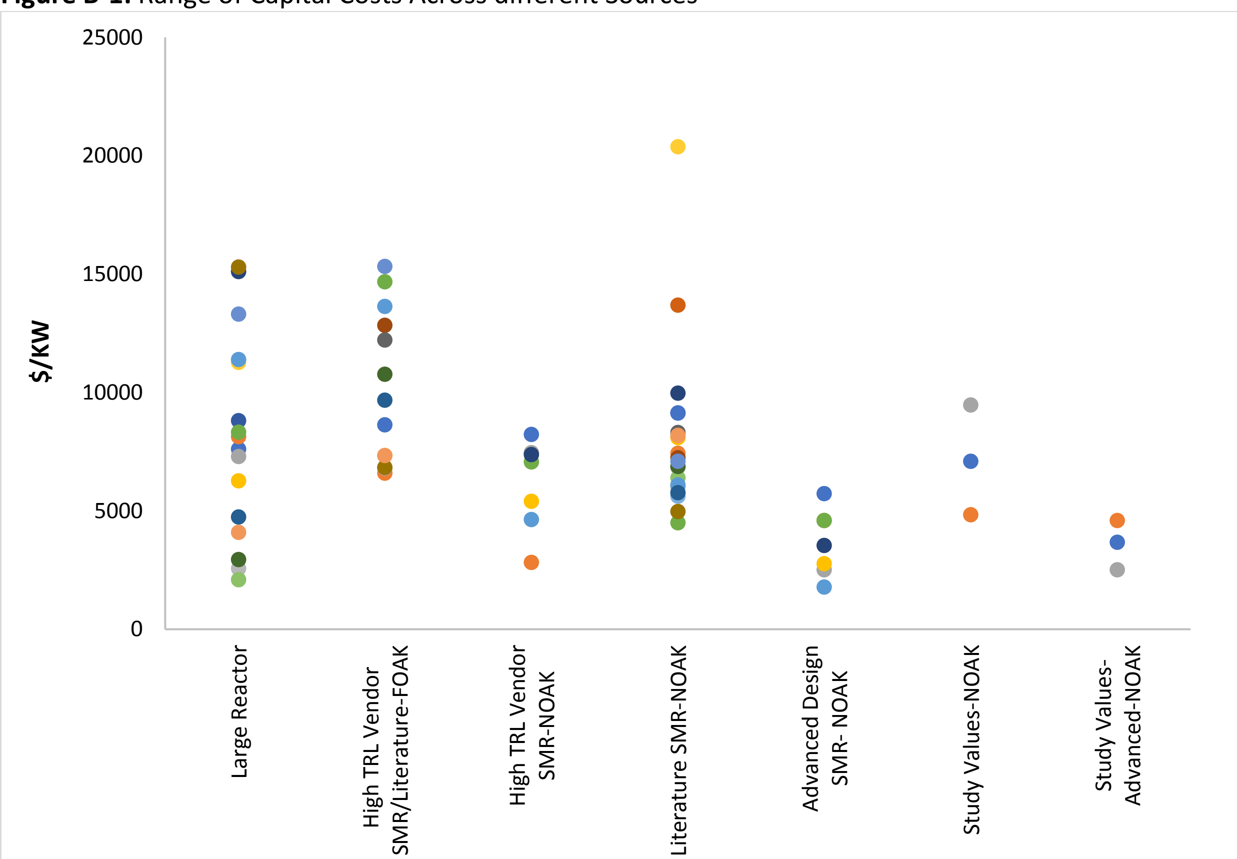


Table B-1 below provides the source for each data point in Figure B-1 Above

Table B-1: Capital Costs Various Nuclear Plants and SMRs (Constructed and Designs)

Source	$2018 CDN/KWe
Large Reactor	
AEO 2018- Median Estimate	$7,606
AEO 2018- Maximum across regions	$8,136
AEO 2018- Minimum across regions	$7299
Lazard 2017b, Overnight Low Estimate	$6,272
Lazard 2017b, Overnight High Estimate	$11,393
Lazard 2017b, All-in Low Estimate*	$8,321
Lazard 2017b, All-in High Estimate*	$15,105
Energy Technologies Institute (ETI, 2018)- Vogtle 3&4 (Highest Estimate)	$15,297
ETI, 2018- Barakah- Extrapolated average across 4 Units	$4,736
ETI, 2018- Barakah-Unit 4 Extrapolated (67% complete)	$2,944
ETI, 2018- Europe/North America Average	$13,313
ETI, 2018- Rest of the World-Average	$4,096
ETI, 2018-Low Estimate	$2,560
ETI, 2018-Hinkley Point C	$11,271
IEA, WEO- Global Average	$6,587
ETI, 2018- Lowest Value	$2,098
EIRP	$8,817
Evolutionary SMR- FOAK	
SMR Start, 2017	$8,630
NuScale-FOAK MWe Estimate	$6,593
Atkins, 2016- Vendor 1	$6,815
Atkins, 2016- Vendor 2	$7,339
Atkins, 2016- Vendor 3	$13,630
Atkins, 2016- Vendor 4	$14,679
Atkins, 2016- Vendor 5	$7339
Vegel and Quinn, 2017	$12,835
Boldon et al., 2014	$12,212
Boldon et al., 2014	$6,844
Rolls Royce, FOAK	$9,678
KAERI- 2-3 Module FOAK	$10,775
Rosner and Goldbeg, 2011 Lead	$15,333
High TRL (Evolutionary) SMR- NOAK Vendor	
NuScale- Downscaled 300 MWe Estimate	$8230
BWRX-300	$2824
KAERI- 2-3 Module	$7,455
Holtec	$5,404

Source	$2018 CDN/KWe
HTGR, vendor 1- Short & Schmitt, 2018	$4,635
HTGR, vendor 2- Short & Schmitt, 2018	$7,063
Rolls Royce	$7,374
High TRL (Evolutionary) SMR- NOAK Literature	
Vegel And Quinn, 2017	$9,140
Vegel And Quinn, 2017	$7,426
Vegel And Quinn, 2017	$6,033
Boldon et al., 2014	$8,090
Boldon et al., 2014	$6,099
Abdullah et al., 2013	$4,498
Abdullah et al., 2013	$9,980
Abdullah et al., 2013	$7,239
Abdullah et al., 2013	$8,316
ETI, 2018*	$4,971
SMR START, 2015	$5,773
ETI, 2018*	$6,889
Scully, 2014	$7,098
Scully, 2014*	$8,189
Rosner and Goldberg, 2011	$6,836
Abdullah et al., 2013	$20,381
Abdullah et al., 2013	$5,622
Idaho National Labs, 2012	$6,386
Idaho National Labs, 2012	$9,129
Idaho National Labs, 2012	$13,694
Low TRL (Revolutionary) SMR- Vendor and Literature	
ETI, 2018*	$5,735
ETI, 2018*	$4,588
Thorcon	$2,510
Moltex	$2,771
Moltex	$1,777
L. Samalova, O. Chvala & G.I. Maldonado	$4,659
L. Samalova, O. Chvala & G.I. Maldonado	$3,528

**All-In Cost.*
ETI refers to the Energy Technologies Institute Nuclear Cost Drivers Project: Summary Report

B.1.2 Off-Grid

A challenge with the off-grid remote communities and mining applications was the paucity of vendor and literature-derived specific capital cost estimates from which to benchmark capital costs. Thus, for these applications, the EFWG modelled capital costs using a top-down approach, and then benchmarked the LCOE results from these derived estimates to LCOE estimates provided by vendors.

Figure B-2 illustrates our method in a simple framework. Table B-2 summarizes some the key SMR economic drivers identified by the EFWG, and the rationale for their inclusion/exclusion to the framework for these very small reactors.

