Analysis of the Case for Federal Support of Micro-Scale Nuclear Reactors to Provide Secure Power at U.S. Government Installations

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Executive Summary

In January of 2019, the University of Wisconsin began a study that examined the case for federal support of micro-scale nuclear reactors (microreactors) to provide secure power at U.S. Government Installations. Our study is composed of six parts.

Part 1: Estimate the market for new on-site generating capacity at federal government installations.

- There are 211 government installations with total average power requirements greater than 4 MW.
- Assuming that it would be reasonable to place a single microreactor for critical power needs, plus another technology for redundancy, at each of those sites, it is reasonable to treat a standard size of 2 MWe for a microreactor.
- With 211 sites, and assuming each site will replace at least one on-site generator over the next 10-20 years, we arrive at an estimate of about 211 generators as a potential market for new on-site generators in the next 10-20 years at federal installations. Larger sites may incorporate either larger generators, or multiples of these smaller microreactor generators.

Part 2: Survey of potential microreactor vendors.

Potential microreactor vendors were contacted to determine, based on publicly available information, microreactor conceptual design parameters and cost estimates. The UW team successfully contacted a dozen of these potential vendors and requested publicly available information on their designs. While public design information was limited, it is clear that these microreactor designs have the necessary characteristics that can be useful as on-site generators. Current cost estimates for First-of-a-kind plants (FOAKs), and Nth -of-a-kind plants (NOAKs), exist only as proprietary data, owned by the potential vendors. Thus, we base some of our cost estimates on those reported in a recent NEI study as well as other information in the public domain. Among these costs, the most significant is the estimate of the overnight capital cost of a microreactor. We also suggest crosscutting areas where future efforts can be focused to improve technical readiness and reduce costs.

Part 3: Economic Analysis

Having identified that there are potentially more than 200 installations large enough to host a microreactor as an on-site generator, we examined other technologies that might also serve on-site generators. A facilities manager interested in an enhanced level of resilience would likely choose the most cost-effective way to achieve a desired level of resilience. Our team modeled this decision-making process by calculating the annual cost that would be involved in achieving four levels of resilience using available technologies: a microreactor, diesel generators, natural gas generators, and renewables with storage (solar, wind and battery storage in various combinations). We assumed a surrogate site with total power demand of 4 MWe, and critical power demand of 2 MWe. The four "scenarios" for resilience are described below:

1. <u>Status quo.</u> A utility is primary supplier of electrical power. Backup generators are left in stand-by and run only if needed.
2. <u>The critical power is supplied by on-site generators running continuously, with the utility supplying the rest of the required power</u>. Resilience is achieved by having the utility and the on-site generators each serve as backup to the other.

3. The critical power is supplied by on-site generators running continuously, with the utility supplying the rest of the required power plus on-site backup. Enhanced resilience is achieved by having secondary on-site generators to back up the primary on-site generators that supply critical power. This approach eliminates need to depend on the utility up to the level of critical power, should the on-site generation become unavailable.
4. All power supplied on-site, with no power supplied by the utility. This basically takes an installation off-grid and requires on-site generators of 4 MWe plus backup generators. It provides resilience in that this approach is completely under the control of the installation.

The analysis shows that, for scenarios 2 and 3, a microreactor is more cost effective than diesel generators and might be able to compete with natural gas generators – as long as the microreactor can achieve a low capital cost, low operating costs, and is able to secure favorable financing. For scenario 4, taking an installation off-grid, a microreactor may actually be less expensive than a natural gas generator that uses Liquefied Natural Gas as the fuel.

Part 4: Case studies

Our analysis effort dealt with a standard site using generators sized at 2 MWe. The UW team also investigated several "real" sites in order to determine the way facilities managers actually plan for their future power requirements in the next 10-20 years. Two specific sites (Johnson Space Center, UW campus) were analyzed.

Actual sites are complicated. Any program to evaluate the potential for microreactors at specific sites will have to be addressed bottom-up – and that will need to be comprehensive. The UW team found that each facility manager has a unique set of constraints. Therefore, decisions about the installation of future on-site capacity will be made at the local level. Government agencies at upper levels cannot dictate planning at the level of individual sites.

We also considered the case where the government installation would seek to eliminate the use of fossil fuel as a source of needed electrical power. Specifically, we analyzed a case in which the site used only on-site power and, the power derived from carbon-free generators - hence the label "Green Site". Should the Administration wish to consider establishing carbon-free generators at government sites:

- It will be necessary to characterize sites by both their average power consumption and their peak power consumption. Each site is different. The size of the peak consumption dictates the amount of peaking power that would be needed to be supplied by renewable sources.
- In order to moderate the cost of a green site, it would be essential to develop microreactors to the point where they could achieve the target costs assumed in this study. Without a microreactor, renewables alone could indeed power the site, but at a much higher power cost.

Part 5: Regulatory Issues:

Under the Atomic Energy Act, nuclear reactors can be operated under the regulations and authorities of either the USNRC, DOE or DOD. Since microreactors are to be demonstrated for eventual commercial use, reactor licensing by the NRC is the recommended path. The NRC has different pathways to license reactors. Under current NRC regulations, there are two licensing approaches that the applicant can use:

- A two-step license process (10CFR-Part 50), which involves a Construction Permit (CP) followed by an Operating License (OL).

- A one-step license process (10CFR-Part 52), which involves a Combined Operating License (COL).
- A new approach (10CRF-Part 53) is under development by NRC for completion by the mid-2020's.

In order to gain the necessary operating experience to validate key design features, we expect that the first microreactors will be demonstrated at a DOE site as full-scale prototypes. A full-size prototype reactor could be the most direct and expeditious way to demonstrate the overall reactor performance for normal operation as well as testing during transients. NRC is currently working to resolve key policy issues associated with microreactors, e.g., siting, staffing, security and required accident analyses. We foresee that the most significant issue will be the ability to site microreactors near population centers with key insights developed from licensing research reactor facilities.

Part 6: Decision whether to go forward, and acquisition options for microreactor plants

Should the Government wish to pursue a program to encourage the use of microreactors at US Government installations, we recommend:

- A research program with milestones and a reasonable timeline that, if successful, would result in confidence that a FOAK plant could be built for about $12,000/kWe.
- A focused program in the Department of Energy capable of conducting this research program.
- A policy to coordinate the building one or more FOAK demonstrations when there is confidence that the cost of such plants would be around $12,000/kWe.

Then, assuming that the construction of FOAK plants leads industry to pursue further price reductions, and eventually offer NOAK plants at the target price used in this study, (~$4,000/kWe and reduced O&M costs), we recommend that:

- The Government decide on an organizational approach that could manage the construction and operation of a large number of microreactor generators (with a potential of possibly 200 plants).
- The chosen organization be accompanied by an appropriate financing mechanism that would provide the ability to recover revenues from the production of electricity by those plants.

If demonstration plants (possibly 5 to 10 such plants) are successful in validating the necessary economics, financing costs are still a major issue. If low financing costs around 2%-3% can be offered for a commercial purchase, then there is little difference between favoring private ownership and government ownership. If low-cost financing can only be obtained by having government ownership, then the economics would favor government ownership. If the government chooses government ownership, it might be appropriate to appoint a single agency as the owner of the plants.

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Introduction

On January 17, 2019, Idaho National Laboratory contracted with the University of Wisconsin for an "Analysis of the Case for Federal Support of Micro-scale Nuclear Reactors to Provide Secure Power at U.S. Government Installations"[i].

Today, Government installations around the country typically buy their power from utilities, then they use on-site backup generators for an added layer of reliability and security. Electricity from these on-site generators, typically diesel generators or natural gas generators, is usually more expensive than electricity purchased from utilities, nevertheless the availability of these back-up generators allows an installation to provide emergency power to critical power loads at these facilities in the event that power from the utility is not available for any reason.

As government installations have become ever more sophisticated (e.g., hospitals, data centers, rocket launch facilities, biology laboratories, nuclear accelerators, etc.) they become ever more dependent on a secure supply of electrical energy. Government agencies are concerned about this dependence and have started to focus ever more on the need for robust on-site generators as well as resilience, the ability to recover during an outage.

Today, on-site generators are typically held in standby, to be used only for emergencies. This study focuses on a transition that will inevitably take place over the next 10-20 years. During that time, installations will need to replace aging on-site generators and many of the installations will also upgrade their on-site distribution systems, i.e., microgrids. This new approach to the distribution of power on a site offers new opportunities for the use of on-site generators. Instead of merely being used as backups, the generators can be used as a complement to power purchased from a utility, providing continuous reliable power on the sites. By using these generators in a new configuration, it will be also possible to enhance the resilience of these installations,

A priori, there are two types of installations: those that are connected to an electric grid (on-grid), and those that are not (off-grid). Data collected during this study leads to the conclusion that practically all federal government installations are on-grid, a finding that results in our analysis being focused on on-grid facilities. There are some government installations that are off-grid, e.g., weather stations, satellite tracking stations. However, their power requirements are quite small (<1MWe) and thus not a candidate for the siting of a microscale nuclear reactor (microreactor).

While this study focuses on the application of microreactors to Federal Government facilities, there are likely commercial applications of the same technology in the private sector and for state and local government facilities. We are aware of a notable population of off-grid non-government facilities: e.g., remote towns in sparsely populated regions of the United States (e.g., Alaska), private companies, especially in the mining industry, off-shore rigs and platforms, and marine applications. Nevertheless, with our focus on Government installations, these other installations are beyond the scope of this current study.

At the same time, the approach to making technical choices for Government installations may also be relevant to making decisions for these non-federal installations. Thus, this study may provide a window into the potential use of microreactors for use in an even larger market: i.e., supplying off-grid power to non-federal entities. Thus, the federal government could be one of the first consumers of microreactors for on-site secure power.

The focus for this current study is to determine the potential role of microreactors in providing secure power for government installations. We define "secure power" to mean the ability of an installation to operate under conditions when the external source of utility power becomes unavailable. We also equate this definition to that of the concept of "Resilience"[ii].

This analysis assumes that the Federal Government will be an early consumer of the emerging technology and would make the decision to do so based primarily on the energy resilience benefits microreactors, but such decisions exist in a broader energy and technology development policy ecosystem. On the first point, this assumes that the Government will be willing to take on the risk of deploying a new technology without a long-standing operational record. Adopting such a role is appropriate for the Government, and can have important technology policy implications, particularly if the Government is willing to make early commitments based on the vendors being able to reach particular milestones (see NASA-COTS). The willingness of the Government to make such a commitment may depend on demonstrating a commercial market that is substantially larger than the Government facility market we consider in this study. The existence of such a market may depend on microreactor technology achieving additional technical requirements that increase the attractiveness of the technology to non-Government consumers. On the second point, there may be other benefits of adopting microreactors beyond resilience. Most prominently, growing concern for carbon emissions may provide additional incentive for both Government and private facilities to deploy new low-emission energy technologies, including microreactors. Consideration of this broader policy ecosystem is outside the scope of this study and our findings will be largely independent of such considerations.

Resilience – An Operational Definition

When a utility plans to purchase new generating equipment, the utility certainly considers the predicted reliability and availability of the technical alternatives under consideration. These considerations, nevertheless, are not the same as planning for the <u>resilience</u> of the power generating system. Operationally, a utility faces two problems with maintaining service. If a power line or switching gear goes down, a utility rushes to fix the problem and copes with the outage in the meantime. If a generator goes down, the utility buys power from the grid, which acts as the backup supply until the utility can fix the problem with the generator. The term "resilience" is subsumed in the ability of the utility to restore power as quickly as possible.

Government installations can face a different set of problems and "resilience" has become a catch-all phrase, sometimes referring to several different criteria: the ability to repel, resist, and absorb a disruption in an electrical system, the ability to adapt to various disruptions, and the ability to recover quickly – all with the ultimate goal of keeping government services available during an outage. At the present time Government agencies, concerned with the ability to sustain operations in times of stress, continue to provide guidance to their installations as to the meaning of the term and ways to improve resilience. Today it seems that Government agencies depend on the work of the Department of Defense (DOD) to define the term and provide guidance on ways to ensure resilience. The Department of Defense defines the term[iii] "energy resilience" as, "The ability to prepare for and recover from energy disruptions that impact mission assurance on military installations."[iv] (Note that this is a short version of the definition provided in the US Code.[v]) DOD then augments this definition by requiring that, "DOD Components shall plan and have the capability to ensure available, reliable and quality power to continuously accomplish DOD mission from military installations and facilities"[vi]. DOD then uses this definition as the basis for DOD's policy memorandum of May 30, 2018, "Installation Energy Plans – Energy Resilience and Cybersecurity Update and Expansion of the Requirement to All DOD Installations[vii].

These definitions and further refinements, nevertheless, are actually policy guidance. The <u>operational</u> definition of resilience, i.e., what it takes "to prepare for and recover from energy disruptions", is acknowledged to be dependent on the needs of each installation, and the Assistant Secretary of Defense avoids any prescriptive orders that would impact the DOD facilities. Nevertheless, recognizing the need for an operational definition, a study by Lincoln Labs in 2016[viii] attempted to quantify the definition. That study refers to "the availability of power to on-site critical energy loads during times of grid outage". In the current study, we adopt the definition suggested in the Lincoln Lab study, i.e., an adequate level of resilience implies <u>on-site generating capacity equal to the critical power requirements of an installation</u>.

But an operational definition needs to be yet even more specific. First of all, critical power requirements are somewhat subjective; they are arrived at by consensus. For the purpose of this study, the critical power requirement of an installation means a level of power that needs to be maintained in order to allow the federal installation to continue to deliver its mission during a time when primary power is unavailable for extended periods of time. For on-grid facilities, the focus of this study, this means the minimum power level needed during a disruption in power from the utility.

Each installation will have its own definition of critical power. Hospitals need to maintain a minimum level of power to support services to patients, but not necessarily to keep the lights on in the cafeteria or the library. Data centers need a critical level of power to keep the computers running, but not necessarily for lights in the parking lot.

Given the ability of an on-site generator, or generators, to satisfy critical demand, there is still an issue of the type of problem that backup generators are meant to solve. And for all the possible scenarios, the issue seems to devolve into the expected time of an outage. There are costs associated with providing backup power. An installation needs to decide how long it might be required to function on backup power and needs to consider the attendant costs of providing backup power. For example, if diesels provide the backup power, how much fuel needs to be in on-site storage? If gas turbine generators provide the primary power, how much on-site natural gas storage (or LNG) needs to be available in case there is a disruption in the gas pipeline?

DOD has issued criteria stating that backup supplies need to be available for seven days[ix], with provision for sites to modify if "mission operations require a different operational duration". For Army Secure Critical Missions, Army requires storage of energy and water for 14 days. Specifically, DOD assumes the reliability of the backup generators.

For the current study, in our view, this time period might not be sufficiently long. For example, the Camp Fire in California caused a localized power outage for about 53 days[x]. If such an outage can happen once, it can happen again, and adequate resilience should at least be able to deal with events that have actually happened. Nevertheless, we realize that the only official guidance comes from DOD and, for the analysis in this study, we adopt that DOD criteria, i.e., adequate resilience involves being able to endure an outage of 7 days.

There is one final attribute that goes into our definition of resilience: redundancy. Let's assume a simple case in which an installation has a flat demand for power at a level of 10 MWe. Let's also assume that, in the next 10-20 years, the installation has put in place a micro-grid so that a single backup generator, or a few such generators, can supply the entire installation[xi]. If the installation were to install a single backup generator of 10 MWe, there would remain a probability that the generator might experience problems.

Thus, for enhanced resilience, to provide insurance against the failure of a single backup generator, it would make sense to install a set of smaller generators rather than a single large generator. For example, a facility requiring 10 MWe of backup power, resilience would be enhanced by installing two 5-MWe generators rather than a single 10-MWe generator, and further enhanced by installing four 3.3-MWe generators (for example) to provide redundancy.

Thus, we adopt several system attributes as components of an adequate resilient backup power system:

- Power, adequate to supply critical power demand.
- Availability, a fuel supply adequate to supply critical demand for weeks.
- Redundancy, to protect against the possible failure of a single backup generator.

Study Approach

This study was conducted in five primary tasks. The first task, described in Chapter 1, seeks to assess the size of the potential market for installation of microreactors at Government facilities and better understand the system requirements for such deployments. The second task, described in Chapter 2, reviews the technology offerings from a broad array of potential microreactor vendors with the goal of assessing the suitability of those technologies to meet the demand identified in task 1. The largest task (Task 3) performs a series of economic analyses of different on-site energy generation scenarios across different technologies. Chapter 3 compares the system costs of different technology mixes, including fossil fuels, renewables with energy storage, and microreactors, in four different deployment scenarios, each with different inherent resilience. Chapter 4 focuses on a higher fidelity low-emission, multi-technology solution for a single site, optimizing the mix of technologies depending on their cost assumptions. Chapter 5 considers two additional case studies based on real facilities and their current and expected energy demand profiles. Task 4 (Chapter 6) examines regulatory issues related to the deployment of microreactors. In Chapter 7, the final task describes programmatic options for the demonstration and deployment of microreactors at Government facilities, including aspects of research and development, demonstration and procurement. A series of appendices provides supporting information for the analysis that is summarized in these chapters.

Chapter 1

Estimate the Size of the Market for New On-Site Generating Capacity

Government Installations – The Market

Over the next 10-20 years, government installations will confront the need to purchase new power generating capacity, replacing aging on-site generators. The size of the market for new on-site generators thus depends on the number of new generators that installations plan to purchase over the next 10-20 years. Today the technology choices for on-site generators are diesels, gas turbines, solar and wind, and each has implications for resilience. Diesels require fuel storage, while natural gas generators require a connection to a gas utility. Over the next 10-20 years, microreactors may provide a technical alternative that can enhance resilience at government installations and will not simply be a replacement for on-site generators. Depending on the eventual cost, microreactors may become a preferred technology of choice as a facility manager looks to acquire new on-site continuous power generating capacity that will also increase the resilience of the site beyond merely having emergency backup generators.

Current microreactors concepts are being designed with capacities ranging from 1 MWe to over 10 MWe. Based on thermal efficiencies, that translates into a minimum thermal power of 2-3 MWth. Thus, before considering the need for replacement of on-site power, we start by identifying the number of government installations with power requirements in this range.

The Federal Energy Management Program (FEMP) publishes data for energy use at government facilities. The database is updated regularly, so for the current year it is a moving target. In total, FEMP lists 27 agencies that report energy use. For FY 2018, the last year with complete data, FEMP provides data on 27 agencies[xii]. Total energy use for these agencies (both heat and power) is shown below in Table 1.1.

Please note one point about this table. For each agency, total energy use is dominated by purchased energy, which can be either a fuel (e.g., natural gas), or electricity. Some of the purchased power may be used for heat, e.g., natural gas supplied to on-site boilers for heating the physical plant. There may even be cases where cogeneration plants on-site are used to supply heat, with the attendant electricity produced and then used to off-set power from the utility.

In order to determine the typical ratio of electric BTU to Non-electric BTU, we examined the FEMP database as well as contacted several individual agencies (e.g., NIH, NIST, NASA centers). Federal agencies report this breakdown between heat and power at the agency level and the FEMP data summary is shown in Table 1.2 below[xiii]. As one can see the fraction of energy use that is in the form of electricity ranges widely across agencies with an average of about 50% for all civilian agencies. In addition, the individual agencies and specific installations we contacted reported similar results with a wide range (30-70%) for the fraction that was electrical energy. Based on these data below, for the purpose of this study, we make a simplifying assumption that the electric demand is about 50% of total energy demand.