Figure B-2: Deriving Capital Costs for Very Small Off-Grid Reactors

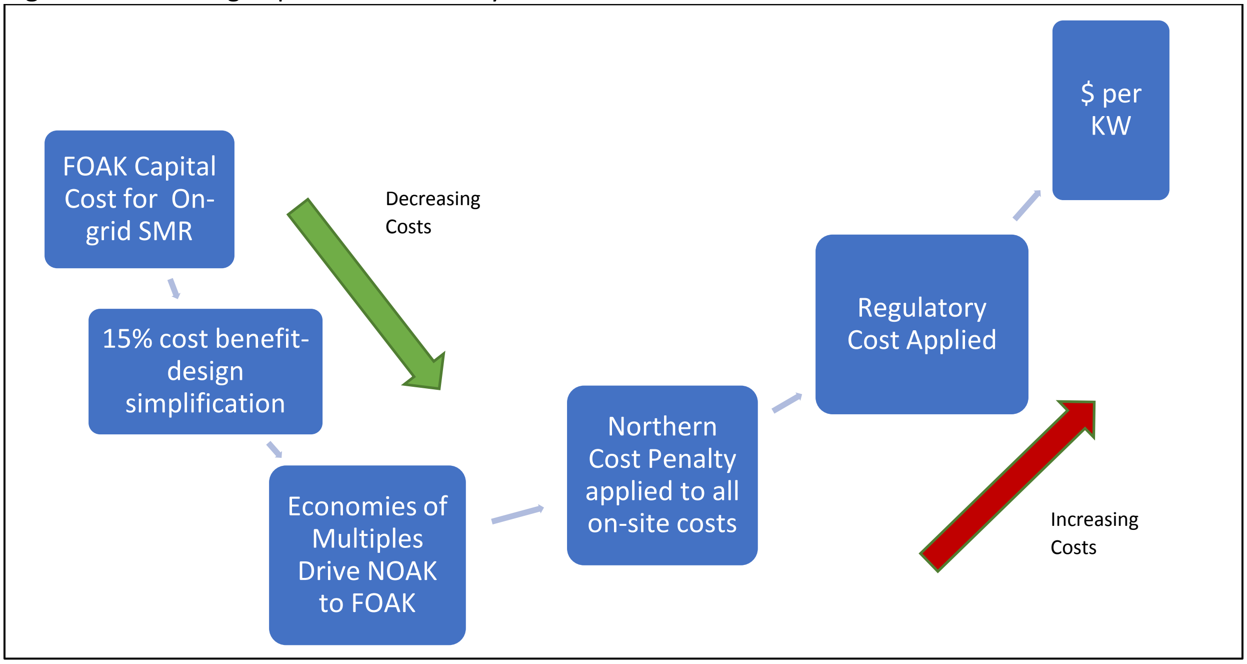


Table B-2: Economic Drivers and Rationale for Inclusion/Exclusion

Economic Driver	Status	Rationale
Economies of Scale-Technology	Excluded	The designs for these SMRs would be novel and optimized for smaller scale. Thus, it would not make sense to apply scaling factors used for scaling large reactors. We did not apply scale factors to the technology or construction cost components for SMRs.
Economies of Scale-Development Costs	Included	Development costs do not vary by scale and so are an important driver of SMR unit costs for very small capacity SMRs. We applied three costs: Optimistic ($45M), Base ($75M), and Pessimistic ($105M). Optimistic development costs were from a report presented by LeadCold reactors (Wallenius et al., 2015) and included their estimate of expected licensing costs only. The base development cost came from Hatch 2016 for a NOAK reactor and includes not only CNSC staff fees for licensing, but also environmental assessment costs, and various public engagement process costs that are essential to develop any major energy project.
Co-siting benefit	Excluded	Communities tend to be so small in terms of demand, that they will likely only see one reactor per site. Mine sites may have co-sited units, but we assumed one reactor per site for a consistent comparison with the remote community calculations.
Economies of Multiples	Included	Assumes a fleet approach of 8 Reactors- 3 cumulative doublings.

Economic Driver	Status	Rationale
Design Improvement	Included	Applies a 15% design simplification cost benefit as these would be advanced reactors optimizing new technologies and passive safety. This number is based off many top-down studies from the literature (see Vegel & Quinn, 2017; Kessides & Kuznetsov, 2012 for examples).
Off-Grid Cost Penalty	Included	Imposes a cost penalty for building in remote conditions ranging from 2X to 2.7X the initial on-site construction and installation costs (55% of all reactor construction costs).

B.2 Non-Fuel O&M costs

Non-Fuel O&M costs for energy technologies are broken down into a fixed ($/KWe) and variable ($/MWh) component. For nuclear, variable non-fuel O&M costs are low while fixed O&M costs tend to make up most of nuclear's non-fuel O&M. Most of the vendor LCOEs tend not to break down their value into the O&M components, and so our analysis required using other sources to calculate SMR O&M costs. Furthermore, we noted many of the cost estimates from the literature and third parties tended to assume the same O&M costs as prevailing large reactors, which may not be valid. Table B-3 breaks down O&M costs by components as per categories used by the International Atomic Energy Agency (IAEA, 2013). We indicate, in the second column of this table, how we expect these O&M costs to scale with differences in reactor size. We expect costs such as staffing, and annual fixed costs, such as premium payments for liability insurance, to scale down less than proportionally with size, resulting in a loss of economies of scale with these O&M cost categories for SMRs.

Table B-3: O&M Cost Components and their Cost Scaling

O&M	Independent of Size?
O&M Staff	Dependent on size up to a certain threshold, below which it is independent and a function of regulation.
Management Staff	Dependent on size up to a certain threshold, below which it is independent
Pensions and benefits	Same as above
Spare Parts/ Capital Plant Upgrades/ Utilities, supplies and purchased services/chemicals and lubricants	Assumed to scale in most cases.
Licensing renewal cost	Independent of Size
Annual Insurance Premium	Dependent on risk of damages, which scales to size with a certain degree.

For staffing, the IAEA provided estimates for how staffing levels vary by size (IAEA, 1998). They find that overall 70% of the variation in total staffing (operations, maintenance, engineering, safety, support, and site services) across reactors is due to size. For a 1000MWe plant, the total number of staff is in rough proportion to the size of the plant with 1 staff member per MWe installed capacity. The IAEA analysis shows economies of scale for plants above 1000MWe, such that fewer staff tend to be required per MW installed, but for values below 1000MWe, staffing requirements tend to scale down less than proportionally in most cases.

However, the design of SMRs are such to minimize staffing and operations requirement. For example, NuScale claims that it can staff a 600MWe NuScale facility with 365 employees, which is roughly 0.6 employees per MWe (NuScale, 2017). Thus, there was justification in using current fixed O&M costs for large reactors, and that these ay actually overstate somewhat the O&M costs for SMRs. Table B-4 below provides a number of estimates for fixed O&M costs for large reactors from the literature and by various energy analytical groups. Hewlett (1992) and Koomey & Hultman (2007) provide historic O&M data for US plants, while those from the EIA, Lazard, and EPRI provide O&M estimates for new (GENIII+) reactors.

Table B-4: Fixed O&M estimates by source

	Estimate Ranking (if Multiple Estimates)	**$2018/Kw/Yr**
Hewlett, 1992	Median from US plants	$140
	High- Highest 10% of all US plants	$288
	Low- Lowest 10% of all US plants	$100
Koomey and Hultman, 2007	Median from US plants	$140
	High- Highest 10% of all US plants	$217
	Low- Lowest 10% of all US plants	$111
EIA, 2018	NA- Only one estimate provided	$135
Lazard, 2017b	NA- Only one estimate provided	$175
EPRI, 2018	NA- Only one estimate provided	$158

As our midpoint, we used the average of the Hewlett, Koomey & Hultman, EIA, Lazard, and EPRI estimates, which provide a value of $145/KW. For our low and high scenarios, we used the Koomey and Hultman data over the Hewlett data due to the former being more recent. Variable O&M amount to $2.9/MWh as per EIA AEO 2018.

For off-grid O&M costs, the above O&M cost values would considerably understate the unit O&M costs for very small SMRs envisioned for these markets. We, thus, calculated the incremental O&M cost per KWe per year arising from the scale independent components making up O&M costs to correct fixed O&M

costs for this market. Table B-5 shows the results of this analysis and the impact on O&M for off-grid SMRs. Variable O&M costs are assumed to be scale proportionately.

We used high and low estimates for staffing and insurance premiums. The high staff estimate assumes an absolute minimum number of staff at 20, irrespective of reactor size. Staffing requirements include on-site operators, off-site corporate functional staff (engineers, maintenance, safety, admin support), and on-site security. We based these staffing estimates off Hatch (2016) which estimated a minimum security-complement of 10 FTEs, and would require approximately six operators and support staff for a 3MW site and about 10 for a 10MW site. As per Hatch (2016) we also included an additional annual security training allowance of $500k/yr to these costs. The low staff estimates assumed half the training allowance ($250k/yr) and scaled down the minimum staff requirement to 1 staff per MWe

For insurance premiums, the annual premium that the operator must pay is determined separately for each site and based on the risk and potential impact of an accident for that site. The categorization of SMRs as a Power Reactor will require they hold premiums for $1Bn of liabilities as per the Nuclear Liability and Compensation Act. There is some scale dependence with the annual premiums with existing reactors and so the EFWG expects a lower annual premium for an SMR, however, the ultimate amount of the premium is assessed on a case-by-case basis once sufficient data for an informed risk assessment can be undertaken. The EFWG used bounding estimates for the premium based on experience with different types and sizes of reactors in Canada. Given the ranges seen, lack of advance knowledge of the premium amount one must pay could pose a significant discouragement to SMR investment.

Table B-5: O&M for off-grid SMRs

	Staffing and Security Training O&M Estimate ($/KWe)	**Total O&M ($/KWe)***
Large SMR	$110	$145
20 MWe	**High:** $187.5 **Low:** $162.5	**High:** $257/KWe **Low:** $229/KWe
10 MWe	**High:** $375/KWe **Low:** $187.5	**High:** $479/KWe **Low:** $357/KWe
3MWe	**High:** $1417 $/KWe **Low:** $233/KWe	**High:** $1683/KWe **Low:** $313/KWe

*Also includes O&M for spare parts, chemicals, utilities etc. These latter cost components are assumed to be scale independent

B.3 Fuel Costs

For fuel costs, we assumed the evolutionary on-grid SMR would have identical fuel costs to a conventional light water reactor (LWR). By contrast, we assumed the off-grid and revolutionary SMRs would use higher enrichment and refueling would involve batch refueling, affecting the fuel costs. In practice, each SMR design has slightly different fuel requirements and, at a broader level, SMR fuel can be characterized by the following characteristics:

- Initial source of fissile material (uranium, plutonium and/or thorium)
- Enrichment
- Fuel type (oxide, metallic, etc.)
- Reactor power

Table B-6 below presents the unit costs for each step in the front end of the fuel cycle. All unit costs estimate are from the Advanced Fuel Cycle Cost Basis report published by Idaho National Laboratory converted to 2018 Canadian constant dollars.

Table B-6: Front End Fuel Cycle Unit Costs

Source Fissile Material			
	Uranium	$/kgU	134
	Thorium*	$/kgTh	97
	Plutonium	See reprocessing	
Uranium Enrichment			
	Uranium Enrichment	$/SWU (see figure 1)	170
Fuel Fabrication			
	CANDU	$/kgHM	300
	LWR	$/kgHM	540 – 590
	MOX	$/kgHM	770 – 1,350
	TRISO	$/kgHM	15,000[6]
Reprocessing			
	Aqueous	$/kgHM in UNF[7]	1,719

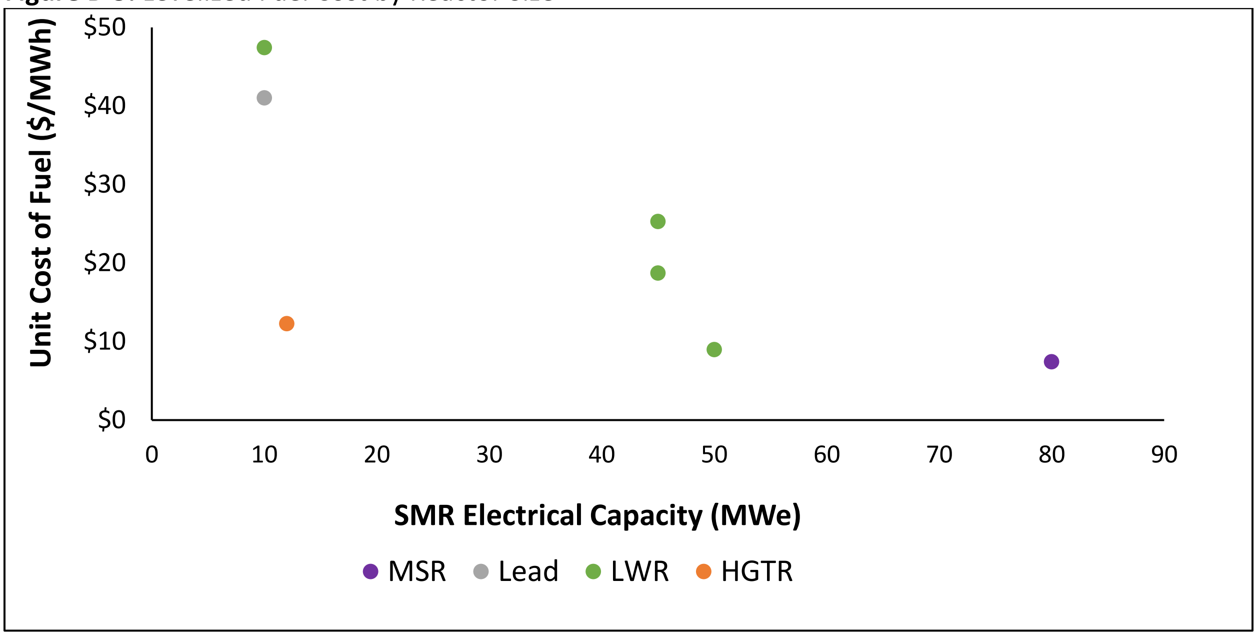
Using the unit costs in table B-6, we estimated two measures for several different SMR designs: initial core cost ($M), and unit cost ($/MWh), to determine the range in SMR fuel cycle costs. Many of the SMR designs proposed, plan to swap out the entire core each refueling. In these cases, the cost of refuelling is equivalent to the cost of the initial core. However, others have more traditional refuelling schemes where a portion of the fuel is removed and replaced with fresh fuel on a regular basis (yearly). A few SMRs, such

[6] TRISO fuel is very complex, and therefore costs significantly more to fabricate than other fuel types.
[7] The volume of UNF that must be reprocessed is dependent on the quantity of the desired isotope(s) in the UNF.

as the molten salt reactor, even propose online refueling where fresh fuel is added, and fission product gases are removed, during regular operation of the reactor.

For very small SMRs, we divided the cash flow of the total fuel cost, which includes the refueling cost and the initial core cost, by the energy produced (MWh) to estimate the unit cost of the fuel ($/MWh) for several reactor designs with different fuels (figure B-3). In general, the unit fuel costs decrease as the SMR electrical capacity increases. This is expected since fuel efficiency (neutron economy) tends to improve as the physical size of the core increases. For the 3MWe - 20MWe sized reactors that the EFWG estimated, levelized fuel costs range from $43 to $55/MWh, putting them at the higher end of this range.

Figure B-3: Levelized Fuel Cost by Reactor Size



Canada's current nuclear power plants operate using natural (non-enriched) uranium fuel. To support this, Canada has established the following facilities domestically:

- Uranium mining (primarily located in Saskatchewan)
- Uranium conversion (located in Ontario)
- CANDU fuel fabrication (located in Ontario)

None of the SMR designs currently under development use natural uranium fuel. Therefore, the adoption of a new fuel cycle will require additional supporting facilities. These facilities could be located within Canada, or internationally.

- Uranium enrichment facility: estimated capital cost $2-3 B.[8]
- Fabrication facilities:
  - LWR (<5% enriched), capital cost estimated at $135 M for facility with a capacity of 200-300 MTHM/yr.
  - MOX fuel fabrication facility capital cost- estimated at >$5 B.
  - TRISO fuel fabrication facility capital cost- estimated at ~$3 B for a facility with a capacity of 50 MTHM/yr.
- Reprocessing Facility: estimated to have a capital cost of $13-20 B.

Depending on how the used nuclear fuel and, if applicable the reprocessing waste, is stored and dispositioned, additional facilities such a high-level waster verification facility may also be required.

B.4 Carbon Costs

Our LCOE calculations for fossil fuel generation sources included various assumptions of the future carbon price. For the on-grid calculations, we examined four carbon price trajectories to discern their impact on the competitiveness of SMRs relative to CCGTs. These include:

- no carbon price scenario
- a PCF price scenario (TAX 1)
- a low-price scenario (TAX2); and
- a high-price scenario (TAX3).