Table 1.1: FEMP Data Summary Report on Energy Use (mmBTU) by Agency in FY2018

Agency	# of Active Covered Facilities	Annual Facility Energy Use (Million Btu)	Annual Facility Energy use (MWh)	Average power (MW)
Federal Government Total	**7881**	**229,957,942**	**67,396,818**	**7,694**
Department of Defense (DOD) *	581	128,788,166	37,745,652	4,309
Department of Veterans Affairs (VA)	171	27,466,271	8,049,904	919
Department of Energy (DOE)	42	18,774,511	5,502,494	628
General Services Administration (GSA)	183	11,711,729	3,432,512	392
Department of Justice (DOJ)	95	10,279,723	3,012,815	344
Department of Health and Human Services (HHS)	81	7,134,528	2,091,011	239
National Aeronautics and Space Administration (NASA)	12	4,955,365	1,452,334	166
Department of Transportation (DOT) *	352	3,202,634	938,638	107
Department of Agriculture (USDA) *	68	3,017,502	884,379	101
Department of Homeland Security (DHS) *	177	2,788,048	817,130	93
Department of the Interior (DOI)	383	2,771,980	812,421	93
Department of Commerce (DOC)	6	2,035,749	596,644	68
Department of Labor (DOL)	64	1,481,712	434,265	50
United States Army Corps of Engineers (USACE)	41	1,172,283	343,576	39
Tennessee Valley Authority (TVA)	88	1,071,734	314,107	36
Environmental Protection Agency (EPA)	15	789,879	231,500	26
Department of the Treasury (TRSY) *	16	772,110	226,292	26
Social Security Administration (SSA)	8	520,531	152,559	17
Department of State (STATE)	11	436,192	127,840	15
National Archives and Records Administration (NARA)	8	375,900	110,170	13
Federal Deposit Insurance Corporation (FDIC)	7	178,657	52,361	6
Department of Housing and Urban Development (HUD)	1	88,106	25,822	3
Office of Personnel Management (OPM)	3	73,349	21,497	2
Nuclear Regulatory Commission (NRC)	2	40,430	11,849	1
Railroad Retirement Board (RRB)	1	30,852	9,042	1
Smithsonian Institution (SI) *	10		0	0
United States Postal Service (USPS) *	5455		0	0

Table 1.2: FEMP Data Report on Site-Delivered Energy Use (mmBTU) by Agency and Energy Type in 2018

Agency	Electricity	Fuel Oil	Natural Gas	Purch Steam	Purchased Renewable Energy	On-Site Renewables And Adjustments	Other Facility Energy	Facilities Subtotal
Government Total	179,966	17,177	125,787	7,886	2,916	9,525	3,245	354,295
Defense	*100,603*	*13,520*	*70,371*	*4,352*	*1,477*	*4,899*	*479*	*202,832*
Civilian Agencies Subtotal	*79,363*	*3,657*	*55,416*	*3,534*	*1,439*	*4,627*	*2,766*	*151,463*
Veterans Affairs	11,347	455	14,421	1,196	0	591	347	28,361
Energy	15,236	281	6,720	74	709	2,587	198	25,893
Postal Service	15,214	820	5,910	145	0	9	1	22,196
GSA	7,634	141	5,844	826	0	116	975	15,535
Justice	4,896	116	6,565	95	127	334	24	12,185
HHS	2,811	308	6,350	73	77	12	36	9,715
NASA	4,338	57	2,457	0	262	524	0	7,705
DHS	2,684	509	1,059	140	13	32	69	4,596
Transportation	3,174	342	650	17	22	28	2	4,251
Interior	1,961	153	959	69	33	135	420	3,779
Agriculture	1,625	79	799	212	1	22	228	3,118
Commerce	1,726	0	1,046	45	0	0	0	2,818
Labor	878	78	775	47	14	4	59	1,854
USACE	1,086	213	201	0	22	96	0	1,636
Treasury	897	41	318	268	0	0	0	1,524
TVA	1,314	0	1	0	0	112	0	1,428
Smithsonian	629	7	353	186	0	5	182	1,362
EPA	355	15	306	79	1	6	195	958
SSA	509	10	205	0	15	7	0	745
Other*	472	29	152	15	11	0	0	678

As an example of facility-level data, Table 1.3 below shows the FEMP data for a specific agency, the Department of Energy.[xiv] Department of Energy (DOE) reports publicly disclosed data on 37 out of a total of 42 facilities. The annual power requirements of the facilities vary from (73MW) at Oak Ridge National Laboratory to essentially zero at the five smallest sites. We would also note that well over half of these DOE laboratories and facilities (22 of the 37) consume a sizable amount of energy that fits the profile that could be supplied by an on-site microreactor.

Table 1.3: FEMP Data Report on Energy Usage by Department of Energy Facilities in FY2018

Facility Name	Number of Buildings Metered for Electricity	Annual Facility Energy Use (Million Btu)	Annual Facility Energy use (MWh)	Average power (MW)
Los Alamos National Laboratory	120	2,145,721.00	628,874.85	71.79
Oak Ridge National Laboratory	208	2,095,856.00	614,260.26	70.12
Brookhaven National Laboratory	308	1,575,124.00	461,642.44	52.70
Argonne National Laboratory	75	1,507,302.00	441,764.95	50.43
Y-12 National Security Complex	83	1,425,484.00	417,785.46	47.69
Lawrence Livermore National Laboratory	361	1,334,715.90	391,182.85	44.66
Fermi National Accelerator Laboratory	24	1,055,333.00	309,300.41	35.31
Sandia National Laboratory - New Mexico	102	870,869.70	255,237.31	29.14
Savannah River Site	0	786,480.90	230,504.37	26.31
Portsmouth Gaseous Diffusion Plant	151	688,449.60	201,773.04	23.03
Stanford Linear Accelerator Center	24	663,641.00	194,502.05	22.20
Idaho National Laboratories-Scoville	0	538,166.00	157,727.43	18.01
Lawrence Berkeley National Laboratory	45	486,061.00	142,456.33	16.26
Thomas Jefferson National Accelerator Facility	29	444,980.90	130,416.44	14.89
National Security Campus	7	424,135.00	124,306.86	14.19
Pantex Plant	73	350,085.90	102,604.31	11.71
Pacific Northwest National Laboratory	48	339,090.00	99,381.59	11.34
Hanford/Richland Operations Office 100	24	303,573.30	88,972.25	10.16
National Renewable Energy Laboratory	27	156,532.50	45,877.05	5.24
Sandia National Laboratory - California	24	134,128.10	39,310.70	4.49
Headquarters - Forrestal	1	127,569.00	37,388.34	4.27
Nevada National Security Site	177	96,643.60	28,324.62	3.23
Princeton Plasma Physics Laboratory	6	90,925.00	26,648.59	3.04
Headquarters -Germantown	1	72,267.00	21,180.25	2.42
Idaho National Laboratories-Idaho Falls	104	69,291.00	20,308.03	2.32
National Energy Technology Laboratory - Pittsburgh Office	68	68,794.10	20,162.40	2.30
North Las Vegas Facility (NLVF)	0	58,598.00	17,174.09	1.96
Ames Laboratory	8	57,625.00	16,888.92	1.93
National Energy Technology Laboratory - Morgantown Office	0	39,349.20	11,532.59	1.32
Oak Ridge Office	16	21,071.50	6,175.70	0.70
Office Of Scientific And Technical Information	1	19,291.40	5,653.99	0.65
Waste Isolation Pilot Plant	15	19,132.60	5,607.44	0.64
Paducah Gaseous Diffusion Plant	0	11,526.00	3,378.08	0.39
National Energy Technology Laboratory - Albany	0	11,161.50	3,271.25	0.37
Oak Ridge Institute For Science And Education	7	10,202.00	2,990.04	0.34
National Training Center	0	6,919.20	2,027.90	0.23
Legacy Management Sites	35	1,477.10	432.91	0.05

Of the 1829 civilian facilities reported by FEMP for 2018, only 56 (3%) have energy needs above 10 MW-y. These major energy users are found in 10 different agencies. They comprise research facilities (DOE), stand-alone heating plants (GSA), office buildings, prisons, hospitals, etc. As for the rest, analysis of the FEMP database indicates that 70% of Government sites require energy less than 30,000 mmBTU annually (1 MW-y).

Given the details of the FEMP data, several patterns became evident. First, about half of the energy consumed at a site was electric. Second, about half of the total electric demand at a site was the critical electric energy needed (within a wide margin). Thus, a site requiring 4 MW total, would require 2 MWe of electricity, and the critical power needed would be half that, about 1 MWe. Since microreactors are currently being designed to be greater than about 1 MWe, we concluded that such reactors would be appropriate for satisfying the critical energy needs of sites that have a total energy demand greater than 4 MW-y. Based on an analysis of the FEMP database, this suggests that at least 211 civilian federal installations could be viable candidate sites.

In addition, there are certainly smaller federal installations with energy needs that are primarily electrical power, where there is almost no significant demand for heat. Some of these facilities might also be candidates for installing reactors as small as 1 MWe. If we include such facilities in the potential market for microreactors, the number of viable "candidate" installations increases further. Nevertheless, given that we do not know the number of these small installations that might qualify, we take a conservative approach in this analysis and refer to the potential market as being greater than 200 facilities.

Our next objective would be to estimate the number of installations that are on-grid versus off-grid. This information is not directly available from the FEMP database. This required us to contact the individual agencies and ask them to provide this information. In some cases, it required us to locate the specific installation and confirm if they were serviced by an electric utility. As shown in Table 1.4, only the Justice Department would not respond. However, based on our analysis, these installations with major energy usage appeared to be on-grid. We also surveyed maps to determine whether we could find federal facilities that were in remote areas, with annual energy use above 4 MW-y. The result of this search was to re-affirm the conclusion that there are no federal facilities, with annual energy use above 4 MW-y, that are off-grid facilities.

Finally, we looked at FEMP data for federal facilities in particular remote areas. Our conclusion is that installations in remote areas tend to be small, too small to be able to use a microreactor. As an example, the information for Alaska is shown below (Table 1.5). While FEMP reports 50 installations in Alaska[xv], only one of those installations is large enough to be able to make use of a microreactor. This installation is the U.S. Coast Guard Base in Kodiak. This base is on Kodiak Island and, with significance to the current study utility rates are almost 200% above the Alaskan state average.

Table 1.4: Distribution of Energy Needs for Government Civilian Agencies (Power > 5 MW in a year)

AGENCY	No of facilities with power >5 MW	No of facilities off-grid >5 MW	Comments on Facilities >5 MW (equals 150 billon BTU/yr)
DHS - Homeland Security	6	0	Coast Guard Bases
DOC - Commerce	3	0	NIST is major on-grid facility
DOE - Energy	19	0	DOE national labs on-grid
DOI - Interior	1	0	HQ in Washington DC
DOJ - Justice	18	*no response*	No official response on data
DOT - Transportation	2	0	Bldg. in Washington DC
GSA - General Services Admin.	8	0	HQ and major city bldgs.
HHS - Health Human Services	14	0	NIH
NASA - Space Agency	8	0	See BB Notes
NRC - Nuclear Reg. Commission	0	0	Washington DC
SSA - Social Security Admin.	1	0	HQ in Washington DC
TRSY - Treasury	3	0	Printing in Washington DC
USDA - Agriculture	2	0	HQ and Res. Center in DC
DOL - Labor	0	0	HQ in Washington DC
EPA - Environmental Prot. Agency	1	0	Centers in RTP/Cinn/U.Mich
FDIC - Fed. Dep. Insur. Corp.	0	0	none
HUD - Housing Urban Development	0	0	none
NARA - National Archives	1	0	HQ in College Park, MD
OPM - Office Personal Management	0	0	none
RRB - Railroad Retirement Board	0	0	none
SI - Smithsonian Institute	1	0	Downtown Washington DC
TVA - Tennessee Valley Authority	0	0	Fossil Fuel Plants
USCAE - Corps of Engineers	1	0	Res. Center in Vicksburg, MS
USPS - Postal Service	1	0	Facilities in Major Cities
VA - Veterans Administration	81	0	Hospitals (none off-grid)
Total	**168**	**0**	

Table 1.5: Listing of Government Civilian Installations in Alaska Ranked by Annual Energy Needs

Agency	Sub-Agency	Facility Name	Annual Facility Energy Use (Million BTU)	Annual Facility energy use (MWh)	Average power (MW)
DHS	*United States Coast Guard (USCG)*	*Base Kodiak*	*241,049.50*	*70,648*	*8.06*
GSA	Region 10 (Region 10)	Anchorage FB/USCT & Annex	47,736.20	13,991	1.60
DOT	Federal Aviation Administration (FAA)	Middleton Island Airport	38,186.20	11,192	1.28
DOT	Federal Aviation Administration (FAA)	Anchorage ARTCC	22,699.30	6,653	0.76
GSA	Region 10 (Region 10)	JUNEAU FEDERAL BLDG	21,724.00	6,367	0.73
DHS	United States Coast Guard (USCG)	AIRSTA Sitka	21,352.50	6,258	0.71
DOI	National Park Service (NP)	Denali National Park & Preserve – front country	21,205.40	6,215	0.71
DOL	Department of Labor (DOL)	ALASKA	19,938.40	5,844	0.67
DOT	Federal Aviation Administration (FAA)	Biorka Island Remote Facilities	18,277.40	5,357	0.61
DOC	National Oceanic and Atmospheric Administration (NOAA)	NOAA NESDIS FCDAS Gilmore Creek	11,685.90	3,425	0.39
DOT	Federal Aviation Administration (FAA)	Johnstone Point Airport	11,591.20	3,397	0.39
DOT	Federal Aviation Administration (FAA)	Anchorage International Airport	10,388.00	3,045	0.35
DOT	Federal Aviation Administration (FAA)	Level Island Remote Facilities	9,965.20	2,921	0.33
DOT	Federal Aviation Administration (FAA)	Sisters Island Remote Facilities	7,638.10	2,239	0.26
DOT	Federal Aviation Administration (FAA)	Moses Point Remote Facilities	7,638.10	2,239	0.26
DHS	United States Coast Guard (USCG)	Base Ketchikan	7,623.20	2,234	0.26
DOT	Federal Aviation Administration (FAA)	Bethel Airport	7,612.00	2,231	0.25
DOT	Federal Aviation Administration (FAA)	Kenai Municipal Airport	7,556.40	2,215	0.25
DOT	Federal Aviation Administration (FAA)	Turnagain SSC	7,489.70	2,195	0.25
DOI	Bureau of Land Management (LM)	Campbell Tract Facility	5,959.50	1,747	0.20
DOT	Federal Aviation Administration (FAA)	Dillingham Airport	5,453.70	1,598	0.18
DOT	Federal Aviation Administration (FAA)	Cold Bay Airport	5,300.10	1,553	0.18
DOT	Federal Aviation Administration (FAA)	King Salmon Airport	5,099.70	1,495	0.17
DOT	Federal Aviation Administration (FAA)	Fairbanks International Airport	4,910.20	1,439	0.16
DOI	Department of the Interior (HQ) (DOI)	Aviation Management Alaska Regional Office	4,860.80	1,425	0.16
DOI	Fish and Wildlife Service (FW)	Yukon Delta NWR	4,008.60	1,175	0.13
DOI	Fish and Wildlife Service (FW)	Alaska Peninsula/Becharof NWR Complex	3,698.40	1,084	0.12
DOI	Fish and Wildlife Service (FW)	Kenai NWR	3,427.20	1,004	0.11
DOI	Fish and Wildlife Service (FW)	Alaska Maritime NWR	3,093.40	907	0.10
DOT	Federal Aviation Administration (FAA)	Merrill Field Airport	2,497.30	732	0.08
DOT	Federal Aviation Administration (FAA)	Fort Yukon Airport	2,444.30	716	0.08
DOT	Federal Aviation Administration (FAA)	Nome Airport	2,416.30	708	0.08
DOT	Federal Aviation Administration (FAA)	Northway Airport	2,378.60	697	0.08
DOT	Federal Aviation Administration (FAA)	Fairbanks AFSS	2,329.10	683	0.08
DOT	Federal Aviation Administration (FAA)	Ralph Wien Memorial Airport	2,240.60	657	0.07
USPS	United States Postal Service (USPS)	ANCHORAGE - DOWNTOWN STATION *	*1,223.80*	359	0.04
DOT	Federal Aviation Administration (FAA)	Merle K (Mudhole) Smith Airport	1,138.30	334	0.04
DOT	Federal Aviation Administration (FAA)	Aniak Airport	1,067.00	313	0.04
DOI	Bureau of Land Management (LM)	Glenallen Headquarters	951.3	279	0.03
DOI	Fish and Wildlife Service (FW)	Kodiak NWR	917.8	269	0.03
DOI	Fish and Wildlife Service (FW)	Motor Vessel Tiglax	124	36	0.00

To summarize:

1. Sites with annual energy requirements above about 120 billion BTU (4 MW-y) are viable candidates for employing a microreactor for secure power.
2. Over 200 federal installations have energy needs above this level and fit this usage criterion.
3. Essentially all the installations reporting to FEMP with large energy use are on-grid.

At this point in the study, we need to further refine the characteristics of those installations that might make use of a microreactor for secure power. Given the data above, we now present a set of reasonable assumptions that form the basis of our subsequent analyses.

Assumptions Necessary to Estimate the Size of the Market

We start with the assumption that on-site generators are needed to provide power sufficient to satisfy the critical power needs of an installation – not the total need for power. The critical load is the amount of power needed to maintain critical infrastructure during an outage, e.g., hospitals, data centers, etc. For installations that do not plan major expansions in the future, it is reasonable to assume that their current on-site generators cover their critical load. Thus, we assumed that, in general, replacements for on-site generating capacity will provide the same power as is currently provided by on-site back-up generators. This is not true where sites are planning for major expansions over the next 10-20 years. In such cases site planners will need to estimate their future requirements for critical loads – and the sites may or may not have the necessary plans in place at the current time. We deal with this unknown by assuming that, in general the critical load may be about half the total load.

At this point, we consider a representative installation (a surrogate site) that might be appropriate for a microreactor, with total energy requirements of about 240,000 mmBTU (or approximately 8 MW-y). The electrical share of this energy demand requires a 4 MWe generation source. Going back to our criteria for increased resilience based on diversity to protect against a common-mode failure of the on-site generators, we end up with a logic that requires at least two types of on-site generators, using different technologies, and each must generate enough power to satisfy the need for critical power, to protect against the other one going down. If there are at least two on-site generators being able to produce power at the level of critical power, we have doubled the need for on-site capacity. Not that both would be in constant use. One generator would provide critical power on an on-going basis and the other would operate in a stand-by mode should the first on-site generator fail. To the extent that the economics are competitive, a microreactor might be the technology of choice for providing continuous power at the critical level, while a fossil fueled generator or energy storage might provide the needed backup power. As a result, backup power for the smallest federal civilian installations would involve two generators, utilizing different technologies, at about 2 MWe each.

In addition, we assume that a microreactor of this size can satisfy the heat load at a typical facility. This assumption is reasonable since the thermal efficiency of most designs is 33-40%. If that is not the case the reactor size can be increased to satisfy the heat load and the excess electricity can be used on site.