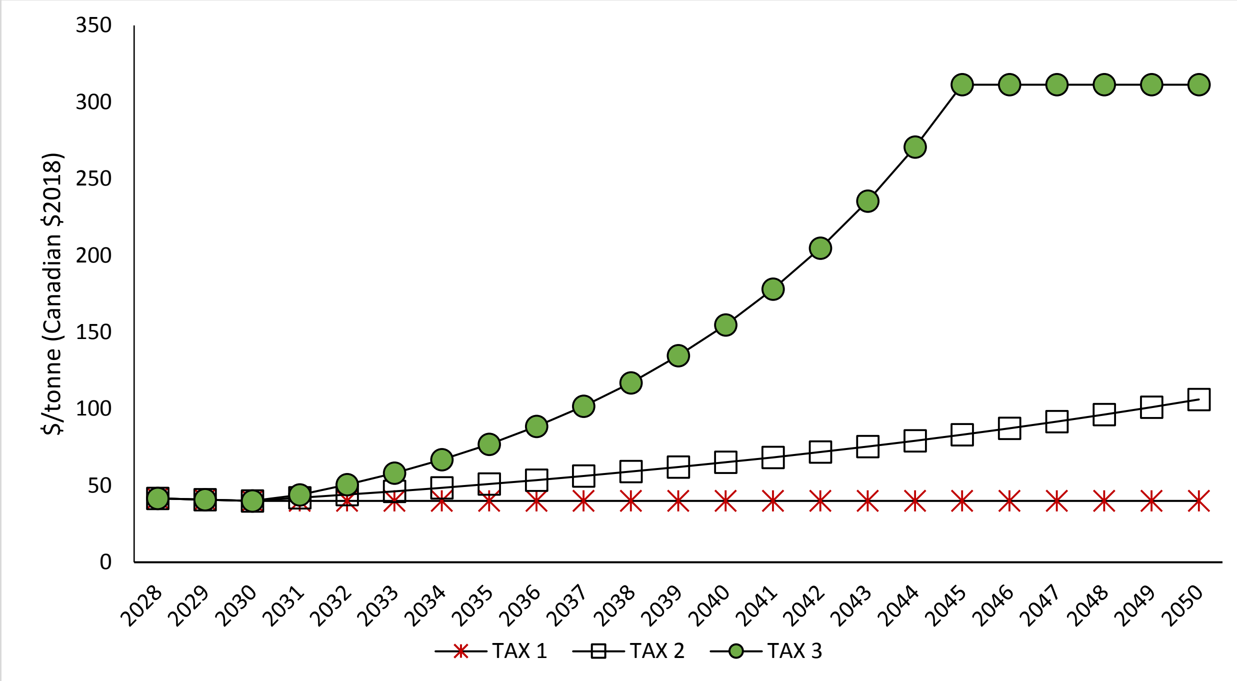
The PCF price scenario takes the Pan-Canadian Framework (PCF) Federal carbon price resting value ($50/tonne in 2023) and assumes no further increases in the price going forward. In this scenario, the carbon price will be declining in real terms. We excluded the PCF price from the graphs in the body of the report out of interest of space, although its impact was explored in the following sensitivity analysis.

The low-price scenario aligns with the PCF price scenario until 2030, after which the carbon price begins to increase in real terms at 5% per year. The high-price scenario starts at $108/tonne in 2028, which is the high end of forecasts seen for the carbon permit price under the now-defunct Ontario Cap and Trade program, and increases at 5% per year in real terms afterwards (ICF, 2017). We assume the price is capped at $300/tonne for political feasibility considerations. We excluded the high-price scenario from the off-grid analysis comparing the LCOE of SMRs vs. diesel as we assume political feasibility considerations will prevent the application of these carbon price levels to remote Northern communities, or even to remote off-grid mines.

[8] This estimate is based on current commercial enrichment facility experience which is <10% enriched uranium. Facilities capable of enriching above 10% may require additional safety and security features that could increase the capital cost of the facility.

Figure B-4 below illustrates the trajectory of the carbon price under various scenarios.

Figure B-4: Carbon Tax Trajectory



The following sensitivity analysis illustrates the LCOE of a Combined Cycle Gas turbine for different carbon prices and natural gas prices, compared to an SMR across a variety of cases. The LCOE values in the tables below represent that for a CCGT under the differing carbon and natural gas prices. Green shading means the LCOE for an SMR is less than the corresponding LCOE for a Natural Gas Combined Cycle facility. By contrast, red means the SMR costs lie above the corresponding CCGT cost for a given natural gas price and carbon price.

To make up the SMR cost cases, this analysis varied:

- The real discount rate (High-9% vs. Low- 6%)
- High TRL vs. Low TRL designs
- SMR capital cost estimates (High-TRL: Median $CDN 7098/KW, High $CDN 9476/KW, and Low $CDN 4836/KW; Low TRL: Median $CDN 3245/KW SMR Capital Cost)

i) High TRL SMRs

Case 1: High TRL SMR, Low Discount Rate, Median Capital Cost
SMR LCOE: $87/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106.0
AEO2018-High	$82.2	$95.4	$102.5	$129.7

Case 2: High TRL SMR, Low Discount Rate, Low Capital Cost
SMR LCOE: $66/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106.0
AEO2018-High	$82.2	$95.4	$102.5	$129.7

Case 3: High TRL SMR, Low Discount Rate, High Capital Cost
SMR LCOE: $116/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106.0
AEO2018-High	$82.2	$95.4	$102.5	$129.7

Case 4: High TRL SMR, High Discount Rate, Median Capital Cost
SMR LCOE: $110/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106
AEO2018-High	$82.2	$95.4	$102.5	$129.7

Case 5: High TRL SMR, High Discount Rate, Low Capital Cost
SMR LCOE: $81/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106.0
AEO2018-High	$82.2	$95.4	$102.5	$129.7

Case 6: High TRL SMR, High Discount Rate, High Capital Cost
SMR LCOE: $147/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106.0
AEO2018-High	$82.2	$95.4	$102.5	$129.7

ii) Low TRL SMRs

Case 7: Low TRL SMR, High Discount Rate, Median Capital Cost
SMR LCOE: $82/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106.0
AEO2018-High	$82.2	$95.4	$102.5	$129.7

Case 8: High TRL SMR, Low Discount Rate, Median Capital Cost
SMR LCOE: $70/MWh

Natural Gas Price	Carbon Price: None	TAX 1	TAX 2	TAX 3
AEO2018-Low	$47.9	$61.1	$68.2	$95.4
AEO2018-Reference	$58.6	$71.8	$78.9	$106.0
AEO2018-High	$82.2	$95.4	$102.5	$129.7

Appendix C: ASSUMPTIONS SUMMARY ON-GRID LCOE COST ESTIMATE

The EFWG calculated a range of LCOE costs for each technology from three scenarios: low, median, and high. The parameters that we varied to construct the three scenarios are provide in table C-1 below, while table C-2 provides the inputs and outputs. Table C-3 provides further sources and references.

Table C-1: Scenarios by Technology

Technology	Low Cost	Median	High	Source
SMR (High and Low TRL)	10th percentile Capital cost and Fixed O&M cost Value	Median Capital cost and Fixed O&M cost Value	90th percentile Capital cost and Fixed O&M cost Value	Range of literature and vendor SMR estimates for both capital and O&M cost (See Appendix B)
Natural Gas Combined Cycle	AEO 2018 Abundant Gas case natural gas price forecasts (plant gate prices)	AEO 2018 reference case natural gas price forecasts (plant gate prices)	AEO 2018 Low Gas case natural gas price forecasts (plant gate prices)	Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2018
Natural Gas Combined Cycle with CCS	AEO 2018 Abundant Gas case natural gas price forecasts (plant gate prices) AEO 2018- Lowest Capital Cost	AEO 2018 reference case natural gas price forecasts (plant gate prices) AEO 2018- Median Capital Cost	AEO 2018 Low Gas case natural gas price forecasts (plant gate prices) AEO 2018- Highest Capital Cost	Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2018
Large Hydro	Modelled off Rommaine River- lowest capital cost seen amongst recent large hydro projects in Canada. 73% capacity factor modelled of Keeyask- highest capacity factor seen from recent projects in Canada	Median capital cost and capacity factor from sample of recent Canadian large hydro projects	Highest capital cost and from sample of recent Canadian large hydro projects	Median (CANADIAN ENERGY RESEARCH INSTITUTE, 2018); Other projects included Keeyask, Rommaine River, Conwapa, and Site C (Sources: Manitoba Hydro, 2013; Boston Consulting Group, 2016; Keeyask, 2012; BC Hydro,

Technology	Low Cost	Median	High	Source
				2014; BC Hydro, 2013)
Large Hydro-Non-Hydro Jurisdiction	Lowest Estimate from Range Provided	Median Estimate from Range Provided	Highest Estimate from Range Provided	Range of LCOEs calculated by SaskPower for Hydro in Saskatchewan (SaskPower, 2017)
Wind	45% Capacity Factor	33% Capacity Factor	27% Capacity Factor; Higher wind project capital cost based off of EIA data - $2121/KW	Median- NRCan Consultation with experts on average for Canada 45% EIA AEO 2018 27% Based-off Lowest wind capacity factors in US (Wiser & Bollinger, 2016)
BC Run of River	Lowest site screened	Median of all sites screened	90th percentile of site screened	BC Hydro's 2013 Integrated Resource Plan; 55 best sites in BC

Table C-2: On-Grid Inputs and Outputs Table

	SMR-Evolutionary	**SMR-Revolutionary**	**Natural Gas Combined Cycle**	**NGCC-CCS**	**Wind**	**BC Run of River**	**Large Hydro (New)**	**Large Hydro (Non Hydro)**
In-Service Date	2030	2030	2030	2030	2030	2030	2030	2030
Capital cost ($/KW)-Median	$7,098	$3245	$1,549	$2,862	$1891	-	$5,422	-
Capital cost ($/KW)-Low Cost	$4837	$2510	$1,549	$2,477	$1891	-	$5,032	-
Capital cost ($/KW)-High Cost	$9476	$4588	$1,549	$3,982	$2121	-	$6,288	-
Fixed O&M ($/KW/Yr)-Median	$145	$145	$14.22	$42	$61	-	$54	-
Fixed O&M ($/KW/Yr)- Low Cost	$110	$110	$14.22	$42	$61	-	$54	-
Fixed O&M ($/KW/Yr)- High Cost	$220	$220	$14.22	$42	$61	-	$54	-
Variable O&M ($/MWh)	0.00	$2.22	$2.22	$9.04	$0.00	-	0	-

	SMR-Evolutionary	SMR-Revolutionary	Natural Gas Combined Cycle	NGCC-CCS	Wind	BC Run of River	Large Hydro (New)	Large Hydro (Non Hydro)
Fuel (average $/MMBTU over life)-Median	$0.84	$0.84	$6.44 average price (30% increase 2030 to 2059)	$6.44 average price (30% increase 2030 to 2059)	0	-	0	-
Fuel (average $/MMBTU over life)-Low Cost	$0.84	$0.84	$4.41 average price (flat price)	$4.41 average price (flat price)	0	-	0	-
Fuel (average $/MMBTU over life)-High Cost	$0.84	$0.84	$10.86 average price (50% increase 2030-2059)	$10.86 average price (50% increase 2030-2059)	0	-	0	-
Heat Rate (BTU/kwh)	10,450	6,200	6,200	7,493	NA	-	NA	-
Total decomissioning cost ($/KW)	$1,761	0	0	0	0	-	0	-
Nominal Discount rate	9%/6%	9%/6%	9%/6%	9%/6%	9%/6%	9%/6%	9%/6%	-
Capacity Factor-Median	90%	90%	90%	90%	33%	-	62%	-
Capacity Factor-Low Cost	90%	90%	90%	90%	45%	-	73%	-
Capacity Factor-High Cost	90%	90%	90%	90%	27%	-	62%	-
Economic Life	40	20	20	20	20	-	70	-
LCOE- CAPITAL-Median	9%- $69.9 6%- $46.3	9%- $33.2 6%- $21.9	9%- $20.1 6%- $15.2	9%-$37 6%-$28	9%-$67 6%-$51	-	9%- $95 6%- $51	-
LCOE- CAPITAL-Low Cost	9%- $46.9 6%- $31.1	9%- $25.7 6%- $16.9	9%- $20.1 6%- $15.2	9%-$32 6%-$24	9%-$49 6%-$37	-	9%- $80 6%- $43	-
LCOE- CAPITAL-High Cost	9%- $94.2 6%-$62.4	9%- $46.9 6%-$31	9%- $20.1 6%- $15.2	9%-$51 6%-$39	9%-$82 6%-$62	-	9%- $110 6%- $60	-
LCOE- FIXED O&M- Median	9%-$23.5 6%-$25.1	9%-$23.5 6%-$25.1	9%-$2.1 6%-$2.1	9%-$6.3 6%-$6.4	9%-$24 6%-$24	-	9%-$13.55 6%-$15.71	-
LCOE- FIXED O&M- Low Cost	9%-$17.8 6%-$19	9%-$17.8 6%-$19	9%-$2.1 6%-$2.1	9%-$6.3 6%-$6.4	9%- $18 6%-$18	-	9%-$11.51 6%-$13.55	-
LCOE- FIXED O&M- High Cost	9%-$35.7 6%-$38	9%-$35.7 6%-$38	9%-$2.1 6%-$2.1	9%-$6.3 6%-$6.4	9%- $30 6%-$30	-	9%-$13.55 6%-$15.71	-

	SMR-Evolutionary	SMR-Revolutionary	Natural Gas Combined Cycle	NGCC-CCS	Wind	BC Run of River	Large Hydro (New)	Large Hydro (Non Hydro)
LCOE-Variable O&M and Fuel-Median	9%- $8.9 6%-$9.1	9%- $8.9 6%-$9.1	9%-$40.8 6%-$40.6	9%-$56 6%-$56	$0.00	-	$0.00	-
LCOE-Variable O&M and Fuel-Low Cost	9%- $8.9 6%-$9.1	9%- $8.9 6%-$9.1	9%-$30.4 6%-$29.9	9%-$44 6%-$44	$0.00	-	$0.00	-
LCOE-Variable O&M and Fuel-High Cost	9%- $8.9 6%-$9.1	9%- $8.9 6%-$9.1	9%-$64 6%-$64	9%-$84 6%-$85	$0.00	-	$0.00	-
LCOE-Decommissioning	9%- $2.39 6%- $2.78	9%- $2.39 6%- $2.78	$0.00	$0.00	$0.00	-	$0.00	-
LCOE Carbon Charge- Low	$0.00	$0.00	9%-$20.3 6%-$20.4	NA	$0.00	-	$0.00	-
LCOE Carbon Charge- High	$0.00	$0.00	9%-$58.1 6%-$60.7	9%-$7 6%-$7	$0.00		$0.00	
LCOE- Total-9%-Median Cost	**$110**	**$82**	**$63**	**$106**	**$91**	**$167**	**$108**	**$162**
LCOE- Total-9%-Low Cost	**$81**	**$63**	**$53**	**$89**	**$62**	**$118**	**$91**	**$133**
LCOE- Total-9%-High Cost	**$147**	**$102**	**$86**	**$148**	**$112**	**$211**	**$123**	**$191**
LCOE- Total-6%-Median Cost	**$87**	**$70**	**$58**	**$98**	**$76**	**-**	**$67**	**-**
LCOE- Total-6%-Low Cost	**$66**	**$54**	**$47**	**$82**	**$52**	**-**	**$56**	**-**
LCOE- Total-6%-High Cost	**$116**	**$87**	**$82**	**$138**	**$93**	**-**	**$75**	**-**

*****Excludes all incremental costs for required transmission capacity

Table C-3: Other inputs and Source

Technology	Source
SMR Decommissioning Cost	Decommissioning cost assumed to be $1.75M (CDN2018) per MWe- about 25% of the initial capital cost of the reactor (NEA, 2016). This cost is amortized over 100 years (includes a 10 year “cool-of period”)
SMR Development Cost	Applied $75M of development costs (Hatch, 2016 – NOAK cost).
SMR Fuel	Uranium price forecasts from EIA- AEO 2018
Large Hydro	Fixed O&M including water rentals of $54/KW/Year (CANADIAN ENERGY RESEARCH INSTITUTE, 2018; BC Hydro 2013).
Large Hydro	Capacity factor of 62%; average of Keeyask (73%); Conowapa (58%); Rommaine River (59%); Site C (57%)
Capital Expenditure Schedule- SMR, Natural Gas Combined Cycle, Natural Gas Combined Cycle with CCS, Wind	2%, 15%, 75%, 8%
Hydro Capital Expenditure Schedule	20%,15%,15%,10%,10%,10%,10%,10% as per CANADIAN ENERGY RESEARCH INSTITUTE, 2018

Technology	Source
NGCC, Natural Gas CCS	Unless otherwise stated, economic data for pertinent economic parameters modelled off the US Energy Information Agency's (EIA's), Annual Energy Outlook (AEO) 2018
Wind Capital Cost	Low/Medium-Capital Cost average (AEO 2018) minus 10% reflecting cost improvements in onshore wind by 2030. High- Capital Cost average (AEO 2018)- No future cost improvement
Economic Life	Lazard 2017b, AEO 2018 Hydro modelled off BC Hydro estimates for Site C (70 years economic life)
Common	
O&M Cost Escalator	Escalator of 2% in real terms applied per year to reflect higher O&M with older plants (Lazard, 2017b).
Exchange Rate	20 year cycle average- 1.255CDN per US
Interest During Construction (IDC)	Excluded. All technologies save large hydro have same construction time and financing. The exclusion of IDC may understate large hydro's LCOE.