These assumptions are to be used as nominal conditions for our economic analyses and are also important for the rest of this study. For example, the regulator (likely the Nuclear Regulatory Commission) may demand that reactors be demonstrated as full-scale prototype reactors in order to demonstrate acceptable operability and safety in order to receive an operating license. Thus, it would be reasonable to demonstrate reactors sized to produce a few megawatts of power. Once these reactors are licensed, vendors could be able to scale up the size or the number of modules to match the needs of particular installations.

Direct Contacts with Federal Agencies

Given that the information available from the FEMP database is integrated over many installations, we contacted agencies and installations and learned from them how they manage their energy consumption, and what their plans might be for upgrades over the next 10-20 years.

We first contacted the staff members at agency headquarters who are charged with reporting energy data to FEMP. The list of those personnel is shown in Appendix A. We informed them of this project at the behest of DOE-NE. In some cases, DOE Headquarters personnel forwarded our request for information to the appropriate federal installations. For example, DOE laboratory information required a formal Data Call from DOE Headquarters personnel. In cases where we had contacts at the federal installation, we followed up by phone interviews. In some cases, we received the requested information. In other cases, site personnel refused to provide the information. The status of these attempts to obtain information is shown in Table 1.6 below for facilities with large energy usage, i.e., 300,000mmBTU (10 MW-y).

Table 1.6: Summary of Responses from UW Survey of Government Agencies

Agency	Response
DHS – Homeland Security	FEMP information at facility level
DOC – Commerce	Details provided at facility level
DOE – Energy	Data calls for NNSA & Science Labs
DOI – Interior	FEMP information at facility level
DOJ – Justice	No formal response provided
DOT – Transportation	Provided information as requested
EPA – Environ. Protection Agency	FEMP information at facility level
GSA – General Services Admin.	Some details provided at facility level
HHS – Health & Human Services	Details provided at facility level
NASA – Space Agency	Details provided at facility level
NRC – Nuclear Regulatory Comm.	Details provided at facility level
SSA – Social Security Admin.	Provided information as requested
TRSY – Treasury (Bureau of Engraving)	Details provided at facility level
USDA – Agriculture	Some details provided at facility level
USACE – Corps of Engineers	FEMP information at facility level
USPS – Postal Service	FEMP information at facility level
VA – Veterans Administration	FEMP information at facility level

The input received from each of the installations is shown in 0. In addition, we sought much more detailed information from several installations: the University of Wisconsin campus (a surrogate site of convenience), and the NASA Johnson Space Flight Center. More comprehensive information on those sites is shown in Chapter 5 on case studies.

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Chapter 2
Survey of Potential Vendors

The purpose of this part of the study was to contact potential vendors and determine, based on publicly available information, the microreactor conceptual designs, design key parameters, cost estimates and whether their microreactor designs may be consistent with the use of these reactors as on-site generators.

As on-site generators, microreactors will have to operate as part of an on-site micro-grid that is designed as a generation and distribution system for power on government installations. This operating environment will impose requirements on the microreactors such as their overall size, their ability to follow loads, their fueling requirements, and the number of personnel needed to operate them. In an attempt to obtain similar data for a Congressional Report, DOE has already identified many of the requirements that will be essential if a microreactor is to be a successful component of the electrical system on a Government facility[xvi].

Our UW team started with an initial list of design parameters that was consistent with those initially identified by the DOE staff. We also developed a list of microreactor developers and vendors based on those listed in the recent GAIN Advanced Nuclear Directory[xvii] (see Appendix C) as well as those developers participating in the 2019 Microreactor Workshop at Idaho National Laboratory[xviii]. We expanded the list of design parameters, successfully contacted a dozen of these potential vendors, and requested publicly available information on their designs. The responses from the vendors are shown in Appendix D, and indicate varying degrees of design information and technical maturity of the designs.

The responses show a lack of publicly available information that would be necessary for DOE to determine which designs might be appropriate for use as on-site generators. Specifically, many of the vendors were not able or willing to provide publicly available information. These characteristics include:

- Expected capacity factors.
- Ability to follow load (ramp up/ramp down rate).
- Type of power conversion system used in the design.
- Ability to meet the switchyard requirements that may be imposed on them.
- Physical size of their proposed plants (e.g., their exposure above and below grade.)
- Expected ultimate heat- sink (air or water).
- Requirements for refueling.
- Requirements for decommissioning.
- Requirements for on-site personnel.
- Estimated R&D development costs for their design.
- Estimated overnight capital cost for a plant ($/kWe installed).
- Estimated fuel cycled design and cost.
- Estimated resilience to natural and man-made external events.

This is not to say that the vendors do not have this information, although some may not. Nevertheless, such information directly relates to the state of maturity of a particular design. If the information is not available, a company would need to do additional R&D in order to advance the design to the point where DOE could even evaluate the merits of their design for possible prototype demonstration.

It could be that companies are simply withholding their design information in order to maintain a competitive edge. For example, OKLO provides a limited amount of public information, yet they have been dealing with NRC, and recently applied for a Combined Operating License. It is noteworthy that practically all the information concerning OKLO on the NRC website refers to proprietary information[xix] .

Several vendors provided descriptive information on their designs, and these descriptions did help us to understand some of the important design parameters that the vendors have considered and specified. While design information is limited, it is clear that the microreactor designs have the necessary characteristics that can be useful as on-site generators. A summary of the information obtained from these vendors is provided below, and Appendix D has additional details and references of public information.

Summary of Vendor Design Concepts

eVinci Westinghouse Microreactor Design [xx] [xxi]

The eVinci microreactor is designed by Westinghouse for a target application in the next decade to generate heat and electricity for resilient operation in remote communities, as well as commercial and government installations. The reactor is designed to be manufactured and fueled in a factory environment and transported to a proposed site. The design has a scalable power generation ranging from 1 to 5 MWe. The eVinci concept is an evolutionary design based on the Los Alamos National Laboratory *Megapower* reactor concept for space applications. It uses advanced heat pipe technology to transfer the reactor heat to a Brayton power conversion system. The eVinci reactor core is designed to use conventional uranium-oxide fuel (or TRISO fuels) in a solid monolithic reactor core with minimal moving parts for reactor control and shutdown. It is designed to operate for more than three years without refueling and maintenance. The reactor module is also designed to require a minimal number of on-site operational personnel.

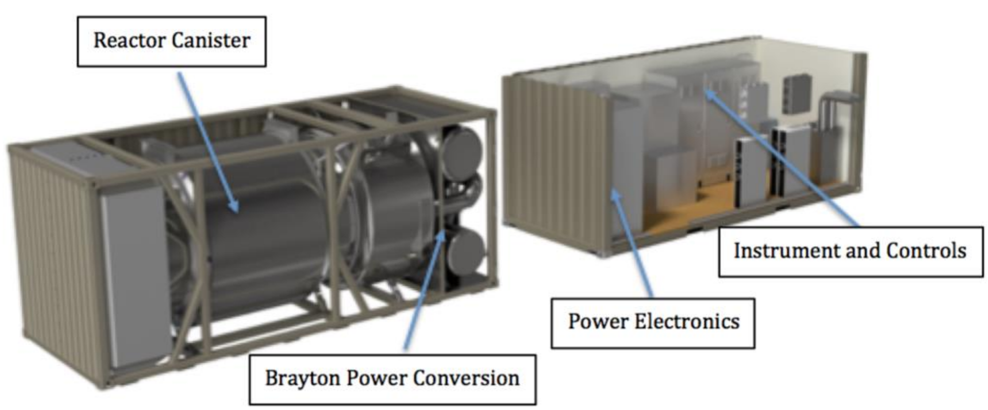

Figure 2.1: Westinghouse eVinci Concept

Holos Quad/Titan Microreactor Design [xxii] [xxiii]

The Holos microreactor designs are targeted for deployment within the next decade. These microreactors are designed to provide heat and electricity in remote locations. These designs are small enough that they could be transported to a proposed site via standard ISO shipping containers by rail, sea, and potentially aircraft. A closed Brayton-cycle is used in these designs, which mimics a turbojet engine. This turbojet engine design builds on the findings of the XNJ-140E reactor project of the 1950's. The Holos Quad design, which is composed of four subcritical modules housed within one ISO container, can generate up to 13 MWe and the Titan concept employs several of these modules together. Each design has redundant control systems as well as mechanical systems, which can change the core geometry rapidly. The reactor core is fueled by >10% enriched TRISO fuel that is embedded in a graphite matrix and are designed to last up to 12 years on one fuel loading. The design has passive decay heat removal as well as most mechanical systems designed to be automatic, thereby limiting the number of required on-site personnel.

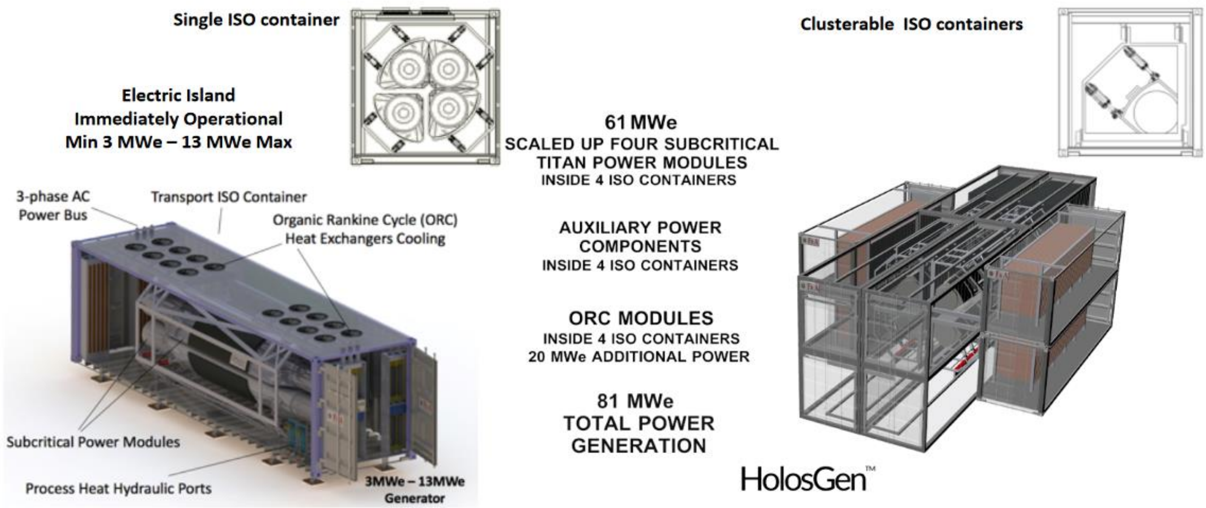

Figure 2.2: HolosGen Reactor Concept

Hydromine Lead-Cooled Fast Reactor (Tl-X) [xxiv]

The Hydromine reactor design is a liquid-metal-cooled fast reactor concept (LFR). The coolant is molten lead. This fast reactor design is part of a small group of concepts that make use of liquid metal coolants in order to take advantage of their superior heat transfer characteristics. The LFR design has two power levels, namely the AS-200 and TL-X, which are 480 and 60 MWth reactors respectively. The TL-X is the modular microreactor design, 15-60 MWth, intended for use in remote locations such as mines, military bases and islands. The design has a design life of 30 years with a refueling cycle of 8 years. Hydromine has proposed this design to be transportable to the site with central facilities for fuel servicing and maintenance. The core is designed to be a "monolithic cylindrical bundle" in a triangular lattice so it can be extracted as a package for replacement of the fuel as required. Hydromine is considering Uranium-oxide as a fuel but advanced fuels (nitride and carbide) are under consideration with

Figure 2.3: Hydromine Reactor Concept

uranium enrichment levels below 20%. System safety is optimized with the reactor not requiring external power sources or human operator intervention for passive shutdown or decay heat removal. More design detail is yet to be disclosed by Hydromine as it is still in the conceptual design stage. The power conversion system was not specified but past LFR concepts have used either Rankine or Brayton power cycles.

NuScale LWR Microreactor Module [xxv]

The NuScale Power Module (NPM) design is targeted for deployment in the next few years as a source of electricity. The NPM is a self-contained module, and the reactor vessel and containment are designed to be shipped to a location and to be installed in an overall facility that can support multiple power modules. Modules are sited below-grade in a pool of water that acts as the ultimate heat sink. The NPM's function similarly to current LWRs, however the module contains both the primary and secondary side of the power cycle. Additionally, an NPM relies on natural circulation for core-cooling and heat transport to the steam generators and the power conversion system. This makes the NPM much more resilient to any accident. The current fuel assembly design for an NPM is a shortened version of the standard 17x17 PWR arrangement, with the fuel enriched to less than 5% ^{235}U (all enrichments are given in weight percent). NuScale envisions offering an advanced reactor type of this design as a micro-NPM, i.e., a single 10-50 MWe power module. This advanced design builds on their current expertise.

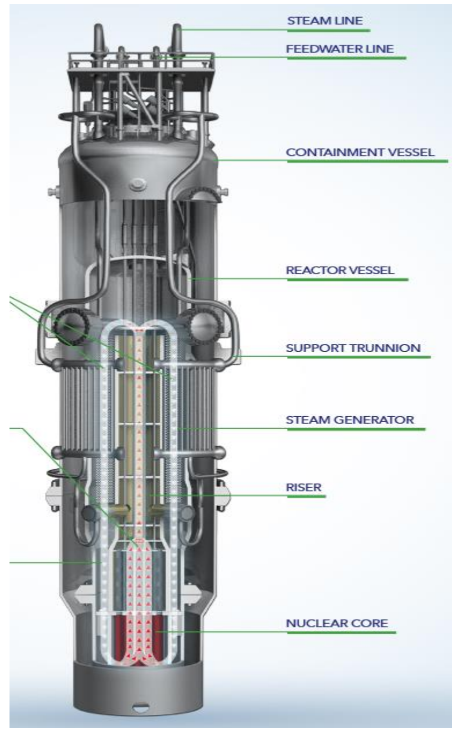

Figure 2.4: NuScale LWR Module

MicroNuclear LLC Micro Scale Nuclear Battery (MsNB) [xxvi]

The MicroNuclear LLC Molten-salt Nuclear Battery (MsNB) is a microreactor conceptual design targeted for deployment as a source of electricity in remote locations. Using a shipping cask confinement, this reactor module would be transported to various locations to deliver up to 10MWe. This molten salt reactor is based on dissolved-fuel molten salt technologies most similar to the Molten-Salt Reactor Experiment performed at Oak Ridge National Laboratory and uses natural circulation for cooling the liquid fuel-salt. Reactor heat is then transferred to a helium Brayton-cycle via a sodium or potassium heat pipe. The MsNB is designed to operate for 10 years without refueling with redundant reactor shutdown systems. Due to the usage of natural circulation within the reactor core, there are no pumps and a minimal number of valves. Limited additional design information was available for public release.

Oklo Aurora Microreactor [xxvii]

Oklo has developed a compact fast spectrum reactor, Aurora. It is designed to serve remote, rural and native communities as well as industrial and military installations. The Aurora reactor produces 4 MWth, which is far smaller than any commercial reactor in the U.S., and smaller even than some research reactors. The reactor core is designed to use metallic uranium fuel enriched to below 20% ^{235}U and to operate for up to ten years without refueling and maintenance. The core thermal energy is transferred to a power conversion system (Brayton Cycle) via sodium heat pipes. The core power level is controlled by external reflectors and shutdown control rods. The smaller thermal power of the Aurora also leads to a much lower decay heat production. The decay heat generated can be dissipated by conduction heat transfer from the reactor module, through the metallic structural materials and shielding, to the surroundings. The reactor module is also designed to require a minimal number of on-site operational personnel for a group of modules. Recently, the Oklo design was submitted for NRC regulatory review.

Figure 2.5: Oklo Aurora reactor concept

Urenco U-Battery Microreactor [xxviii]

URENCO has developed a microreactor design, termed U-Battery, which is a modular design that departs from the standard large-scale nuclear reactors. This reactor design has a scalable design concept with a planned output of 10 to 20 MWth. The design employs a gas-cooled dual circuit design with helium as the primary coolant. URENCO chose an indirect Brayton power cycle with nitrogen as the working fluid for power production. U-Battery makes use of TRISO-fuel as its fuel with less than 20% ^{235}U and is graphite moderated. The expected lifespan of a U-Battery unit is 60 years with a five-year refueling cycle. A thorium fuel-based design has also been considered based on relative cost compared to uranium and related configurations such as a Seed and Blanket fuel block. In developing this design emphasis has been put on modularity, safety and a prolonged fuel cycle term of up to ten years. Rolls-Royce is a likely partner in the reactor design and development.

Figure 2.6: Urenco U-Battery Reactor Concept

Ultra-Safe Nuclear Corp (USNC) Micro-Modular-Reactor [xxix]

The USNC Micro-Modular Reactor (MMR) is a microreactor conceptual design targeted for deployment within the next decade as a source of process heat and electricity in various remote locations. Each module of this design can supply roughly 15 MW of thermal energy through an intermediate molten salt loop. The USNC design employs two reactor modules to be paired with one intermediate heat exchanger, which is coupled to a Brayton power cycle. Each MMR reactor module most closely resembles the GEN-IV High-Temperature Gas Reactor and uses TRISO particles, which are encased in an additional SiC structural matrix, which are then embedded in graphite blocks. The MMR is designed to be transportable in a standard ISO container and designed to operate for 20 years without refueling. A cartridge-based fuel core is employed to streamline refueling. The USNC MMR design is now being considered for demonstration at the Canadian Nuclear Laboratory.

Figure 2.7: USNC Reactor Concept

X-Energy XE-RRM Microreactor Design [xxx]

X-Energy is developing a range of small modular reactor designs that provide power and heat for expected demand in remote communities, government installations as well as commercial applications. The XE-RRM design is a gas-cooled microreactor (HTGR), which is designed to address non-military applications. The reactor system design makes use of a UCO TRISO fueled pebble bed core design, cooled by pressurized helium coupled through a steam generator to a Rankine power conversion system. The TRISO fuel employs high-assay, low-enriched uranium (<20% ^{235}U). The nominal reactor configuration is designed to output 20 MWth of thermal energy and operates at 37% net efficiency to produce 7.4 MWe. Passive decay heat removal systems with redundant shutdown systems are also part of the design. The emphasis of the design is to increase safety, achieve an operation with minimal operator actions and increase

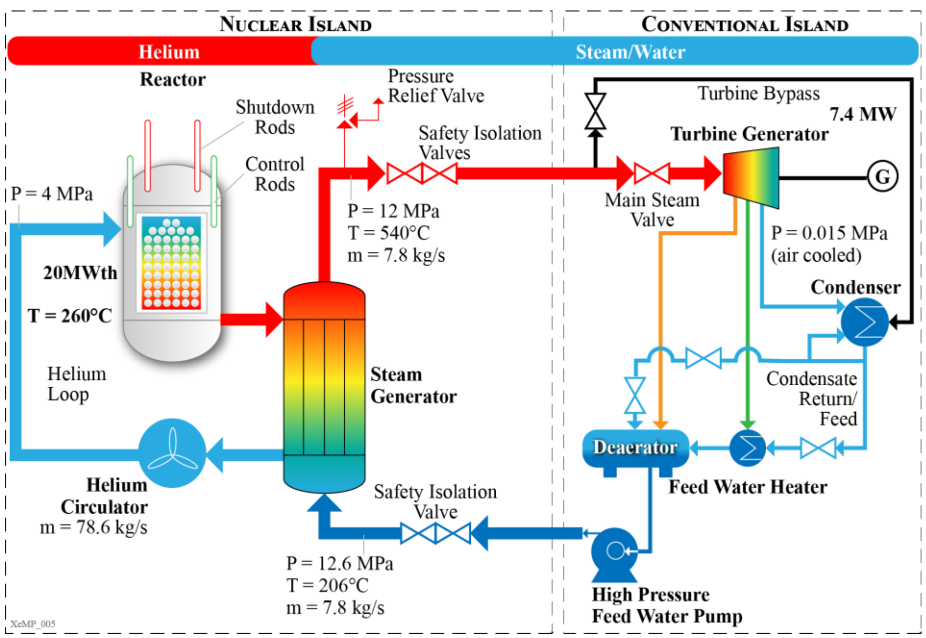

Figure 2.8: X-Energy RRM Concept

the modularity of the components of the reactor system. X-Energy estimated the levelized cost to range from $140-200/MWh for operation of the XE-RRM reactor.