Appendix D: ASSUMPTIONS SUMMARY OFF-GRID LCOE COST ESTIMATE

The EFWG calculated a range of LCOE costs for each technology from three scenarios: low, median, and high. The parameters that we varied to construct the three scenarios are provide in table D-1 below while table D-2 provides the inputs and outputs. Table D-3 provides further sources and references.

Table D-1: Scenarios by Technology

Technology	Low Cost	Median	High	Source
SMR-Community	Low Development Cost ($45M) Low Northern On-site Multiplier- 2X of all on-site costs	Median Development Cost ($75M) Median Northern On-site Multiplier- 2.4X of all on-site costs	High Development Cost ($105M) High Northern On-site Multiplier- 2.75X of all on-site costs	Development Cost- Hatch, 2016; Wallenius et al., 2015 (low) **Multiplier:** Median and high from Atlus Group, (2018)- Iqaluit and remote community cost index respectively
Diesel-Community (Barge)	AEO 2018 Abundant Oil case distillate price forecasts (plant gate)	AEO 2018 Reference Oil case distillate price forecasts (plant gate)	AEO 2018 Low Oil case distillate price forecasts (plant gate)	Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2018
Diesel (plane)	$60/Mwh	$66/Mwh	$72/MWh	Confidential Source
Small Hydro	Range of capital and O&M costs taken from sources in the literature			5-10MWe- Knight Piesod Consulting- Evaluation of Small Hydro Options for Iqaluit 3MWe and below- Government of the North West Territories, 2015.
Diesel-Mine	AEO 2018 Abundant Oil case distillate price forecasts (plant gate)	AEO 2018 Reference Oil case distillate price forecasts (plant gate)	AEO 2018 Low Oil case distillate price forecasts (plant gate)	Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2018

Table D-2: Off-Grid Inputs and Outputs Table

	SMR-10MWe	SMR-3MWe	SMR-20MWe (Mine)	Diesel- Barge (low carbon price)	Diesel: Plane	Diesel: Mine (Barge)	Small Hydro-3 MWe	Small Hydro-10 MWe
In-Service Date	2030	2030	2030	2030	2030	2030	2030	2030
Capital cost ($/KW)-Median	$17,315	$34,815	$13,565	$1017	-	$1017	$40,000	$19,000
Capital cost ($/KW)-Low Cost	$12,789	$23,289	$10,539	$1017	-	$1017	$30,000	$11,030
Capital cost ($/KW)-High Cost	$23,419	$52,586	$17,169	$1017	-	$1017	$70,000	$31,316
Fixed O&M ($/KW/Yr)- Median	$357	$998	$243	$980	-	$12.6	$1220	$1220
Fixed O&M ($/KW/Yr)- Low Cost	$235	$313	$229	$980	-	$12.6	$802	$802
Fixed O&M ($/KW/Yr)- High Cost	$454	$1684	$257	$980	-	$12.6	$1488	$1488
Variable O&M ($/MWh)	$3	$3	$3	$2.5	-	$2.5	$0.00	$0.00
Fuel -Median	$32M fuel bundle. Replaced after 10 years	$9.72M fuel bundle. Replaced after 10 years	$64M fuel bundle. Replaced after 10 years	Average $30.34 /MMBTU (0.67% growth per year)	-	Average $30.34 /MMBTU (0.67% growth per year)	$0.00	$0.00
Fuel (average $/MMBTU over life)-Low Cost	$32M fuel bundle. Replaced after 10 years	$9.72M fuel bundle. Replaced after 10 years	$64M fuel bundle. Replaced after 10 years	Average $26.7/MMBTU (0.26% growth per year)	-	Average $26.7/MMBTU (0.26% growth per year)	$0.00	$0.00
Fuel (average $/MMBTU over life)-High Cost	$32M fuel bundle. Replaced after 10 years	$9.72M fuel bundle. Replaced after 10 years	$64M fuel bundle. Replaced after 10 years	Average $33.4/MMBTU (1% growth per year)	-	Average $33.4/MMBTU (1% growth per year)	$0.00	$0.00
Heat Rate (BTU/kwh)	10,450	10,450	10,450	9,750	-	9,750	NA	NA
Total decommissioning cost ($/KW)	10,450	10,450	10,450	NA	-	NA	NA	NA
Nominal Discount rate	9%/6%	9%/6%	9%/6%	9%/6%	9%/6%	9%/6%	9%/6%	9%/6%
Capacity Factor- Median	90%	90%	90%	90%	90%	90%	80%	80%
Capacity Factor- Low Cost	90%	90%	90%	90%	90%	90%	80%	80%
Capacity Factor- High Cost	90%	90%	90%	90%	90%	90%	80%	80%
Economic Life	30	30	20	30	30	20	50	50

	SMR-10MWe	SMR-3MWe	SMR-20MWe (Mine)	Diesel- Barge (low carbon price)	Diesel: Plane	Diesel: Mine (Barge)	Small Hydro-3 MWe	Small Hydro-10 MWe
LCOE- CAPITAL- Median	9%- $108 6%- $75	9%- $108 6%- $75	9%- $126 6%- $95.5	9%-$11 6%-$7.8	-	9%-$13 6%-$9.9	9%- $493 6%-	9%- $187 6%- $
LCOE- CAPITAL- Low Cost	9%- $91 6%- $63	9%- $91 6%- $63	9%- $106 6%- $81	9%-$11 6%-$7.8	-	9%-$13 6%-$9.9	9%- $370 6%-	9%- $136 6%-
LCOE- CAPITAL- High Cost	9%- $120 6%- $83.5	9%- $120 6%-$83.5	9%- $140 6%- $106	9%-$11 6%-$7.8	-	9%-$13 6%-$9.9	9%- $862 6%-	9%- $386 6%-
LCOE- DEVELOPMENT- Median	9%- $94 6%- $62	9%- $313 6%- $206	9%- $55 6%- $39	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost
LCOE- DEVELOPMENT- Low Cost	9%- $56 6%- $37	9%- $188 6%- $124	9%- $92 6%- $24	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost
LCOE- DEVELOPMENT- High Cost	9%- $157 6%-$103	9%- $522 6%-$344	9%- $33 6%-$66	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost	Included in Capital Cost
LCOE- FIXED O&M- Median	9%-$56 6%-$58	9%- $155 6%- $161	9%-$36 6%-$36	9%-$173 6%-$180	-	9%-$1.9 6%-$1.9	9%- $229 6%- $251	9%- $229 6%- $251
LCOE- FIXED O&M- Low Cost	9%-$37 6%-$38	9%- $49 6%- $51	9%-$38 6%-$39	9%-$173 6%-$180	-	9%-$1.9 6%-$1.9	9%- $151 6%- $165	9%- $151 6%- $165
LCOE- FIXED O&M- High Cost	9%-$71 6%-$74	9%- $262 6%-$273	9%-$34 6%-$34	9%-$173 6%-$180	-	9%-$1.9 6%-$1.9	9%- $280 6%- $307	9%- $280 6%- $307
LCOE-Variable O&M and Fuel- Median	9%- $57 6%-$51	9%- $57 6%-$51	9%-$45 6%- $38.5	9%-$290 6%-$294	-	9%-$287 6%-$289	$0.00	$0.00
LCOE-Variable O&M and Fuel- Low Cost	9%- $57 6%-$51	9%- $57 6%-$51	9%-$45 6%- $38.5	9%-$260 6%-$261	-	9%-$259 6%-$260	$0.00	$0.00
LCOE-Variable O&M and Fuel- High Cost	9%- $57 6%-$51	9%- $57 6%-$51	9%-$45 6%- $38.5	9%-$316 6%-$321	-	9%-$310 6%-$312	$0.00	$0.00
LCOE- Decommissioning	9%- $3.36	9%- $11 6%- $13	9%- $2 6%- $3	$0.00	-	$0.00	$0.00	$0.00