Microreactor Cost Estimates

For the purposes of our work, one of the most significant pieces of information on microreactors is a realistic estimate of the various costs associated with these reactors, i.e., research and development (R&D) costs, First-of-a Kind (FOAK) costs and Nth-of-a-Kind (NOAK) costs. After considering all the other relevant parameters and given the technical readiness for demonstration, these costs will determine whether microreactors will be competitive as on-site generators at federal installations or industrial facilities.

At this time none of the vendors provided details regarding cost estimates. While cost estimates are likely known to developers as proprietary information, public details were not provided. Thus, we base some of our cost estimates on those aggregate values reported in a recent NEI study (NEI, April 2019[xxxi]) as well as other information in the public domain. For example, Table 2.1 below presents the First-of-a-Kind cost estimate ranges from the NEI study, which was based on a compilation from a survey of potential microreactor developers. And among these costs, the most significant is the estimate of the overnight capital cost of a microreactor. This cost estimate will be the starting point for our work in the next section of this report.

Table 2.1: First-of-a-kind from NEI

Cost Component	Units	Nominal	Range
Overnight Capital Cost	$/kW$_e$	$15,000	$10,000 - $20,000
Fixed Operations and Maintenance Cost	$/kW$_e$	$350	$250 - $450
Fuel Cost including used fuel management	$/MWh$_e$	$10	$6 - $14
Cost of Refueling cycle (transport and installation w/o fuel)		$20m	$13 - $27m
Decommissioning Cost	$/MWh$_e$	$5	$3 - $7

Based on the recent experience from advanced LWR development, the capital costs drivers that have the largest potential to reduce cost are design standardization, design completeness, factory construction of major portions of the reactor system as well as standardization for on-site civil structural activities[xxxii]. Given the size of microreactors, standard designs of the complete reactor system would be expected along with factory construction of the reactor modules. Additional attention will need to be focused on minimizing on-site construction as well as employing standardized construction practices. These could involve construction techniques used in factories and shipyards, advanced structural solutions (e.g., steel-plate-concrete composites, high-strength reinforcement steel, high-performance concrete structures), seismic isolation technology or plant layouts that involve below-grade-level structures. Given that microreactors will also have to accommodate external hazards further innovation may be needed.

Regardless of design details, microreactor developers will need to identify the supply chain that will be required to acquire or to manufacture key components for the concept. Because of their small size, these design concepts could benefit from working with current manufacturers that supply similar components for other power systems. Finally, if suppliers are not available, then R&D investments would be required to develop manufacturing technologies for key components, e.g., reactor vessel, core internal structures, heat exchangers, other power conversion system components. In fact, advanced technologies, such as additive manufacturing, may be appropriate and economically competitive for certain key components. Another issue that needs to be addressed is the need for the appropriate Quality Assurance in the manufacturing facility to satisfy requirements, i.e., to translate what is done in the field today into an integrated factory production setting. The experience of the nuclear navy and the expertise of its suppliers would be a good starting point to organize a comprehensive effort. Finally, R&D could also focus on materials research into components that are required to operate in adverse operating environments, i.e., high temperatures, high-pressures and radiation fields.

Another crosscutting activity that needs to be supported is fuels development and related fuel-cycle economics. Most microreactor designs will utilize high-assay low-enrichment uranium fuel and a supply chain still needs to be established for this purpose. These designs are looking toward longer core life, and this will require some systems analyses that investigate what is the appropriate fuel cycle scheme that balances front-end fuel cycle costs (feed, conversion, enrichment, and fabrication costs) with back-end costs of refueling and fuel transport costs. This would be particularly true given that these microreactor systems may be sited in a variety of installations (e.g., federal installations or industrial parks). We expect that most of these designs will utilize proven uranium-oxide fuel technology or the maturing uranium-oxy-carbide TRISO or uranium-metal technologies. Any more advanced fuel technologies (uranium-nitride or uranium-carbide) will require additional fuel testing, development, and qualification.

Chapter 3
Economic Analysis

In order to increase resilience at Government installations, facility managers will first need to increase the efficiency with which they distribute power on their sites. By consolidating generators and providing simplified distribution systems, installations can reduce the down times associated with power failures that originate within the borders of the installation. Thus, the first subject in this chapter concerns microgrids: what they do and what they will cost.

Once a site can manage its on-site power efficiently, a site manager can further increase resilience by looking into different on-site generators, and different ways of using those generators. Over the next 10-20 years, government installations will be replacing their on-site generators and, other things being equal, facilities managers will want to replace their aging generators with technologies that are cost effective (low annual cost). In addition, they will want to use the on-site generators in a configuration that best represents their needs for increased resilience. The second subject in this chapter treats the alternative technologies that can be integrated into the installation for on-site power generation. The third section treats four suggested configurations (scenarios) that will enhance resilience. Finally, we compare the annual cost of these alternative technologies for the four scenarios being considered.

Microgrids

A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. The microgrid can be connected and interconnected to the external larger interconnected electrical grid in such a manner as to provide no interruption to the critical loads and distributed energy resources.[xxxiii]

Currently, an on-grid installation purchases power from a utility. The installation typically has several buildings or facilities that are the end user of that power. In order to increase resilience in case of an outage, the individual facilities on the installation often have on-site generators, typically diesel reciprocating engine generators, associated with each building or facility. Should utility power be lost temporarily, the several on-site generators restore power to each of the associated buildings.

Today there is an increasing emphasis on microgrids, a more efficient way to manage the generation and distribution of power within the boundaries of an installation, along with a means to secure the continued operation of critical facilities should the power from the grid be temporarily unavailable. For a Government installation with several buildings that need power, the micro-grid might comprise on-site generation that would pick up the load during a utility outage, and a distribution system that would get the power to the individual buildings. The micro grid plus the on-site generation would replace or augment the many smaller generators that currently service individual buildings. The microgrid would also include a controller for managing and distributing the load, both from the utility and from the on-site generation. Finally, the microgrid might include a new distribution system (upgraded electrical wires) that would move the power from the controller to the individual buildings where the power is needed. It should be noted that in a number of cases our team studied, the electrical distribution hardware as well as local generation for the installation had already been upgraded to improve local physical grid resilience. As a result of the upgrades or additions, an installation would already arrive at a first, necessary step in increasing its' resilience to a power failure due to a utility outage.

Currently microgrids are becoming more sophisticated as the facility managers demand more services from the microgrid.   A recent paper by NREL[xxxiv] identifies several levels of capability of microgrids along with the estimated cost of installing the microgrid. (Table 3.1).

Table 3.1: Summary Results of NREL Microgrid Cost Study

				Application History			
Level	**IQR [$/MW]**	**Mean [$/MW]**	**Definition**	**Utilitity**	**Campus**	**Commercial /Industrial**	**Military**
Level 1	$2,856,775–$931,485	$1,981,800	Pre-Microgrid Distributed Generator (DG) and Grid Interface Controller				
Level 2	$4,870,648–$2,178,975	$3,462,685	Pre-Microgrid Level 1 + add'l DG + Distribution Automation				
Level 3	$3,820,975–$1,940,507	$3,053,979	Microgrid Level 2 + Microgrid Controller +Thermal Assets + Renewable Energy /Storage				
Level 4	$5,142,510–$3,727,321	$4,436,563	Microgrid Level 3 + Load Management				
	Note : Ref. 2016 NREL Microgrid Case Study Database						

The costs in the table above represent a range of costs, plus an estimate of the mean. Note however that a facility manager would need to consider several component costs in designing a microgrid for a specific facility. In addition, some installations may have already made a substantial investment in distribution systems and distributed energy resources suitable for microgrid application. These resources would then make up a large part of the assumed total costs from Table 3.1. As much as 50% of these costs may be unnecessary depending on the installation chosen for deployment of the microreactor. There are many causes for the large range of costs shown in Table 3.1 above. They take into account factors such as: many levels of functionality that can be specified within the simplified definition of levels 1 through 4; local market conditions and regulatory regimes; purchasing advantages of particular utilities vs other microgrid purchasers; assumed initial on-site grid equipment capable of being converted to microgrid operation; etc.

The NREL study breaks these costs into four general categories:

- Technologies to be managed (diesels, natural gas generators, solar, storage, etc.).
- Controller for the microgrid.
- Infrastructure : distribution, communications, metering, etc.
- Soft costs: engineering construction, regulatory.

Since we cannot specify the actual needs of the many installations that are relevant to this study, we make a conservative estimate of the cost by choosing a high level.   Thus, for the analysis that follows, we assume that:

- Each site will need to install a new microgrid, which will have the capability of providing load management for electric power, thermal power, renewables and energy storage, etc.
- The annual cost of increased resilience will be the cost of the microgrid plus the cost of the technologies assumed to be used for on-site generation.
- The cost of the microgrid for this analysis is assumed to be $4.4 million.

Note: Microgrids need to work smoothly in concert with electricity purchased from the utility. They are also becoming more sophisticated in their ability to satisfy the many demands of a smoothly functioning on-site system of generation and distribution. A more detailed discussion of microgrids is included in Appendix E.

The important point to note in our discussion is that microgrids are an essential first step in increasing the resilience to an outage. A microgrid must be in place if on-site generation is to be effectively distributed across the facility rather than just supplying adjacent buildings.

Technologies

In this study, we analyzed the cost of several technologies that might provide on-site power for a government installation. In each case we have chosen to compare the cost of using any technology based on levelized annual cost for the technology, which includes technology capital cost, operations and maintenance (O&M) cost and fuel costs as appropriate. The technologies have distinctly different attributes, and it helps to define their attributes and associated costs before going any further.

<u>Microreactor</u>: Chapter 2 provides a summary of the design concepts. Because cost estimates for this technology are still uncertain, we considered a wide range of costs in calculating the annual cost of deploying the microreactor. The annual cost of deploying the reactor primarily depends on the initial capital cost and the cost of operating and maintaining the reactor. Appendix F shows the range of costs currently available in the public literature. The appendix also shows our choices, and the references, for the range of costs used in calculating the annual cost of this technology – low, medium and high values.

<u>Diesel generator</u>: Reciprocating diesel engine generators are the most common technology used for providing backup power to a building or facility on a site. While diesels are commercially available, there is still a range of values for the capital cost of this technology, and some variability on the operating (O&M) costs and fuel costs. Again, Appendix F shows references and our choice of values for the cost of using a diesel generator.

<u>Natural Gas generators</u>: An alternative to using diesel fuel in a reciprocating engine is to use natural gas assuming a gas pipeline is available. This is a common approach for smaller power requirements (~1 MWe) but, as the power requirements become significantly larger (>10 MWe) it is more common to use a natural gas turbine generator (open-cycle or closed-cycle). In our cost analysis we make no distinction between these two technologies as the costs have similar cost variations. In the case of natural gas generators, there is reasonable agreement on the range of costs for natural gas-powered generators (Appendix F).

<u>Renewables</u>: We considered two renewable technologies: Solar Photovoltaic (PV) and Wind Turbines. It became a challenge to model renewables as they might be used for on-site power. First, the estimates of the capital cost vary more than traditional energy technologies, depending on the source in the literature. Second and more importantly, both solar and wind are intermittent sources. Their outputs vary by the time of day and time of year. While these variations are often

averaged and explained in terms of a low capacity factor, the situation is more complicated. In order to provide power at a constant level as needed for critical loads, it is necessary to provide energy storage, which is typically in the form of batteries, and the capacity of the renewable generator needs to be sized such that it is able to charge the batteries to a level where the batteries can take over when the renewable resource is not available.

This requirement leads to dramatic results concerning the electrical generation capacity needed as part of a renewable + storage system. Specifically, in northern latitudes or in parts of the country that experience overcast skies most of the time, or where average wind speeds are low, the batteries drain rapidly, and they then need to be recharged rapidly in order to be ready for the next period where the primary source of renewable energy is again unavailable. There are two important and related consequences. First, the batteries must be sized to accommodate the duration of the longest period with inadequate natural resource availability. This leads to large storage installations. Second, if these periods of inadequate natural resource availability are frequent, the generator (solar or wind) needs to be sized to recharge the batteries quickly enough to be prepared for the next period during what may be a short interval when sunlight or wind is available. Thus, the capacity of the solar generator is dictated by the duration of time necessary to recharge the batteries, and this is much different, and much greater, than the capacity that would be needed to simply provide a constant power to a fixed load.

Scenarios

We calculated the annual cost of using the above technologies for four different scenarios – corresponding to four different levels of resilience.

Based on the data gathered in Chapter 1, we chose to model a "surrogate" installation. This site is characterized by an average demand of 4 MWe and corresponds to the minimum demand for the 211 government installations where a reactor might be an appropriate on-site generator. For our analyses we assume that the critical load at such a site is half that amount, 2 MWe, which led us to consider on-site generation sized at 2 MWe. Nevertheless, consistent with our previous conclusions about resilience, in order to avoid a potential failure of the on-site technology, there are cases where the on-site generator should be backed up by a second generator. That backup generation would also be sized at 2 MWe and would be of a different technology.

The scenarios, in order of increased resilience, are:

1. <u>Status quo</u>: In this scenario, the utility provides the primary source of power, supplying 4 MWe. Backup capacity is designed for the critical load of 2 MWe, to be kept in stand-by and run only if needed in an emergency. This is the current approach, used by utilities, to achieve resilience.

2. <u>Critical power level supplied on-site</u>. Utility provides 2 MWe. On-site power supplies 2 MWe. Our assumption is that if the on-site generation goes down, the site would buy more power from the utility. Correspondingly, if the utility goes down, the on-site generation would continue to meet critical power needs, uninterrupted. Enhanced resilience, compared to scenario 1 is achieved because on-site generators are assumed to be able to operate indefinitely during a utility outage, and is backed by utility power during an outage of the on-site generation.

3. <u>Critical power supplied on-site, with additional backup for the on-site generators.</u> As in scenario 2, the utility provides 2 MWe. On-site generation supplies 2 MWe. But in this case,

we assume that we can back up the primary on-site generator with another diverse set of on-site backup generators. This costs more but provides additional resilience. It covers the case when both the utility and the on-site power generators might go down at the same time.

4. All power supplied on-site, with no power supplied by the utility. This essentially takes the installation off-grid and assumes supplying power is completely under the control of the installation. This scenario provides for a set of on-site generators to provide all power (4 MWe). It includes a set of backup generators sized at 2 MWe to provide critical power, should the primary on-site generators go down. It should be noted that the peak and average load are assumed to be the same. This assumption underestimates the cost of all systems and underestimates the cost of capital-intensive technologies (nuclear and renewables) more than fossil systems.

One last point on resilience that applies to all the above scenarios. A single load of reactor fuel will allow the reactor to operate for many years; current designs up to 12 years. On the other hand, the quantity of fuel available for a diesel generator is limited by local conditions, including weather. Thus, because of confidence in the fuel supply, a reactor has an inherent advantage for resilience over a diesel. As for gas, as long as the pipeline is operating, the availability of fuel is the same as for a reactor. Nevertheless, in our Scenario 3 we note that we cannot depend on gas from a utility for a backup, and that LNG would be needed as a backup fuel. In this case also, a reactor has a resilience advantage over LNG since the reactor provides more confidence in the fuel supply.

In order to determine the annual cost associated with using each of the technologies, we needed to consider the cost of financing each technology. Since the financing cost is often negotiated for each purchase, it was not possible to come up with an interest rate that applied to all of the technologies. The financing cost is further complicated by the fact that different technologies have different lifetimes. Thus, a microreactor could last from 20-60 years, while a diesel generator operating continuously may have an expected life of 5-10 years (Appendix F). Given that we did not have a fixed interest rate to use for the calculations, we assumed that the interest rate would range between 2% (a low value that might represent government financing of a project) [xxxv] and 10% (a high value that might represent commercial financing of a project).

In all these scenarios, the "system" parameters are assumed to be the same: Utility costs ($.06/kWh), duration of the assumed outage (7 days, per DOD guidance), etc. See Appendix F for system assumptions. Results, for all the inputs and scenarios, and assumptions about financing, are shown below.

Sizing of Renewable Energy Systems

In order to determine the necessary size of the various components of a renewable energy system, including solar PV and/or wind, with necessary battery storage, and accounting for variability in the solar and wind resource, we made use of a commercially available software package called HOMER Pro®[xxxvi], originally developed by the National Renewable Energy Laboratory (NREL). In this application, HOMER optimizes the capacity needed in the solar or wind generator, with the size of the batteries, in order to provide the required power output. For our analysis of the surrogate site, consistent with our discussion in Chapter 1, we chose a range of 2 to 4 MWe.

We modeled the weather by averaging solar irradiance, temperatures and wind speeds over several years to determine the variations as a function of time of year for a particular location, in this case for our surrogate site we chose Madison, Wisconsin.

The HOMER analysis produced dramatic results. For solar, the necessary capacity of the generator is determined by some periods of the year when demand is high and the solar and wind resource is low. In order to provide a constant 4 MWe, the HOMER model predicts that the required installed capacity of using only a solar PV array would need to be 133 MWe, which would then both provide energy directly and additional energy to keep the batteries charged. Further, once the batteries are charged, the system continues to generate electricity in excess of the amount needed to satisfy the demand of 4 MWe. In fact, the solar generator would generate excess energy of 138 GWh each year. A similar situation occurs for a wind generator.

In the process of analyzing the cost of the renewables, we also found that a combination of Solar and Wind would be less expensive than either technology by itself. We pursued that approach, again using the HOMER software to optimize the Solar+Wind+Battery resource and determined the cost for this combination. This combination results in capacities that are substantially lower, but still large. Assuming 2% financing, in order to generate 4 MWe, the capacity of the solar generator would need to be 35 MWe, and the capacity of the wind generator would need to be 18 MWe.

Table 3.2 below shows the relevant numbers for each of the cases that we analyzed, for a system that would generate a constant 4 MWe.

Table 3.2: Summary of HOMER results for Solar, Wind, or Solar+Wind

In order to produce 4 MWe	**Solar**	**Wind**	**Solar + Wind**	
			Solar	Wind
Generator capacity (MWe)	133	75	32	19
Battery capacity (MWh)	273	330	1140	
Excess energy (annual) (GWh)	138	129	60.7	

Appendix G shows how the results vary as a function of the location and weather. Specifically, we compare the required capacities of both the solar and wind generators for two cities in the US: Madison, WI, and Phoenix, AZ

Scenario 1. (Status quo)

In Scenario 1, the backup generators are kept in standby, to be used to supply the critical load during a utility outage. The diesel and gas generators are assumed to be "off" except that they run for 7 days per year, resulting in a minimal use of fuel. The microreactor is assumed to be kept in warm stand-by during the year, and run at full power for 7 days, just like the diesel and the gas generators.

For this scenario, we needed to change our assumptions concerning the lifetimes of the gas and diesel generators. The lifetime of these generators is commonly measured in terms of the time that the generators are running, rather than their actual age. Because these generators are running so little, we assumed that the lifetime of the diesels and gas generator would be the same as the lifetime of the microreactor.

The renewable technologies do not apply to this scenario, although the batteries do apply. It will always be less expensive to charge the batteries using power from the utility rather than buying additional equipment (solar and wind generators) for the purpose of charging the batteries.

Batteries are assumed to be sized such that they can provide 2 MW for 7 days, during a winter in Madison, Wisconsin.

Figure 3.1 below shows the results of the calculations for Scenario 1. The graph on the left shows that the choice of batteries to provide backup power is not economic. Compared to the other technologies, it would cost at least three times as much to provide backup power using batteries for this period. The graph on the right shows that the lowest cost options for backup are diesels and gas generators, that the capital cost for each is similar, and that the fuel cost is so low that there is only a slight difference between the two. The graph on the right also shows that a microreactor can possibly compete with a gas turbine or a diesel generator, but only under two conditions. First, the cost of financing needs to be low, probably around 2%. Second, the cost of the reactor needs to be at its lowest cost values.

As shown in Appendix F, in order for the reactor to compete with gas or diesel, the capital cost of the reactor would need to be about $4,000/kWe, O&M costs at about $100/kWe, and fuel costs at 12 $/MWh. In this and the scenarios that follow, the reactor competes successfully only if its cost is at the lowest values used in the model. From this point on, we refer to this as the "target" cost for the microreactor. Nevertheless, since the capital cost of the microreactor dominates the overall annual cost, it does not make sense to employ this technology for short operational times as considered here.

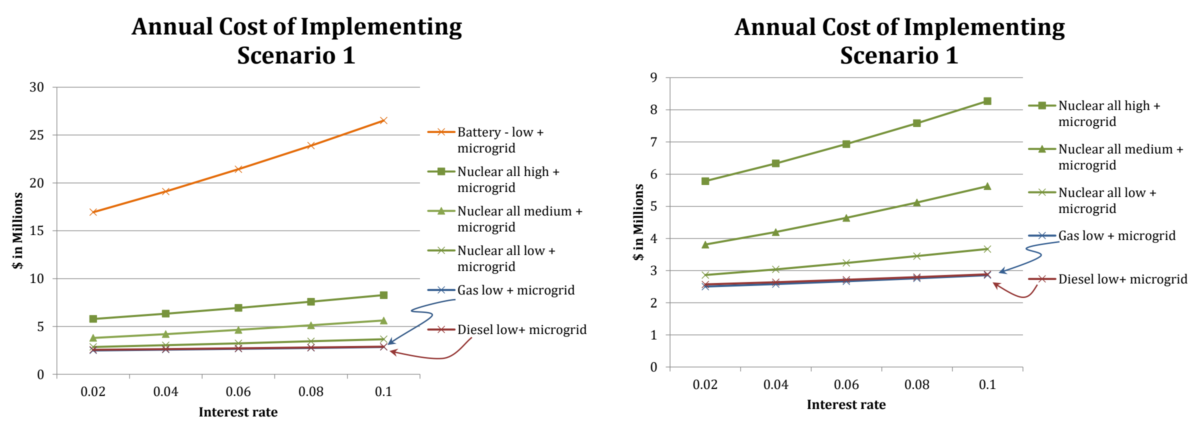

Figure 3.1: Base Case - Status Quo

Scenario 2 (Critical power level supplied on-site)

In scenario 2, the on-site generation runs constantly at the critical power load (2 MWe), while the utility provides the remaining power (assumed constant at 2 MWe). If the utility goes down, the site is provided with 2 MWe from its on-site generators. Conversely, if the on-site generation goes down, the utility can serve as a backup and increases its output and the site receives its required 4 MWe.

The inputs for the analysis are taken from Appendix F, which shows high, medium, and low values for each of the required inputs needed to characterize the candidate backup technologies. Initial calculations showed that the high and medium values for renewables would be very costly and we chose not to display the results for these calculations. Figure 3.2 below displays the cost for only the low cases for solar, wind, and solar+wind. That analysis, on the left in Figure 3.2, shows that even these cases are more expensive than either diesels, natural gas, or a microreactor.

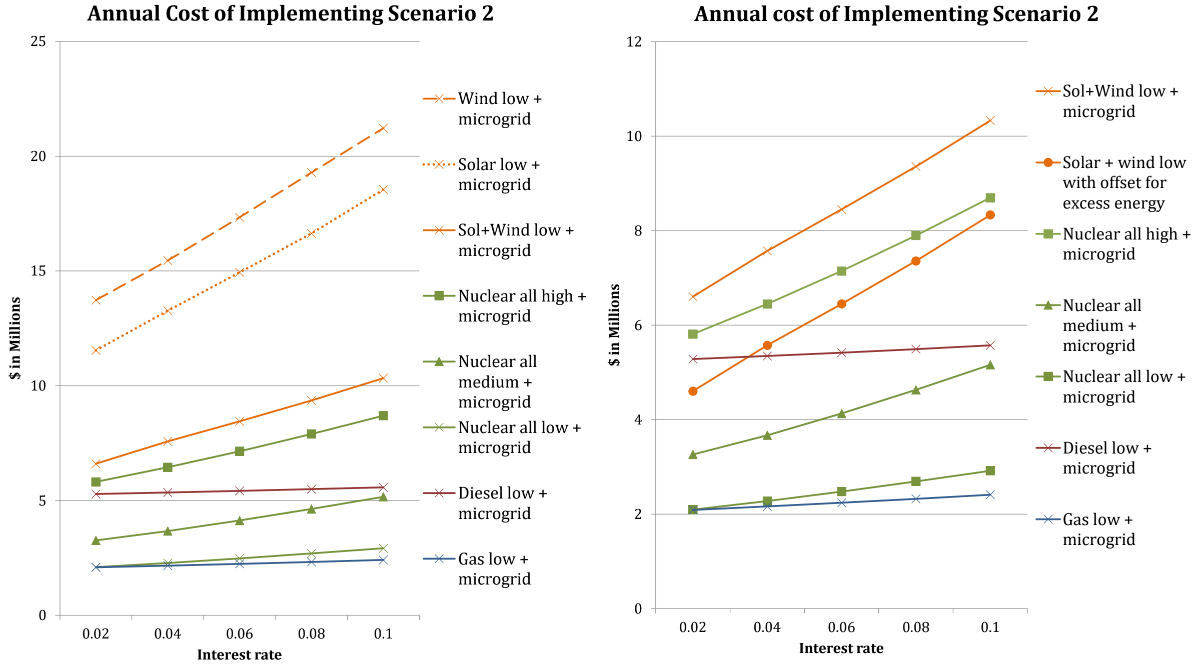

Figure 3.2: Annual Levelized Costs for Scenario 2 – Critical Power Supplied On-Site

For the renewables in Scenario 2, we also encountered the issue of the excess energy, which we discussed in the section on renewables. As shown in Figure 3.2 the lowest cost renewable technology is a combination of solar and wind. This combination keeps the system running, but at the same time it produces an additional 31.5 GWh (See Appendix G) of energy beyond the 35 GWh needed to keep the surrogate installation running. Because the site is connected to the grid, we assume that, for the renewables case, the extra energy would be used on site; the generator would produce more than just the amount of energy to meet the site's critical demand. If utility power costs $60/MWh, the site could avoid the need to purchase 31.5 GWh/Y and would save $1.9 million per year. The graph on the right in Figure 3.2, we show this "credit" or "offset" explicitly.

The results of the calculations for Scenario 2 are shown in the right graph in Figure 3.2. Natural gas is still the least expensive option and could be implemented for about $2 million per year, and the annual cost is driven by fuel cost and is essentially independent of the interest rate, making gas generators the likely choice of technology should an installation choose this approach for resilience. The microreactor is only cost competitive when the low target costs are considered and the financing cost approaches 2%.

Note also that the cost of this choice is less than the corresponding use of natural gas in Scenario 1. The implication is that Scenario 2 results in a higher level of resilience, and yet saves money every year given the assumed utility cost for electricity.

The analysis also shows that the lowest cost using diesels would lie about half-way between the high and low estimates for the microreactor. If the cost of the reactor ends up near its mid-range values, and if the financing charges are above about 4%, then diesels could compete with the reactor. Finally, if the ultimate cost of the reactor is at the high levels shown in Appendix F, and if the combination of solar+wind can profit from the value of the excess energy produced, it is possible that this combination, solar+wind, can compete with a microreactor.

Scenario 3 (Critical power level supplied on-site – with on-site backup for the on-site generators.)

In scenario 3, the on-site generation runs constantly at the critical power load (2 MWe), while the utility provides the remaining power (constant 2 MWe). If the utility goes down, the site receives 2 MWe from its first line of on-site generators and can sustain its critical load. If the primary on-site generation goes down simultaneous to the utility outage, backup on-site generation picks up the critical load.

Consistent with our assumption that resilience not only implies redundancy but also diversity, the emergency backup generators are of a different technology from the main on-site generators. Thus, a microreactor, renewables or a natural gas generator would use a standby diesel generator for backup, while a diesel generator would have a natural gas generator in standby.

The enhanced resilience comes about because of the combination of main on-site generation, plus emergency backup for the on-site generator. With this configuration, the site can continue to provide for the critical load at the site in the case when the utility might go down at the same time as the primary on-site generation.

As with scenario 1, the backup generators are assumed to run only 7 days per year. Thus, as in scenario 1, we assume lifetimes for the backup generators are the same as for the microreactor. In addition, we assume that a utility outage could include an outage of either an electric utility or a gas utility. To account for this possibility, the fuel for the gas generator that generates the critical power would be natural gas supplied by a gas utility. For the standby gas generator, the fuel is assumed to be LNG. The cost of LNG and its storage facility is also given in Appendix F. Note also that, given the previous analysis that shows that batteries are very expensive, we did not consider a case in which batteries would be used to back up any of the other technologies.

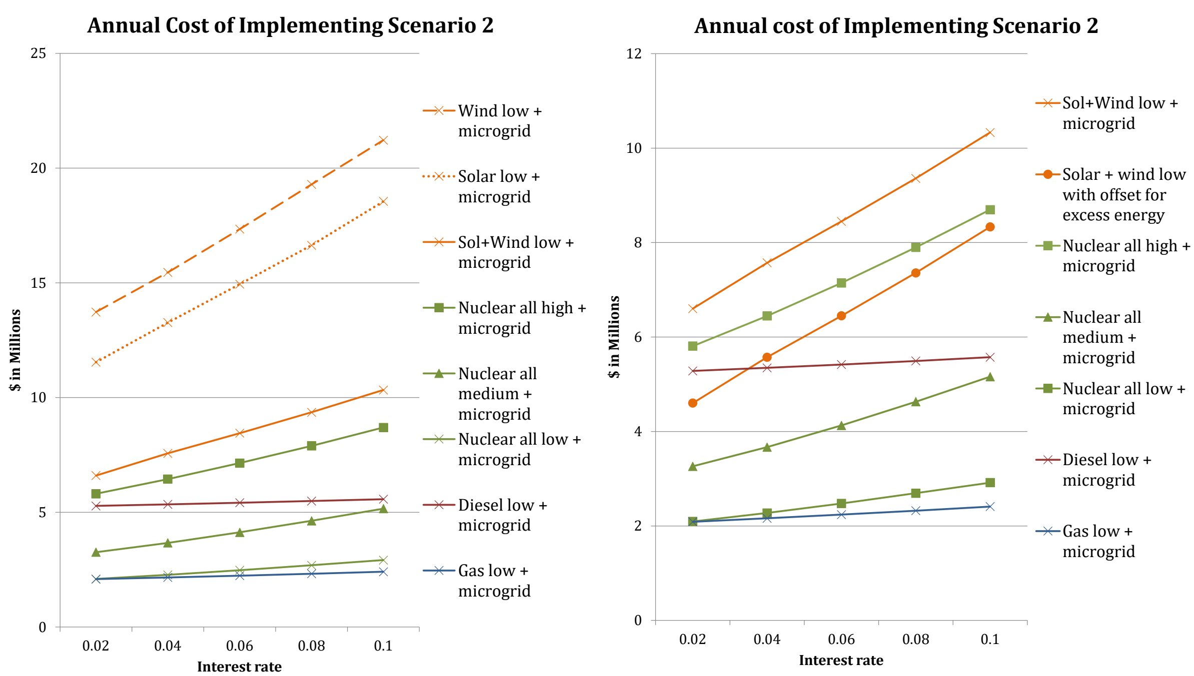

Figure 3.3: Annual Levelized Costs for Scenario 3
Critical power level supplied on-site – with on-site backup for the on-site generators.

Figure 3.3 shows the results of the model for Scenario 3. As expected, costs are slightly higher than in Scenario 2 because each of the primary on-site generators now has its own diverse backup. As with the previous scenarios, the renewables are not competitive with diesels, natural gas or a microreactor, even if the microreactor ends up at the highest cost assumed in Appendix F.

As with Scenario 2, the graph on the right shows that a diesel generator at its lowest cost value would cost as much as the higher estimates of the microreactor. This is primarily due to the high cost and high usage of diesel fuel. We also find the interesting case that by using the excess energy on site, the combination of Solar and Wind can be competitive with the microreactor, should the microreactor end up costing close to the high value assumed in Appendix F. If, on the other hand, the cost of the microreactor achieves close to the target costs along with lower interest rates, the microreactor can be competitive with gas.

Scenario 4 (All power supplied on site.)

Scenario 4 takes the installation off-grid, supplying power in a way that is completely under the control of the site manager. This requires the on-site generation to provide all the needed power (4 MWe). It adds in a set of second line (emergency) backup generators, sized at 2 MWe, to provide critical power should the primary on-site generators go down. Consistent with the scenario that the installation is disconnected from the utility, we assume that:

- Fossil fuels must be provided for storage on-site, i.e., diesel or LNG.
- There would be no gas pipeline available, and LNG would fuel the natural gas generators.
- There would be nowhere to sell any excess energy, so there would be no credit associated with the value of any excess energy.

Figure 3.4 shows that, as with the previous scenarios, the renewable plus storage options are more expensive. For this scenario, the cost of diesel fuel makes a diesel generator uneconomic. Again, we find that a microreactor can be the least expensive option for providing on-site power when compared to either a diesel generator or natural gas generator fueled by LNG, if the cost of the microreactor can be at its target values, and if the interest rate is less than 8%. Again, for this scenario (as with scenario 1 above) we do not consider batteries as a practical backup for any of the technologies. The analysis above shows that batteries are simply too expensive.

The previous analyses compare different technologies within each scenario, assuming that all technologies are providing the same degree of resilience. However, the different scenarios represent different levels of resilience. While all analyses here have assumed an outage of 7 days, one way to assess the relative resilience is to consider the costs of accommodating longer outages. Given the assumption in defining the scenarios, this would only have an impact on Scenario 1 with diesel backup generators because of the need to store more fuel on site. (Scenario 1 with natural gas would also be impacted if its fuel was stored LNG, but the results shown above assume natural gas delivered by a pipeline.) By contrast, the on-site generation in Scenarios 2 & 3, regardless of the technology, is designed to operate continuously whether or not there is a utility outage and is therefore insensitive to the duration of the outage. Appendix H develops a rigorous model for comparing Scenario 2 with a nuclear reactor to Scenario 1 with a fossil generator and stored fuel, with the simplified result that the annual benefit of Scenario 2 is just the cost of purchasing and storing the fuel modified by the probability of an outage. Such a benefit could partially offset the additional capital cost of deploying a reactor.

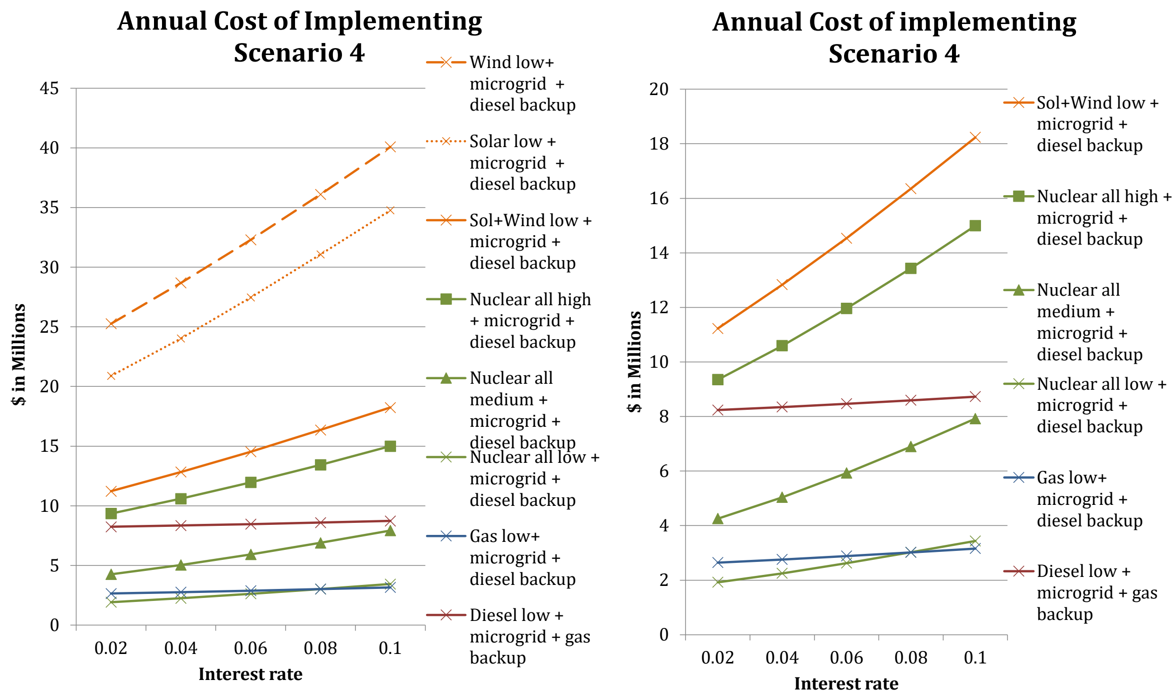

Figure 3.4: Annual Levelized Costs for Scenario 4 – All Power Supplied On-Site

Observations from the Economic Analysis

1. The first observation is that, for scenarios 2, 3 and 4, the annual cost of the least expensive option is about the same for each of the scenarios, about $2 million. For this surrogate site, the analysis indicates that it is possible to achieve higher levels of resilience without a significant increase in the cost.

2. Scenarios 2, 3 and 4 are less expensive than the status quo as analyzed in Scenario 1. This result is an artifact of the assumed utility power cost.

3. In scenario 1, where the generators are kept in standby, diesel generators are competitive with gas generators. In all the other scenarios, where the generators are run continuously, diesels suffer from high fuel costs and diesels are no longer competitive with either natural gas or reactors, again assuming that a microreactor can achieve the target cost used in this analysis.

4. In all the scenarios treated in this analysis, a microreactor can be less costly than on-site diesel generators and can compete with a natural gas generator only if all the assumed cost of the reactor can approach the target values considered in this report.

5. To be explicit, if a microreactor is to compete with gas <u>in any of the scenarios</u>, the parameters associated with the reactor need to be at, or more favorable than the "best" values used in the model. In order to meet these targets, a focused R&D effort needs to be initiated prior to any large-scale deployment of a microreactor.