	SMR- 10MWe	SMR- 3MWe	SMR- 20MWe (Mine)	Diesel- Barge (low carbon price)	Diesel: Plane	Diesel: Mine (Barge)	Small Hydro-3 MWe	Small Hydro- 10 MWe
	6%- $4.05							
LCOE Carbon Charge- Low	$0.00	$0.00	$0.00	$46	-	$39	$0.00	$0.00
LCOE Carbon Charge- High	$0.00	$0.00	$0.00	NA	-	NA	$0.00	$0.00
LCOE- Total-9%- Median Cost	**$315**	**$641**	**$264**	**$500**	**$650**	**$302**	**$722**	**$416**
LCOE- Total-9%- Low Cost	**$241**	**$348**	**$220**	**$469**	**$620**	**$274**	**$454**	**$285**
LCOE- Total-9%- High Cost	**$405**	**$941**	**$317**	**$525**	**$720**	**$325**	**$1,142**	**$666**
LCOE- Total-6%- Median Cost	**$246**	**$502**	**$211**	**$506**	**$650**	**$300**	**$545**	**$363**
LCOE- Total-6%- Low Cost	**$190**	**$264**	**$179**	**$474**	**$620**	**$271**	**$357**	**$242**
LCOE- Total-6%- High Cost	**$311**	**$759**	**$250**	**$533**	**$720**	**$324**	**$821**	**$537**

***Excludes all incremental costs for required transmission capacity**

Table D-3: Other inputs and Source

Category	Source
SMR Decommissioning Cost	Decommissioning cost assumed to be $1.75M (CDN2018) per MWe- about 25% of the initial capital cost of the reactor (Nuclear Energy Agency/OECD, 2016). This cost is amortized over 100 years (includes a 10 year “cool-of period”).
SMR Capital Cost for Technology	Started with the FOAK cost for a large SMR, we then reduced cost by 15% to reflect design simplification. Costs decline further at learning rates of 7% to 15% for pre-fabricated cost components and 2% to 8% for on site components (construction learning). Assumes 8 cumulative doublings. We also modelled a one-off decline due to labour savings amounting to a 50% reduction on the labour portion of the prefabricated components. We assume labour represents 40% of the prefabricated portion costs.
SMR Fuel Cost	Fuel is 19.9% high enriched U with an initial a core cost of $32.34M and a core replacement every 10 years.
Diesel- Community O&M	Fixed O&M was taken from Qulliq annual reports as per Table 2 in Moore (2017). We removed all O&M applicable to overhead and fuel, and applied the rest as project-specific fixed O&M (half of the cost for the following categories: salaries, supplies, travel, amortisation and disposal of assets- pro-rated on a MW basis)
Capital Expenditure Schedule- Diesel, SMR	2%, 15%, 75%, 8% (same as on-grid)
Hydro Capital Expenditure Schedule	6 year construction schedule in equal shares per year
Common	

Category	Source
O&M Cost Escalator	Escalator of 2% in real terms applied per year to reflect higher O&M with older plants (Lazard, 2017b).
Exchange Rate	20 year cycle average- 1.255CDN per US
Carbon Price	Low carbon tax scenarios applied for all fossil fuel technologies

Appendix E: SUMMARY OF ASSUMPTIONS & ECONOMIC POLICY FOR DIFFERENT FOAK MARKETS

In all tables below, annual fixed opex refers to all O&M costs

Assumptions: On-Grid (Base case, 300 MW)

On-Grid (Bridge diagram)	**FOAK (on-grid) 300 MW**	**FOAK (on-grid) Dev time**	**FOAK (on-grid) LG + Reg. Return**	**SMR (on-grid) 300 MW**
Case	**1**	**2**	**3**	**4**
LCOE	$ 162.67	$ 159.42	$ 108.95	$ 87.31
LCOE Break Down				
Construction Costs (excl. IDC)	73.1%	74.0%	63.4%	54.4%
Development & Pre-Construction Costs	3.2%	1.8%	1.5%	1.9%
Variable Costs	8.6%	8.7%	12.8%	16.0%
Fixed Costs (includes capex)	11.3%	11.5%	16.9%	21.0%
Decommissioning Costs	3.9%	3.9%	5.4%	6.7%
Construction & Dev. Assumptions				
Capital Costs (excl. IDC, $M)	3,036	3,036	3,036	2,129
Development & Pre-Construction Costs ($M)	126	72	72	72
IDC (2018, $M)	-	-	144	77
Development time (months)	84	72	72	72
Construction time (months)	48	48	48	36
Project Schedule (Dev to COD, months)	108	72	72	60
Capital Cost Assumptions				
Capital Cost, $000's/kW	10,120	10,120	10,120	7,098
Fixed O&M (includes Capex), $000's/kW-yr	145	145	145	145
Annaul Fixed Opex., $000's/year	43,500	43,500	43,500	43,500
Financing Assumptions				
Corporate Tax Rate	-	-	-	-
Equity Ratio	100.00%	100.00%	45.00%	45.00%
Return on Equity	10.00%	10.00%	8.78%	8.78%
Debt Ratio	-	-	55.00%	55.00%
All-in Debt Rate	10.00%	10.00%	4.00%	4.00%
WACC (nominal)	10.00%	10.00%	6.15%	6.15%
WACC (real)	7.84%	7.84%	4.07%	4.07%

Assumptions: Off-Grid Heavy Industry (125 MW)

Heavy Industry (Bridge diagram)	**FOAK (off-grid) 125 MWe**	**FOAK (off-grid) Dev. Time**	**FOAK (off-grid) LG + Reg. Return**	**FOAK (off-grid) Fleet Ops.**	**SMR (off-grid) 125 MWe**
Case	**5**	**6**	**7**	**8**	**9**
LCOE	$ 178.01	$ 171.63	$ 118.17	$ 111.84	$ 90.08
LCOE Break Down					
Construction Costs (excl. IDC)	67.3%	69.6%	58.7%	62.0%	52.9%
Development & Pre-Construction Costs	7.4%	4.2%	3.5%	3.7%	4.7%
Variable Costs	7.8%	8.1%	11.9%	12.5%	15.5%
Fixed Costs (includes capex)	13.9%	14.4%	20.9%	16.4%	20.4%
Decommissioning Costs	3.5%	3.7%	5.0%	5.2%	6.5%
Construction & Dev. Assumptions					
Capital Costs (excl. IDC, $M)	1,265	1,265	1,265	1,265	887
Development & Pre-Construction Costs ($M)	126	72	72	72	72
IDC (2018, $M)	-	-	67	67	38
Development time (months)	84	72	72	72	72
Construction time (months)	48	48	48	48	36
Project Schedule (Dev to COD, months)	108	72	72	72	60
Capital Cost Assumptions					
Capital Cost, $000's/kW	10,120	10,120	10,120	10,120	7,098
Fixed O&M (includes Capex), $000's/kW-yr	195	195	195	145	145
Annaul Fixed Opex., $000's/year	24,375	24,375	24,375	18,125	18,125
Financing Assumptions					
Corporate Tax Rate	-	-	-	-	-
Equity Ratio	100.00%	100.00%	45.00%	45.00%	45.00%
Return on Equity	10.00%	10.00%	8.78%	8.78%	8.78%
Debt Ratio	-	-	55.00%	55.00%	55.00%
All-in Debt Rate	10.00%	10.00%	4.00%	4.00%	4.00%
WACC (nominal)	10.00%	10.00%	6.15%	6.15%	6.15%
WACC (real)	7.84%	7.84%	4.07%	4.07%	4.07%

Assumptions: Off-Grid Remote Mining (20 MW)

Off-Grid Remote Mining (Bridge diagram)	**FOAK (off-grid) 20 MWe**	**FOAK (off-grid) Dev. Time**	**FOAK (off-grid) LG + Reg. Return**	**FOAK (off-grid) Fleet Ops.**	**SMR (off-grid) 20 MWe**
Case	**10**	**11**	**12**	**13**	**14**
LCOE	$ 344.62	$ 296.20	$ 217.96	$ 197.59	$ 175.21
LCOE Break Down					
Construction Costs (excl. IDC)	38.2%	55.2%	50.1%	54.2%	47.7%
Development & Pre-Construction Costs	44.3%	24.4%	22.2%	24.0%	27.7%
Variable Costs	4.0%	4.7%	6.4%	7.0%	7.9%
Fixed Costs (includes capex)	10.3%	12.0%	16.3%	9.3%	10.5%
Decommissioning Costs	3.2%	3.8%	5.0%	5.5%	6.2%
Construction & Dev. Assumptions					
Capital Costs (excl. IDC, $M)	235	235	$ 235	235	196
Development & Pre-Construction Costs ($M)	126	72	$ 72	72	72
IDC (2018, $M)	-	-	$ 21	17	12
Development time (months)	84	72	72	72	72
Construction time (months)	48	48	48	48	36
Project Schedule (Dev to COD, months)	108	72	72	72	60
Capital Cost Assumptions					
Capital Cost, $000's/kW	11,732	11,732	11,732	11,732	9,815
Fixed O&M (includes Capex), $000's/kW-yr	280	280	280	145	145
Annaul Fixed Opex., $000's/year	5,600	5,600	5,600	2,900	2,900
Financing Assumptions					
Corporate Tax Rate	-	-	-	-	-
Equity Ratio	100.00%	100.00%	45.00%	45.00%	45.00%
Return on Equity	10.00%	10.00%	8.78%	8.78%	8.78%
Debt Ratio	-	-	55.00%	55.00%	55.00%
All-in Debt Rate	10.00%	10.00%	4.00%	4.00%	4.00%
WACC (nominal)	10.00%	10.00%	6.15%	6.15%	6.15%
WACC (real)	7.84%	7.84%	4.07%	4.07%	4.07%