Table 3.3: Best case economic parameters necessary for microreactors to compete with natural gas.

Parameter	Target level	Units
Capital Cost ($/kWe)	4,000	$/kWe
Capacity Factor	.98	
Plant life	60	Years
Fixed O&M cost	100	$/kWe
Fuel cost	12	$/MWh
Decommissioning	3	$/MWh

6. Depending on the scenario, the choice of technology for on-site generation is dependent on the cost of financing. The range of interest rates varies from around 2%, which could imply government financing and possibly government ownership, up to around 10%, possibly a reasonable value for private financing. Thus, besides the necessity of the reactor achieving its target values, the competitiveness of a reactor will depend on favorable financing, which could imply government ownership. Conversely, the annual cost of running a natural gas generator rises only slowly if the site needs to finance its installation at a higher cost of capital.

7. These analyses have implications for the potential use of microreactors in the private sector: potentially at remote locations where utility power may not be available, or where utility bills are extremely high. Specifically, for an isolated site with no access to utility power, scenario 4 provides guidance on the cost of generating all the installation's electricity on-site.

Chapter 4
Carbon-Free On-Site Power Generation (Green Site) Scenario

In the previous chapter, we considered a surrogate site that required 4MWe of electrical power (both average and peak power) and we compared several alternative technologies for enhancing resilience by providing on-site generators. At each step, resilience was increased by using larger amounts of on-site power. The last scenario showed the economics of taking a site off-grid and using only on-site power.

In this chapter we explore another alternative for taking a site off-grid. Specifically, we analyzed a case in which the site used only on-site power, and, in addition, power derived from carbon-free generators - hence the label "Green Site".

Initially, we used the HOMER microgrid design and optimization software to derive the cost of powering a site with solar and/or wind with battery storage. In the process of that analysis, we discovered that a combination of solar+wind+batteries would be less expensive than either solar alone or wind alone by about a factor of two (see Figure 3.4).

That analysis led us to ask the next logical question: Are there cases where it might be yet cheaper to integrate a microreactor into the mix of carbon-free power generators? Conversely, might it be more cost effective for a microreactor to be combined with battery storage and renewable technologies? In order to explore this possibility, we adapted the HOMER software to find an optimized mix of a reactor+renewables+batteries that would be less expensive than simply using either renewables or a reactor. By exploring various cases for the "mix" we discovered that there may indeed be situations where a combination of a reactor+renewables+batteries may provide a lower overall cost to provide power for an off-grid site.

The appropriate situations arise because most sites will face the same problems that a utility has in following load. A typical site will have an average demand but will experience periods of minimum and maximum (peak) demand. In such cases, the power delivered to the site will have to follow the load as it changes, possibly in short span of time (on the order of minutes). A utility typically follows a changing load with two types of generators. A base load generator provides a constant level of power or slowly varying level of power. It provides low-cost power, but it is does not follow a rapidly changing demand. The utility then employs so-called "peaking plants", generally natural gas fired generators, which can provide additional energy quickly, adding the necessary power above the constant power level provided by the base load plant, and can satisfy peak demand.

If one wished to power a site with carbon–free on-site generators, the same situation could apply. A set of microreactors could provide the base load, with renewable resources and battery storage, providing the electricity above the base level.

Analysis Approach

In order to explore the possibilities for such a combination of technologies, we analyzed a series of cases to meet the site load requirements using only microreactors, renewables and battery storage. At one extreme, the reactors might be run continuously at the chosen design capacity providing base load, and renewables and batteries could provide additional power as needed, up to the level of peak demand, for as long as necessary. Alternatively, the reactors might also follow the load within specified design limits, but likely with different overall design capacity integrated with renewables and batteries. The reactors would have load following constraints (e.g., 5% per minute), and the renewables and batteries would supply the additional peak power necessary to meet overall demand subject to their own constraints (i.e., variable solar flux and/or wind speed for a site).

To provide an example for analyzing this possible situation, we created a surrogate site with characteristics that could demonstrate the usefulness of an optimization of these carbon-free technologies. We assumed a site with an average demand of 4 MWe (similar to our surrogate site analyses), but we imposed more realistic power demands throughout the year. Specifically, we considered power requirements from a minimum of 2.6 MWe to a peak demand of 6.3 MWe with the load profile patterned from the UW-Madison campus. As noted elsewhere in this report, the required amount of solar and wind depends strongly on the site location and its associated weather pattern. We also used the weather pattern in Madison, WI, essentially putting this new surrogate site in the northern Midwest. This realism adds to the complexity of the integrated design since weather patterns (solar flux and/or wind speed) can also change quickly (on the order of minutes).

The first challenge in pursuing an optimum mix of carbon-free power is that the HOMER software does not have a 'built-in' model for a nuclear reactor electrical generator. Thus, as part of this work, we developed a nuclear electrical generator model using the HOMER generic electrical generator input model. That microreactor generator model is described in detail in Appendix I. Also, a variety of cost and performance information is required to build an electrical generator model in HOMER, with additional inputs required to properly represent a microreactor within the HOMER analysis. The details for HOMER microreactor generator used in these analyses are also presented in Appendix I.

To explore the integrated carbon-free generator system potential to minimize costs, we developed a stepwise cost-optimizing dispatch strategy using HOMER, coupled to the dispatch module using MATLAB. The dispatch strategy dictates the order in which each generator is called upon to meet the power requirement over a given time span. The dispatch strategy is summarized below.

For each time increment, we required the system to choose one out of three dispatch options based on minimizing the cost of the mix of technologies. In this analysis, the cost and performance parameters of the reactor and the renewable sources are specified as inputs. Because the marginal cost of the renewables (either solar or wind), as well as the batteries, is small in comparison, the dispatch order was constrained to choose the renewable technology to be the first power generator that is dispatched. Any excess renewable energy is used to charge the batteries. Option 1 dispatches energy stored in the battery after accounting for power from solar PV, and then dispatches the reactor if there is still remaining power demand. Option 2 dispatches the reactor to follow the net load (full load minus the PV solar power output) and discharges the battery if the reactor alone cannot meet the net power demand. If the net load is less than the minimum allowable out of the reactor, the excess electricity charges the battery. Option 3 also dispatches the reactor before the battery and requires the reactor power to be ramped up to a level that not only meets the net required load, but also charges the battery to save its energy for future demand. After choosing the option with lowest cost in a time increment, the system then advances in time going through the whole year to generate a site-specific hybrid dispatch strategy with an optimal mix of technologies.

When calculating the marginal cost for each time increment, we include the value of the energy stored in the battery. Note that the battery is primarily charged using electricity from the reactor, so the cost of the energy stored in the battery is the same as the cost of energy generated by the reactor. On the other hand, the value of the energy stored in the battery depends on when that electricity is used. If that energy is released at a time of high demand, it could be worth as much as the cost of building the next increment of renewable energy. To explore the importance of the value of the stored energy, we simulated several cases, valuing the stored energy from $3/MWh up to $180/MWh. The result is that the value of the stored energy does not have a major impact on the dispatch strategy.

At this point we demonstrated that, if we have specified the input parameters: the size of the reactor, the amount of renewable energy available, and the size of the battery – and have included cost and performance data for each of these elements - then HOMER can determine the dispatch strategy, the order in which each of the technologies are deployed, such that the additional energy into the system is accomplished at a minimized cost.

Next, depending on the cost of the various technologies, we need to optimize the system, i.e., derive the sizes of the various technologies that will result in the minimum cost of the electricity produced. We derived the mix of technologies that result in the lowest cost by using HOMER to calculate several cases, where each case assumed different cost and performance parameters for the technologies. We first did a base case (Case 1) where no microreactor is allowed as a point of comparison. Then, we allowed the microreactor input parameters to vary from "Best" target cost and performance values to "Worst", i.e., highest cost and performance values. Finally, we held the microreactor input parameters at "Medium" values and varied the solar PV and battery input parameters from "Best" to "Worst".

Table 4.1 below summarizes the results for the cases considered. For each case, the nuclear costs and he PV-Battery costs, are inputs. The results for the optimum technology combination and their associated annual levelized cost (and cost of electricity) are shown in italics.

Table 4.1: HOMER Simulations
(Surrogate Site: Peak Load – 6.3 MWe, Avg. Load – 4 MWe, Madison weather)

	Inputs		Outputs				
Case No.	Nuclear Costs	PV-Battery Costs	Nuclear Size (MWe)	PV Solar Size (MWe)	Battery Size (kWh)	Annual Level. Cost [A] ($ Mill/yr)	Levelized Cost of Electricity ($/MWh)
1	No nuclear	Best	0	122	220,000	17.8	510
2	Best [B]	Best	6.0	0	0	1.73	49
3	Medium [B]	Best	5.0	10.92	235	4.56	130
4	Medium [C]	Best	5.5	14.45	94	4.11	117
5	Medium [B]	Medium	5.5	0.83	7	4.83	138
6	Medium [B]	Worst	5.5	0.46	9	4.81	137
7	Worst [B]	Best	5.0	14.46	94	9.30	266

Note A: Annual Levelized cost of generation at 2% interest without Microgrid or Backup Costs included
Note B: Capital Cost Method for Nuclear Fuel Model – This is explained in Appendix I.
Note C: Continuous Feed Model for Nuclear Fuel Model – This is explained in Appendix I.

Results

Case 1 is the Renewables-only case. With no nuclear reactor, even with the best performance assumed for the renewables, this case results in the highest cost of electricity produced.

Case 2 allows for a microreactor at its best input parameters to be considered in combination with renewables (Solar PV) and battery storage at their best input parameters. Case 2 results in a conclusion that – if the microreactor can achieve its target costs ($4,000/kWe) - the least cost option would be to build only a microreactor at 6 MWe. There would be no need for renewable generators (either solar or wind), or battery storage. Indeed, comparing the derived cost of cases 1 and 2, the reactor-only case would produce electricity at only about 8% of the cost of the renewables-only case.

In Cases 3, 4, 5, and 6, demonstrate that the optimized "mix" depends on the eventual cost of the microreactor relative to the cost of the renewable generators. If the cost of the reactor rises to its medium value ($12,000/kWe) we find that a combination of a smaller microreactor (5.5 MWe) is chosen along with larger amounts of renewables (Solar PV) to produce the lowest overall cost for the system.

Finally, case 7 shows that the worst case for the reactor ($20,000/kWe) results in further decreasing the size of the reactor (to 5.0 MWe) and requiring that the renewables to carry more of the load. This case also results in the highest cost electricity resulting from the mix.

Conclusions

This analysis has important implications as the Administration looks forward to major initiatives regarding Climate change. Should the Administration wish to consider establishing carbon-free generators at Federal sites:

- It will be necessary to characterize sites by both their average power consumption and their peak power consumption. Each site is different. The size of the peak consumption dictates the amount of peaking power that would be needed to be supplied by renewable sources.
- In order to moderate the cost of a green site, it would be essential to develop microreactors to the point where they could achieve the target costs assumed in this study. As shown in Case 2, (given our assumed site with average power of 4 MWe and peak power of 6 MWe), a reactor would have the potential to power the site with energy costing 4.9 cents/kWh. If the cost of the reactor were to be higher, renewables could help supply peaking power, but the cost of electricity would be about a factor of three higher. Without a reactor, renewables alone could indeed power the site, but at a cost of 51 cents/kWe.

Chapter 5
Case studies

In Chapter 3, we considered a surrogate site with annual average power needs of 4 MWe. Using the model developed by UW, we derived the cost of implementing four increasing levels of resilience. In Chapter 4, we applied that analysis to a Green Site. In this chapter, we apply the analysis to "real" sites. They are:

A. UW Campus, a state institution,
B. Johnson Space Center (JSC), a NASA lab,

Data sheets on each of these sites are found in Appendix J. In each case, the information necessary to perform the analysis is as follows:

Table 5.1: Installation Energy Data Used for Economic Analysis

	Units	UW	JSC
Average Electricity Consumed	MWe	52	18
Peak Electric Power	MWe	82	24
Critical Electric Power	MWe	23	3.8
Average Thermal Power	MWth	116	20
Peak Thermal Power	MWth	245	25
Grid-connected			
Electricity Charge	$/MWhe	60	50

University of Wisconsin – Madison Campus

Obviously UW is not a Federal installation. Nevertheless, compared to other sites considered in this study, the UW Team has access to a much greater level of detail for this site. Given that we have such details, the UW site provides an opportunity to explain how a complex site works. Further details of the UW site are shown in Appendix J.

The site contains 388 buildings[xxxvii] spread over 1.46 square miles. In addition to its need for electricity, the demand for power at UW is dominated by the need for thermal energy and, because of its northern location, the demand for heat varies greatly by season and by time of day.

Table 5.2 below shows the several components of energy use on the site:

Table 5.2: Campus-wide Energy Summary for UW-Madison

	Units	UW
Average Thermal Power	MWth	116
Peak Thermal Power	MWth	245
Average Electricity Consumed	MWe	52
Peak Electric Power	MWe	82
Average Utility Purchased Power	MWe	50
Average On-site Electricity Generation	MWe	2
Electricity Charge	$/MWhe	60
Backup Electricity Generation Capacity (gas & diesel)	MWe	36
Critical Load	MWe	23-36

Future plans for the UW include 23 MWe of on-site power installation. The existing individual building back-up diesel/natural gas generators have a total capacity of 36 MWe. In speaking with UW energy site manager and facility officials, the critical load lies in the range 23-36 MWe. For our subsequent analysis, we use 23 MWe as the critical load input for our analysis.

UW manages its variable load by purchasing electric power, by generating heat and electricity on-site, and by employing backup emergency generators associated with individual buildings. The on-site generators are:

- Charter Street Heating Plant (CSHP), owned by UW,
- West Campus Cogeneration Facility (WCCF), jointly owned by MGE and UW,
- Walnut Street Heating Plant (WSHP). Owned by UW, and
- 108 small generators to service individual buildings for Back-up power (36 MWe)

These plants are employed in such a way as to allow the site manager to balance the variable loads for both heat and electricity. A schematic of the power generation system is shown below.

The cogeneration facilities are used to balance the loads. At times when the demand for heat is high, the cogeneration plants produce electricity as a byproduct; the site then uses that electricity to offset the demand for power from the utility. As an example of the need for such on-site electricity, in 2018 the site produced only 2 MWe (4% of total demand) on site.

The UW campus has an existing, rudimentary microgrid in the sense that there are on-site generators that deliver power to each of the building on the campus. Nevertheless, the 108 small generators are associated with individual buildings and are not part of the microgrid.

For the present, the configuration of generators is adequate to satisfy the variable demand experienced at UW. For the future the site expects to upgrade or increase its number of buildings, which will increase the demand.

Resilience: The site manager suggests that increased purchases from the utility will be adequate to cover expected growth on the campus. In order to increase resilience, the site manager suggests that it would be appropriate to build about 23 MWe of on-site power on the campus, rather than planning to purchase the entire amount of extra power from the utility.

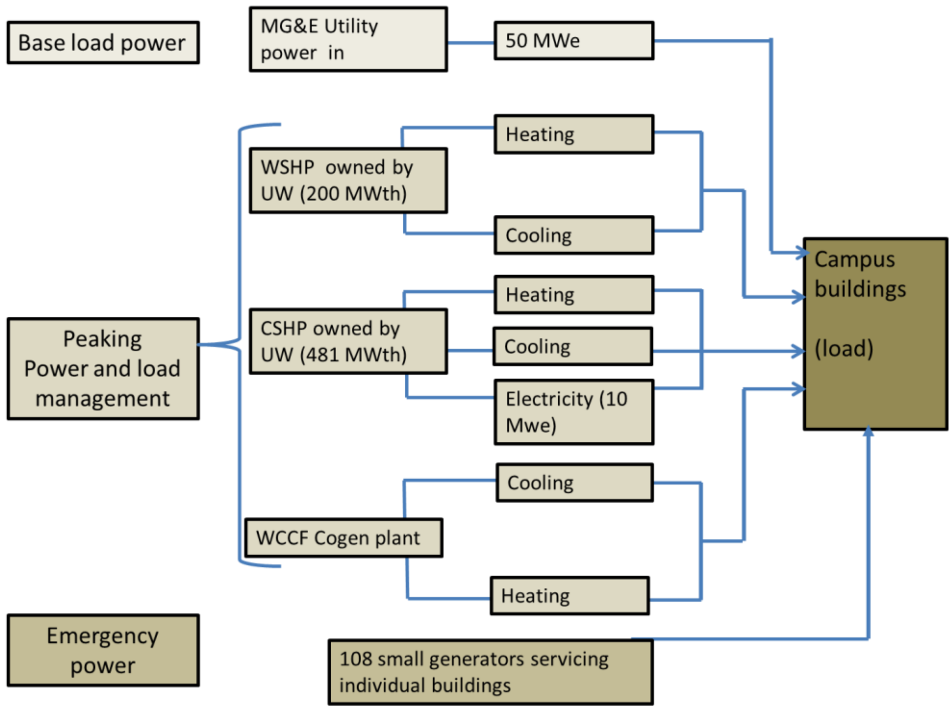

Figure 5.1: Schematic of University of Wisconsin-Madison's combined heat and power system

Analysis

We analyzed two cases for adding 23 MWe to the on-site generating capacity for the UW campus. In both cases, the additional generator(s) would be running full-time, offsetting electricity purchases from the utility. As with the surrogate site in Chapter 3, we considered five technologies to provide the new capacity: a microreactor, diesels, gas generators, solar, and wind with battery energy storage.

In the first case we analyzed, the new generator would have no on-site backup. If the on-site generation were to go down for a time, the site would increase its purchase of electric power from the utility. If power from the utility is disrupted, the current backup generators would be able to provide 36 MWe. This, along with the new 23 MWe would provide the campus with a total of 59 MWe during the time when utility power is not available. This situation corresponds to Scenario 2, which we discussed for the surrogate site in Chapter 3.

In the second case, the new primary on-site generation would have backup generators, as described in Scenario 3 for the surrogate site in Chapter 3. A microreactor, the renewable technologies, or a natural gas generator, would use a standby diesel generator for backup, while a diesel generator would have a natural gas generator in standby. This configuration provides an additional layer of resilience. If both the primary on-site generation and utility power were to be unavailable, the backup generators would provide the 23 MWe. As in Scenario 3, we assume that these backup generators would run about 7 days per year.

Figure 5.2 (for Scenario 2) shows the costs for the case in which the primary on-site generation has no on-site backup. The graph on the left shows that, as with other cases analyzed for this report, the renewables – either solar, or wind, or a combination of the two – are more expensive than the other candidates for on-site power. The graph on the right provides a better view of the costs of the other candidates. Gas provides the lowest cost power and, because gas is cheap, the cost of this option is relatively insensitive to the cost of financing. Diesels, because of their high fuel cost are not competitive with gas. Because of the current uncertainty in cost, the microreactor is shown as a range. If the reactor has costs around the target cost used in this study, and if cost of financing is down around 2% to 4%, then the reactor can be competitive with gas.

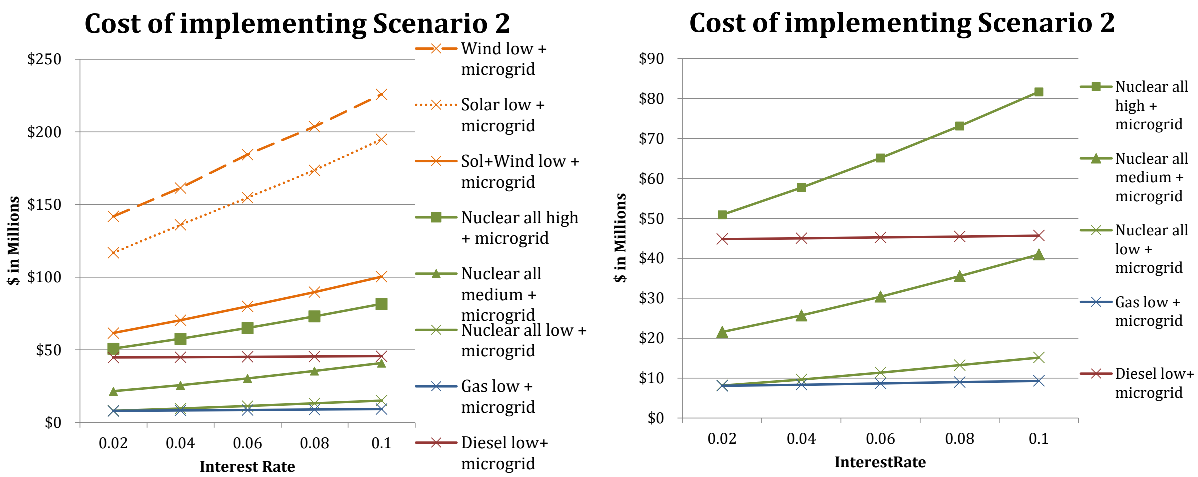

Figure 5.2: Annual Levelized Costs for Scenario 2 at UW-Madison Site.

Figure 5.3 (for scenario 3) shows the costs for the case in which each of the primary on-site generators come with their own backup generators as described above. The relative cost of the technologies is about the same but, with the addition of the costs for the backup generators, this case is slightly more expensive.

The relative costs of the different technological options are the same as in the case above. Gas remains the least cost alternative and is relatively insensitive to the cost of financing the new capacity.

If a reactor can achieve the target cost assumed in this study, and if the cost of financing is down around 2% to 4%, then a reactor can compete with gas.

The problem with the analysis is that, to date, the cost of the microreactor is relatively unknown. If UW makes its decision to purchase new generating capacity in the next 10 years, it would probably be safest to invest in natural gas fired generators. If UW waits beyond 10 years, there will be time to complete the necessary R&D and demonstrate the technology and the cost of the microreactor will be more certain.

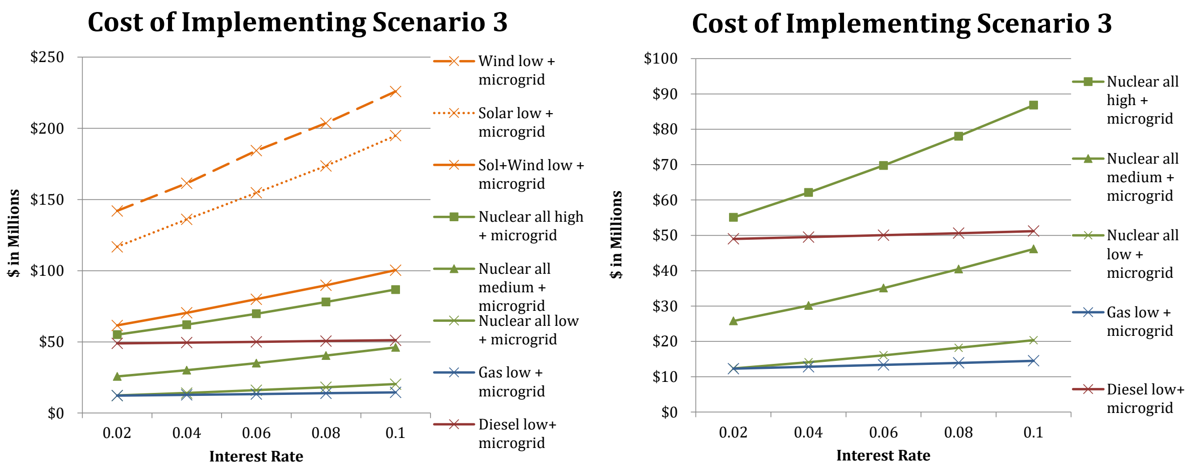

Figure 5.3: Annual Levelized Costs for Scenario 3 at UW-Madison Site.

Johnson Space Center (JSC)

Johnson Space Center (JSC) consists of a complex of 100 buildings constructed on 2.5 Square miles (1,620 acres) in the Clear Lake Area of Houston. There are approximately 3,330 civilian employees at the facility, 105 buildings, 2 major substations, and 5 sectional sub-stations.

This NASA facility underwent an energy upgrade in 2011, with the construction of an on-site combined heat and power (CHP) plant. (See Appendix J).

Table 5.3 below shows the several components of energy use on the site:

Table 5.3: Site-wide Energy Summary for Johnson Space Center

	Units	JSC
Average Thermal Power	MWth	20
Peak Thermal Power	MWth	25
Average Electricity Consumed	MWe	18
Peak Electric Power	MWe	24
Average Utility Purchased Power	MWe	6
Average On-site Electricity Generation	MWe	12
Electricity Charge	$/MWhe	40-70
Backup Electricity Generation Capacity (gas & diesel)	MWe	3.75
Critical Load	MWe	3.8

The on-site CHP, fueled by natural gas, generates 12 MW continually, offsetting the need for power from the utility. To provide resilience, the CHP is backed up by diesels capable of generating an additional 3.75 MWe.

JSC is satisfied with its current electric power configuration. With a critical load of 3.8 MWe, and power available from on-site generation of 12 MWe from the CHP, plus the availability of an additional 3.75 MWe from the diesels, the site has adequate resilience, should power from the utility become unavailable.

For the future, JSC plans an expansion to meet its mission requirements, with an attendant need to increase its power requirements. For the future, JSC foresees that its critical load will likely increase to about 7.6 MWe. Even at that level, the on-site power of 15.75 MWe (12 MWe + 3.75 MWe) will be adequate to cover the increased critical load.

Relative to the analysis in Chapter 3, the current situation at JSC can be described as robust. The resilience is currently at a higher level than that described in Scenario 2, and nearly adequate for the situation described in Scenario 3.

In our scenario 2, we assumed a level of resilience that would be achieved by having on-site power equal to the critical power demand of the site. According to JSC, over the next 10-20 years, that critical demand will be about 7.6 MWe, while total on-site generating capacity will remain at 15.75 MWe. If utility power is not available, on-site power could still satisfy the critical load. If the CHP goes down, purchases from the utility could be increased to satisfy the total power needs on the site.

In our scenario 3, we described a level of resilience that would move yet further from reliance on the utility. In this scenario, the primary on-site generation is backed up by other generators that would be used for an emergency, should the primary on-site generation be unavailable for any reason. For JSC the on-site generation produces12 MWe of continuous on-site power, backed up by diesel generators with a capacity of 3.75 MWe. For the future, JSC anticipates a critical power requirement of 7.6 MWe. If both utility power and the CHP were to be unavailable, the site would still have a critical demand of 7.6 MWe, but would only be able to generate 3.75 MWe. In order to satisfy the criteria in scenario 3, JSC might consider the purchase of another 4 MWe to adequately cover its anticipated critical load of 7.6 MWe.

In our Scenario 4, independence from the grid, the site would need to be able to satisfy its peak demand (24 MWe) using only on-site power. Given the current on-site generating capacity of 12 MWe, JSC might consider the possibility of installing an additional 12 MWe.

One note on resilience, as it would apply to the case where JSC might decide to go off-grid. In our analysis of a small surrogate site in Chapter 3, we assumed that the primary on-site generators would need to be backed up with a second tier of generators to deal with the possibility that the principle on-site power generator might experience an outage. For a large site like JSC, recognizing that diversity is an important part of resilience, the on-site capacity would logically be supplied by several smaller generators, using at least two different technologies. If one of the on-site electric generators were to become unavailable, the other generators in the group could still provide enough power to satisfy critical demand. Thus, unlike the case for a very small site, a large site like JSC would not need additional backup generators; multiple generators would provide the on-site capacity and, as a group, they could provide the necessary power to compensate, should one of them go down for a period.

Below, we derive an estimate of the costs that would be involved should JSC decide to increase its resilience to the level described in Scenarios 3, and 4.

For scenario 3, the issue is the cost of an extra 4 MWe capacity to ensure a supply adequate to satisfy the critical load. For Scenario 4, the issue is the cost of an extra 12 MWe to ensure that the site could satisfy its peak load.

Analysis

The graph on the left in Figure 5.4 shows the results of the analysis for scenario 3, the incremental costs that JSC might expect in order to have an extra 4 MWe online continuously. The renewable combination, an optimized mix of solar and wind (with batteries) is the highest cost option, about two to three times more expensive than either the fossil or nuclear alternatives. The cost of a microreactor is shown as a band, with a range that depends on the ultimate cost of the microreactor. Because of the high cost of diesel fuel, diesel cannot compete with gas and it is unlikely that diesel engines could compete with a microreactor. For a gas fired generator, we used an estimate of the cost of LNG, as shown in Appendix F.

The result of the analysis is that, if a microreactor can achieve its target cost, and if the cost of financing is around 2%, a microreactor could compete with electricity from a gas generator. The incremental annual cost of either option would be about $1.4 million. On the other hand, the annual cost of using a gas generator is relatively independent of the cost of financing. Thus, if financing costs are above 2%, a gas generator would probably be the preferred option.

Scenario 4 describes the case in which the site goes off-grid and new on-site capacity supplies 12 MWe. In this case, the optimized combination of renewables is again not competitive with gas. Nevertheless, if the cost of a microreactor is at a high level (See Appendix F for input parameters) the solar/wind combination could be less expensive than a microreactor. Diesels because of their high fuel cost are also not competitive with gas. The analysis also shows that, if the cost of a microreactor is at its target level, and if financing costs are favorable, a microreactor should be able to compete with electricity from a gas generator. Specifically, electricity from a microreactor could cost an additional $3.6m per year, while gas could cost an additional $4.9m per year.

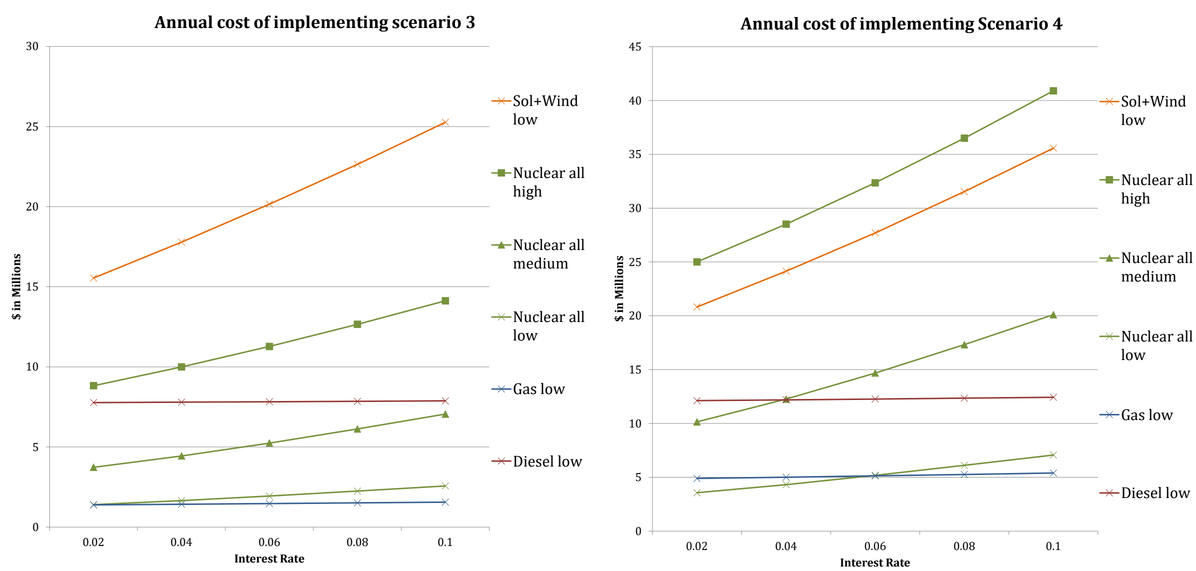

Figure 5.4: Annual Levelized Costs for Scenarios 3 & 4 at JSC.

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Chapter 6
Regulatory Issues

Since microreactors are to be demonstrated for eventual commercial use, reactor licensing by the Nuclear Regulatory Commission (NRC) is the recommended path. The NRC has different pathways to license reactors. Under current NRC regulations, there are two licensing approaches that the applicant can use:

- A two-step license process (10CFR-Part 50), which involves a Construction Permit (CP) followed by an Operating License (OL).
- A one-step license process (10CFR-Part 52), which involves a Combined Operating License (COL).
- A new approach (10CRF-Part 53) is under development by the NRC for completion by mid-2020's.

In order to gain the necessary operating experience to validate key design features, we expect that the first microreactors will be demonstrated at a DOE site as full-scale prototypes. A full-size prototype reactor could be the most direct and expeditious way to demonstrate the overall reactor performance for normal operation as well as testing during transients. NRC is currently working to resolve key policy issues associated with microreactors, e.g., siting, staffing, security and required accident analyses. We foresee that the most significant issue will be the ability to site microreactors near population centers with key insights developed from licensing research reactor facilities.

Current regulations for nuclear power plant commercial licenses issued under the Atomic Energy Act [xxxviii] (Section 103) have focused on ensuring the safety of large light-water reactors (LWRs). Microreactors will likely use non-LWR fuels, non-aqueous coolants and could be operated in innovative ways that imply load following, black-start, transportability, automated control systems, and minimal staffing. These attributes will need to be specifically addressed as new or unique, since the Nuclear Regulatory Commission (NRC) has not routinely dealt with such designs for a commercial license.

In this report, we consider possible licensing pathways for microreactors and then identify key regulatory issues that must be considered in any licensing framework. Finally, we recommend a potential path forward to address such issues.

Licensing Pathways

In this study, we consider that a microreactor will be sited and operated in the continental U.S. The reactor may be owned and operated by a governmental agency (e.g., DOE or DOD) or owned by a private entity and operated for the government. The reactor may also be operated for commercial purposes (i.e., electricity revenues) and deliver power to a federal installation as part of the overall mission. The Atomic Energy Act provides various possible options for licensing a nuclear reactor as a utilization facility in the U.S.

Non-commercial pathway: If the reactor is under U.S. government ownership (or its private contractor) and not for commercial use then there are two license pathways:

[1] If the reactor is under DOD ownership (or its private contractor), then one could use the 91b provision of the Atomic Energy Act for military application of a utilization facility. This assumes the military could license the facility and may seek NRC technical assistance as part of the regulatory review. This was the approach taken by the U.S. Navy for its land-based reactor prototypes and is the approach now planned for the DOD Pele program for a mobile microreactor.[xxxix]

[2] If the reactor is under DOE ownership (or its private contractor and/or operated on DOE controlled site) and is not used as for eventual demonstration for commercial purposes[xl], one could use the DOE regulations and directives to license the facility. DOE can also seek NRC technical assistance as part of the regulatory review. This was the approach taken by the DOE for the Advanced Test Reactor and is also being pursued for the Versatile Test Reactor[xli].

Commercial pathway: If the reactor is for eventual commercial use, then one is required to seek an NRC license regardless of the nuclear reactor ownership, e.g., Section 103, 10 CFR Parts 50, and Part 52 (or Part 53 now under development). It has been suggested that a demonstration microreactor could be licensed as research reactor under Section 104. However, this requires a different license for the demonstration reactor and then again for the commercial offering. Such an approach is a possible path but would take longer. In either case, licensing by the Nuclear Regulatory Commission (NRC) is the recommended pathway.

NRC Licensing Approaches

In current NRC regulations, there are two licensing approaches that the applicant can use:

- 10 CFR Part 50 two-step license: Construction Permit (CP)/Operating License (OL)
- 10 CFR Part 52 one-step license: Combined Operating License (COL).

In the 10 CFR Part 50 licensing approach [xlii] the owner-operator submits a preliminary safety analysis that provides initial details on the reactor design, siting and operation requesting a construction permit for the facility. As construction nears completion, then the owner-operator submits a final safety analysis report for the operating license of the reactor. The CP/OL licensing approach has been used for the licensing of all commercial nuclear reactors constructed and operated in the U.S. to date[xliii]. It has recently been used for licensing of medical radioisotope production facilities.

In the Part 52 license approach[xliv] the owner-operator submits a complete reactor design for construction and operation in a single step with optional separate pre-approvals for the reactor design. When the reactor receives a COL and successfully completes all required inspection after construction, operation of the plant is granted without an additional mandatory hearing[xlv]. Applicants are more likely to seek a COL after obtaining a Design Certification (DC) for the reactor design or a Standard Design Approval (SDA) for a major portion of the reactor design. In a DC or SDA, applicants seek approval for the generic design of a reactor facility or major portion thereof, independent of the site where it will be operated. The application for a DC or SDA should contain the same level of technical design information present in an OL or COL application but considers facility operation for a generic site operational envelope. The AP1000 LWR at the Vogtle site has used the Part 52 process.

In 2019, Congress passed the Nuclear Energy Innovation and Modernization Act (NEIMA)[xlvi]. This new legislation directs the NRC to develop a new licensing approach by 2027 with a regulatory structure for advanced reactors, which includes microreactors. This new licensing approach will be a separate approach, so-called Part 53. In response to this Congressional action, the NRC staff has already developed a risk-informed, performance-based licensing process; so-called Licensing Modernization Project (LMP)[xlvii]. The NRC staff has also noted that this LMP licensing process may also be used within the licensing approach for either Part 51 or Part 52. This licensing process has now been released for public comment as Regulatory Guide 1.233[xlviii], "Guidance for a Technology-Inclusive, Risk-Informed, and Performance-Based Methodology to Inform the Licensing Basis and Content of Applications for Licenses, Certifications, and Approvals for Non-Light Water Reactors".

The microreactors would likely be constructed in a factory as a nearly complete module, shipped to a specific site and be installed with minimal on-site construction. Given that characteristic for all of these designs, using Part 53 may be preferable, but until completed using either Part 50 or Part 52 would be doable. It may be more practical and expeditious to license the demonstration reactor under Part 50 as the design evolves and the reactor is tested as a demonstration reactor during startup and power ascension. On the other hand, it is also possible that the COL licensing approach under Part 52 could be utilized with a manufacturing SDA pre-approval for the microreactor design. In addition, the LMP approach can be used as an optional process for either of these approaches. This is the approach chosen for the Oklo microreactor[xlix].

Microreactor Regulatory Issues

The design characteristics and safety features of microreactors are expected to be quite different from those of current commercial LWRs. The key feature of microreactors is that any single reactor module has a much smaller inventory of fission products, approximately proportional to its thermal power. Microreactors would have radioactive inventories similar to current research reactors, like the NIST research reactor[l]. While microreactor modules are similar in this aspect to research reactors there are important differences. Microreactors will be required to normally operate at full power with a power conversion system instead of engaged in tests and experiments. Thus, there would be less need for human actions for operation and more automatic features involved in reactor operations.

As microreactor designs are refined from conceptual in nature to complete engineering designs there are potential policy issues that need to be addressed. These include:

- Staffing requirements for operations/monitoring on-site vs. remotely,
- External man-made hazards to the facility (e.g., aircraft impact),
- Physical security requirements at the facility.