Assumptions: Off-Grid Remote Community (3 MW) vSMR

vSMR Northern Community (Bridge diagram)	**FOAK vSMR (off-grid) 3 MWe**	**FOAK vSMR dev. Time**	**FOAK vSMR LG + Reg. Return**	**FOAK vSMR Fleet Ops.**	**vSMR 3 MWe**
Case	**15**	**16**	**17**	**18**	**19**
LCOE	$ 894.05	$ 629.75	$ 386.66	$ 310.22	$ 288.29
LCOE Break Down					
Construction Costs (excl. IDC)	21.2%	32.7%	24.2%	37.6%	30.8%
Development & Pre-Construction Costs	65.9%	49.1%	46.2%	50.1%	56.0%
Variable Costs	1.6%	2.2%	3.6%	4.5%	4.9%
Fixed Costs (includes capex)	10.6%	15.1%	24.5%	5.9%	6.4%
Decommissioning Costs	0.7%	1.0%	1.5%	1.9%	2.0%
Construction & Dev. Assumptions					
Capital Costs (excl. IDC, $M)	35	35	35	35	29
Development & Pre-Construction Costs ($M)	126	72	72	72	72
IDC (2018, $M)	-	-	12	12	9
Development time (months)	84	72	72	72	72
Construction time (months)	48	48	48	48	36
Project Schedule (Dev to COD, months)	108	72	72	72	60
Capital Cost Assumptions					
Capital Cost, $000's/kW	11,732	11,732	11,732	11,732	9,815
Fixed O&M (includes Capex), $000's/kW-yr	748	748	748	145	145
Annaul Fixed Opex., $000's/year	2,244	2,244	2,244	435	435
Financing Assumptions					
Corporate Tax Rate	-	-	-	-	-
Equity Ratio	100.00%	100.00%	45.00%	45.00%	45.00%
Return on Equity	10.00%	10.00%	8.78%	8.78%	8.78%
Debt Ratio	-	-	55.00%	55.00%	55.00%
All-in Debt Rate	10.00%	10.00%	4.00%	4.00%	4.00%
WACC (nominal)	10.00%	10.00%	6.15%	6.15%	6.15%
WACC (real)	7.84%	7.84%	4.07%	4.07%	4.07%

Assumptions: FOAK Sensitivity - Tornado diagram

FOAK SMR (Basecase - Tornado)	**FOAK (on-grid) +3% WACC**	**FOAK (on-grid) -3% WACC**	**FOAK (on-grid) Build 3 yr.**	**FOAK (on-grid) Build 5 yr.**	**FOAK (on-grid) -30% capital**	**FOAK (on-grid) +30% capital**	**FOAK (on-grid) 50 yrs. Life**	**FOAK (on-grid) 30 yrs. Life**	**FOAK (on-grid) O&M -10%**	**FOAK (on-grid) O&M +10%**
LCOE	$ 211.75	$ 120.87	$ 157.80	$ 167.73	$ 127.38	$ 197.96	$ 158.53	$ 171.81	$ 160.83	$ 164.51
LCOE Break Down										
Construction Costs (excl. IDC)	77.5%	64.1%	71.4%	72.8%	63.8%	77.3%	72.0%	72.5%	73.0%	71.3%
Development & Pre-Construction Costs	4.2%	4.2%	4.2%	4.2%	5.9%	3.2%	4.2%	4.2%	4.2%	4.2%
Variable Costs	6.6%	11.6%	8.8%	8.3%	11.0%	7.0%	8.8%	8.1%	8.7%	8.5%
Fixed Costs (includes capex)	8.7%	15.2%	11.6%	11.0%	14.4%	9.3%	11.6%	10.7%	10.3%	12.3%
Decommissioning Costs	3.1%	4.9%	4.0%	3.7%	4.9%	3.2%	3.4%	4.6%	3.9%	3.8%
Construction & Dev. Assumptions										
Capital Costs (excl. IDC, $M)	3,036	3,036	3,036	3,036	2,125	3,947	$ 3,036	3,036	3,036	3,036
Development & Pre-Construction Costs ($M)	126	126	126	126	126	126	$ 126	126	126	126
IDC (2018, $M)	-	-	-	-	-	-	$ -	-	-	-
Development time (months)	84	84	84	84	84	84	84	84	84	84
Construction time (months)	48	48	36	60	48	48	48	48	48	48
Project Schedule (Dev to COD, months)	108	108	108	108	108	108	108	108	108	108
Capital Cost Assumptions										
Capital Cost, $000's/kW	10,120	10,120	10,120	10,120	7,084	13,156	10,120	10,120	10,120	10,120
Fixed O&M (includes Capex), $000's/kW-yr	145	145	145	145	145	145	145	145	131	160
Annaul Fixed Opex., $000's/year	43,500	43,500	43,500	43,500	43,500	43,500	43,500	43,500	39,150	47,850
Financing Assumptions										
Corporate Tax Rate	-	-	-	-	-	-	-	-	-	-
Equity Ratio	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Return on Equity	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Debt Ratio	-	-	-	-	-	-	-	-	-	-
All-in Debt Rate	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
WACC (nominal)	13.00%	7.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
WACC (real)	10.78%	4.90%	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%

Appendix F: SUMMARY OF ASSUMPTIONS- MARKET SIZE CALCULATIONS

Domestic

- **Share spent in Canada:** Low (50%), High (75%)
- **Direct Labour Multiplier:** 0.000003225 jobs per dollar spent
- **Total Labour Multiplier:** 0.000003270 jobs per dollar spent
- **Total impact Multiplier:** 1.9X Direct Impact

International

Key Assumptions: SMRs can capture new markets that were previously inaccessible to nuclear as part of a global climate change-mitigation strategy:

- Provide baseload power to replace coal/natural gas for jurisdictions with small grids
- Replace diesel in off-grid islands/communities and off-grid mines
- Provide a non-emitting source of heat and power to some heavy industry applications.

To calculate the market share for each, we used the following approach:

On-Grid:

- Under their most stringent climate policy scenario, the IEA projects that 1150 GWe and 2297 GWe of coal and natural gas capacity respectively remains on grid in 2040.
- We assume that SMRs (previously not included in the IEA's World Energy Outlook Model) adds an additional mitigation option that can capture some of this residual emitting capacity.
- We assume SMRs capture 15% of the remaining coal and 5% of this remaining global gas capacity. SMRs ramp-up to their eventual 2040 capacities linearly starting in 2030.

Off grid Islands and mines:

- We build a database of remote islands still using diesel and built an estimate of the size of the SMR market from their respective generating capacities.
- The result is approximately 15.5GWe of capacity on 40 islands, all above 3.5MWe and with median size of 33MWe.
- Between 2030 and 2040, SMRs ramp up to eventually capture 24% of this total by 2040
- In addition, thousands of other communities and islands with smaller energy demands exist (IRENA identified 7GWe worth of communities with capacities < 1MWe). We assumed SMRs also capture a smaller fraction (5%) of this market.
- Based on historical data, about 15 new off-grid mines built per year. Given SMRs strong economics vs diesel, we assume they capture about 61% of new off-grid mines starting in 2030

Heavy Industry:

- The IEA projects 706Mtoe of coal used in industry globally in 2040.
- Assuming boiler efficiency of 33%, this results in 348GW which can be replaced by SMRs
- Assume 5% of this 2040 stock is captured by SMRs- Growth of 2 GW per year between 2030-2040