These topics as well as others have been identified by industry [li] and are now under consideration by the NRC staff. It should be noted that most of these issues are not unique to microreactors, but rather had been identified as issues when small modular reactors were first considered over a decade ago [lii] in discussions between the industry and the NRC. As a practical matter, the NuScale Design Certification application has helped clarify such issues and should allow the NRC to develop workable policies.

Microreactors are also expected to have a variety of design features and safety systems. However, regardless of the microreactor design, these conceptual designs do have a set of common safety enhancements that are being incorporated into these design concepts, resulting in a much lower risk profile. There will be safety systems with passive features, e.g., natural circulation used for long-term decay heat removal. In addition, designs incorporate material combinations with properties that have inherent safety characteristics, e.g., fuels with enhanced fission product retention and smaller accident source term. Microreactor designs will also aim to minimize operator actions needed for safe operation and control. One should consider these unique safety features in order to demonstrate that accident frequencies are lower and that the consequences of accidents are acceptable and meet the regulatory requirements. For example, beyond-design-basis accident scenarios (severe accidents) are used in evaluation of reactor siting and emergency planning.

Microreactor Siting

To identify these accident scenarios, one needs to apply risk-informed principles, rather than strict prescriptive application of deterministic criteria. These accident scenarios can be used to define the maximum credible accident that determines the associated source term for the facility. This process is important since the accident source term (radioactive material that could be released to the environment) is needed to form the basis for siting [liii] near population centers as well as for emergency planning[liv].

With the development of small modular reactors as well as microreactors, the NRC has recognized that the specific source term and siting practices used for large LWRs may not be appropriate for the licensing and regulation of advanced reactor designs. Factors such as smaller source terms, passive safety systems, and advances in fuel and containment barrier technologies would allow for siting of a facility closer to densely populated centers than has historically been accepted for large LWRs.

For example, the NRC has proposed that, while maintaining the siting criteria regulations, the population density guidance should be modified. Using current regulatory guidance would be overly conservative. The current regulatory guidance in Regulatory Guide 4.7 [lv] raises two issues hindering the possible deployment of advanced reactors. The first issue involves the current limitations on population density to not exceed 500 persons per square mile (ppsm) out to a distance of 20 miles from a reactor site. This provision could preclude many sites associated with government installations or industrial sites with relatively large population centers closer than 20 miles. The second issue involves the potential use of these advanced reactors for remote communities or smaller grids with relatively small but concentrated populations that would be near a reactor site.

The proposed changes for use by advanced reactors would maintain the current siting criteria regulations, but modify the regulatory guidance for allowable population densities to:

> *"The population density (500 ppsm) would be assessed out to a distance equal to twice the distance at which a hypothetical individual could receive a calculated dose of 1 rem over a period of 1 month from the release of radionuclides resulting from accidents".*

This revised guidance has risk-informed attributes. First, the dose (1 rem) and time (1 month) are consistent with the required approach outlined in the Licensing Modernization Project for characterization of the dose from postulated accidents for proposed advanced reactor designs. Further, the prescribed distance of twice the 1-rem dose boundary is consistent with the distance required for relocation of local populations to satisfy current EPA protection action guidelines in the event of a severe accident.

Microreactor Prototype Demonstration

Licensing microreactor designs can be challenging if there is insufficient operating experience with critical design features to validate the design or its performance. In the absence of operating experience, key design features can only be validated via separate effects testing, integral testing of certain reactor systems or via demonstration as a prototype reactor. While many separate effects tests can be performed in laboratories without nuclear fuel, integral testing may require use of a full size or a reduced scale nuclear reactor. The validation of critical safety features for innovative designs without significant operating experience will thus likely need to be demonstrated by the performance of a prototype reactor. A prototype reactor [lvi] would test unique design features and is similar to a demonstration first-of-a-kind plant in all features and size but may include unique safety features for added protection during its testing period.

Given the small size of microreactor designs, a full-size prototype reactor could be the most direct and expeditious way to verify the overall reactor performance for normal operation and selected transient testing. This approach for demonstration of new reactor technologies via prototype reactors was recognized and incorporated into the 2019 Nuclear Energy Innovation and Capabilities Act (NEICA)[lvii]. In NEICA, DOE was authorized to provide for the integral testing and demonstration of reactor concepts to be proposed and funded, in whole or in part, by the private sector. These demonstrations are to be accomplished at a DOE national laboratory site and to be done in cooperation with the NRC, since these demonstration reactors are expected to eventually obtain an NRC commercial license. The National Reactor Innovation Center[lviii] established at Idaho National Laboratory is to coordinate such demonstration projects.

NRC Review Process

In the recent past under Part 52, issuance of design certifications (DC) and combined licenses (COL) for large light water reactors has shown that the licensing process can be lengthy and expensive, even if the COL application references a DC for the reactor. The COL process has taken years and at a substantial cost ($30 million). The experience with DC applications for LWRs has been similar. The review time has taken many years and associated costs of the NRC review of DC applications have ranged from four to ten years, and between $50 million to almost $100 million[lix].

More recently, the NRC committed to completing a DC in a 42-month time frame for two specific reactor designs: the Korean APR1400, a large Generation-III+ PWR, and the NuScale small modular reactor, an integral PWR with several novel design features. The APR1400 DC was completed as planned and the NuScale DC final Safety Evaluation Report was issued in August 2020, which meets the planned timeline. However, the cost for these reviews is still substantial (~$50million). Such timelines and costs should not be expected for these microreactor designs.

The characteristics of microreactors should incorporate passive safety features and have inherent design features that can demonstrate that the frequency of severe accidents is remote and that the accident source term and potential consequences of such accidents would not have an adverse impact on the health and safety of the public outside of the facility. For microreactors to meet these conditions, it is expected that safety analyses may not need to include many accident scenarios that challenge current LWRs (e.g., loss of offsite power). Also, many of the safety systems common to current LWRs will not be necessary. Coupled with the expected size and simplicity of microreactors, designs may only include a small fraction of structures and systems and initiating events.

The goal for microreactor safety review and licensing could be patterned after the recent experience with NRC licensing of non-power production and utilization facilities (so-called NPUF). Similar to microreactor designs, these facilities have small radioactive material inventories, the frequency of any accident scenario is expected to be low, and the consequences are also expected to be small outside of the facility boundaries. The revised NPUF licensing rule[lx] was designed to improve the review process for such facilities. Similarly, two recent completed NRC reviews for Part 50 construction permits (CP) for medical isotope production facilities[lxi] (SHINE and Northwest

Medical Isotopes) were completed in a much shorter time period (2-3 years) and a small fraction of the cost for LWRs (about 10%).

The industry has suggested actions that can be considered to make microreactor review more efficient and effective[lxii]. The staff is expected to respond to the industry with its proposed actions during 2021.

Current Observations

Since microreactors are to be demonstrated for eventual commercial use, reactor licensing by the Nuclear Regulatory Commission (NRC) is the recommended path. In order to gain the necessary operating experience to validate key design features, we expect that the first microreactors will be demonstrated at a DOE site as full-scale prototypes. A full-size prototype reactor could be the most direct and expeditious way to demonstrate the overall reactor performance for normal operation as well as testing during transients. NRC is currently working to resolve key licensing policy issues associated with microreactors, e.g., siting, staffing, security and required analyses including external hazards. We foresee that the most significant issue will be the ability to site microreactors near population centers with key insights developed from licensing research reactor facilities.

Chapter 7

Decision to Proceed and Acquisition Options for Micro-Scale Nuclear Reactors.

Given the information and analysis provided in the previous chapters, we concluded that:

- More than 200 Government installations may be capable of siting a microreactor for on-site power.
- The analysis indicates that several scenarios have similar costs, so, it may be possible to achieve increased levels of resilience without increasing cost. Further, with the most favorable cost and performance parameters for nuclear and gas generators, all the scenarios imply a cost that is lower than the cost of the status quo.
- Under favorable conditions (i.e., a microreactor can achieve the target costs as used in the analyses), Scenarios 2 and 4 predict that increased resilience might cost less than Scenario 1, the current status quo, where on-site generators are kept in stand-by.

We also believe that the commercial availability of microreactors for government installations will be based on a number of factors including these three relevant to this work.

- Perceptions of the benefits of enhanced resilience and appreciation that increased resilience can be achieved at similar cost to the current status quo of fossil fueled backup generators.
- Whether adequate funding (either through private sources or Government sources) can be provided for the investments needed so that microreactor technologies can be made available at the target cost. Funding is needed to provide for:
    - The cost of the research and development (R&D) necessary to have confidence that a FOAK demonstration plant can be built with technologies that result in acceptable costs.
    - The cost of a FOAK demonstration plant.

And ultimately,

- Whether the private sector can achieve the necessary subsequent reductions in cost needed to get from the cost of a FOAK demo to the target cost, i.e., the cost of an NOAK plant.

In this chapter, we assume that the Government would wish to proceed with a program to develop microreactors, then to encourage the use of the reactors at Federal installations. Going forward, there are significant technical and programmatic issues that need to be addressed, and often several options for pursuing each issue.

Here we attempt to present the issues, the options, the alternatives within each option, and the pros and cons of each alternative. With the information presented here, DOE will be in a better position to choose an approach to increasing resilience at Government facilities by using on-site microreactors.

Who would own the reactors operating at Federal installations?

The assumption here is that consistent with the results of the analysis for Scenarios 2, 3, and 4, NOAK microreactors will achieve the target cost around $4,000/kWe and will produce electricity that will be competitive with electricity produced by natural gas generators.

If the Federal Government decides to move forward with a campaign to improve resilience at Government installations, there are two options for ownership for these on-site generators:

1. Private ownership of these on-site generation facilities, or
2. Government ownership of these on-site generation facilities.

Within those two options, there are alternatives for actually procuring microreactors.

<u>The issue of financing costs</u>: In scenarios 2, 3, and 4, the cost of the microreactor increases significantly as the cost of financing the capital cost of the reactor increases. If low interest rates are only available for Government-owned projects, then the obvious path would be for the Government to own the reactors. If low-cost financing can be made available through an existing loan program or through some yet-to-be-enacted interest rate subsidy, then it might be possible for a private company to finance a purchase at an interest rate that would allow the reactor to be economically competitive with fossil fuel generators, such as natural gas.

Without advanced knowledge about the possibility of low-cost financing programs, we discuss the two options for microreactor ownership below.

<u>Option 1 – Private Ownership</u>

Private ownership implies that a private company would build and operate the reactors. The Government installation would merely buy power from the company that owns the reactor.

At this point, more than one company might be involved in any single project for power generation at a Government installation. For example, a vendor might obtain private financing for construction of the plant. The vendor could then sell the reactor to an owner/operator, who would operate and maintain the plant. The owner could then contract to sell electricity to the Government installation for a set time period.

In order to have an assured supply of power, the Government installation would need a contractual vehicle that would guarantee that the electricity would be made available to the Government installation. This contractual arrangement is typically a Power Purchase Agreement (PPA).

There are problems with the use of a PPA. First, utility power purchase contracts are currently limited to 10 years[lxiii], while lenders and owners might need contracts as long as 40 years in order to be sure that they can recover their investment. Second, the owners may require a PPA that will lock in a price for the duration of the contract. This is normally called a take-or-pay contract and would insulate them from a potential loss in the future, but it would restrict the Government installation from being able to negotiate prices in the future. Third, we have to assume that the cost of electricity from on-site generation may exceed the cost of electricity purchased from the local utility. The Government installation will need authority to buy the electricity for the purpose of enhancing resilience, which might mean authority to buy the electricity above the market rate in order to demonstrate the technology, and currently the Government does not have that authority. Fourth, Government installations are often required to purchase power following the rules of the local Public Utility Commission (PUC). In cases where the local PUC grants a monopoly to a local utility, that utility may need to be the owner of the plant. The Government installation would either have to deal with that supplier, or obtain an exemption based on the fact that the investment is being made in order to enhance resilience.

Advantages and Disadvantages:

The benefit of private ownership is that the Government would be relieved of any responsibility for delivering the electricity to the Government installation. The provider of the electricity would be treated like any other private contractor providing services at the Government installation. Given that GSA can provide utility services to Government installations, it might be possible for GSA to hold the actual contract for the delivery of electricity at a particular installation. In that scenario, GSA would interface with the electricity provider and the particular installation would simply pay a monthly bill to GSA for the new utility service, in the same way in which agencies pay GSA to rent their buildings.

The disadvantage of private ownership, aside from the contractual issues sited above, is the potential higher cost of this option – primarily the difference between the cost of Government borrowing and the cost of private financing, including profits. Our analysis, as shown in Chapter 3, clearly illustrates this issue. In order for a microreactor to be cost competitive with electricity from a generator fueled by natural gas, it may be necessary for the Government to establish a way to subsidize interest payments. A loan guarantee is one such option, if the resulting rate of borrowing for the private owner can be as low as 2% to 4%.

With its existing authority DOE could offer a loan guarantee to subsidize the construction of a reactor. The problem here is that loan guarantees have typically been used to subsidize risky individual projects where the Government wishes to reduce the financial exposure posed by the borrower for such a project. They have not been considered to be used again and again, for commercially available equipment, each time the Government wants to secure the output of another plant for a Government installation.

Ultimately, the Government would be faced with a decision to balance the advantage of private ownership, i.e., eliminating any management responsibility and liability on the part of the Government, with the disadvantage of private ownership, i.e., the potential cost of this option.

Other approaches considered:

We considered other approaches to subsidizing the cost of a privately owned microreactor. Some approaches are not applicable; some are difficult if they involve legislation; some are possible if they can occur through Executive Order. We provide some specific examples below.

- ESPCs and UESCs: Energy Savings Performance Contracts (ESPCs) and Utility Energy Service Contracts (UESCs) refer to contracts that foster conservation and energy savings[lxiv]. The implementation is complicated. A subset, an Energy Savings Performance Contract – Energy Sales Agreements (ESPC-ESA)[lxv] provides a structure similar to the use of PPAs (purchasing utility services at a fixed price), but for distributed energy systems (only Solar and Wind), and only for the case where there are projected energy savings and cost savings[lxvi]. The utility then creates "Renewable Energy Certificates" which it can sell to reduce the price of the ESPC-ESA. Note that this authority extends to private financing of projects.[lxvii] This is simply another back-door approach to subsidizing wind and solar, but it deserves two comments.

1. There seems to be no direct reference exempting this approach from the Anti Deficiency Act. Thus, there is no backup for the assertion that this financial machination allows an agency to avoid up-front budget authority to enter such contracts.
2. For the current analysis, on-site generators are used for the purpose of increasing resilience, not for energy savings. This application requires batteries and results in extra costs rather than cost savings. As a result, ESPC types of contracts would not apply to the current situation.

- Legislation to establish a level playing field for small nuclear technologies. Currently, subsidies for various sources of energy are difficult to rationalize. The government has available investment tax credits, e.g., up to 22% for solar installations[lxviii] . The government also provides production tax credits, e.g., 2.37 cents/kWh for wind in 2018 (This number escalates with inflation[lxix]) and 1.8 cents/kWh for advanced nuclear facilities.[lxx] (This number does not escalate with inflation.)

Tax expenditures are the amounts claimed under the above authorities. For 2018, tax expenditures for various energy sources amounted to $18.1 billion, of which 0.1 billion applied to nuclear technologies[lxxi]. There were no expenditures claimed under the production tax credit for advanced nuclear facilities in 2018 because no advanced facilities were up and running in 2018.

Table 7.1: Energy-Related Tax Preference 2018

Source	$ Billions
Fossil	3.2
Renewables	9.8
Efficiency	0.4
Biodiesel	3.4
Plug-in vehicles	1.2
Nuclear decommissioning fund	0.1
Total	18.1

The Taxpayer Certainty and Disaster Tax Relief Act of 2020, passed as part of the Omnibus Bill, extends most of these subsidies, without addressing any new subsidies for nuclear energy. (See Appendix K, Division EE).

It remains to be seen whether new subsidies for nuclear facilities will be proposed in the Biden Administration.

- Establishing a consistent standard, and applying it uniformly to all generating technologies, for the social benefit of avoiding emissions of CO_2. This is essentially the same issue as for qualifying facilities under the Public Utility Regulatory Policy Act (PURPA)[lxxii]. Various social costs have been associated with the production of CO_2[lxxiii] and various proposals have been offered to either tax carbon emissions or otherwise provide incentives for fuels that do not produce CO_2. The Biden Administration currently favors a social cost of $51 per ton.[lxxiv]To date, no legislation has been passed, but the Obama Clean Power Program offered the opportunity for nuclear power to be considered on the basis that it does not produce CO2.[lxxv]

The Biden Administration has indicated that it will not simply revive the previous Clean Power Program but will rather "look for its own solution to limit power plant carbon".[lxxvi]

- There is always the possibility that a new subsidy could be proposed specifically for small reactors to provide on-site power at Government facilities. Nevertheless, the entire market for this application is potentially large (around 200 Government installations). It is not clear that Congress would entertain a new set of subsidies for this inherently Government market.

Option 2 – Government ownership

Government ownership implies that the Government would contract for the construction and operation of the microreactors. The Government-owned facility would then generate the power for the installation, and the Government would have a guaranteed supply of power.

There are two alternatives.

Alternative 1: Each agency owns its generators:

There are a large number of administrative and legal issues that would have to be overcome in order for each agency to own its own microreactors. Over the next 10-20 years, it might be possible to overcome these issues, but today they would be time-consuming for the agencies, and could well result in diverting resources away from the real missions of the agencies. First, each agency would need to deal with the NRC at the start of the project, i.e., construction, start-up and operation. Second, there are technical items (e.g., decommissioning) and on-going regulatory factors (e.g., on-site NRC inspections) associated with nuclear reactors. Today, most agencies do not have the ability to deal with such items. That situation could change over the next 10-20 years, however, if the NRC's current regulatory regime were to be revised to accommodate the unique aspects of microreactors. New rules for siting, staffing and security requirements could, in the future, provide the ability for microreactors to operate in a way that would be similar to on-site natural gas power systems.

Should an agency wish to own and operate its own microreactors, legislation would be needed to authorize such ownership. Today, only DOE, DOD and NASA are authorized to incorporate nuclear generating technologies into their programs. Today, these agencies have the ability to purchase a reactor from a vendor as a turnkey (historically, a fixed-price operation) and use a private firm with nuclear expertise for operations.

At present, as microreactor power systems are still being developed and demonstrated, and have yet to go into operation, it may be premature to expect that individual Government agencies would own and operate their own systems. For the near term, possibly for the first several applications of microreactors at Government installations, single agency ownership may be the logical first step. Eventually, that approach could evolve to individual ownership by participating agencies.

Alternative 2: A single agency owns the generators:

Given the problems associated with each agency owning its own plants, it might be logical for a single agency to procure the reactors for installation at Government sites, and to operate and maintain the reactors at each of the Government installations. There are several advantages to this approach.

With single-agency ownership, the Government could achieve a uniform way to manage the plants and a standard approach to deal with problems that might occur at different sites. During operations, a single technical group could deploy the necessary on-site personnel, schedule and manage maintenance at all the reactors, and ensure a consistent level of oversight and interaction with the NRC. Such an approach would also be an efficient way to lay the groundwork for eventual ownership by individual agencies. Ultimately, as in the case where each agency owns its on-site generators, a single Government agency might choose to purchase reactors from a vendor as turn-key operations and use a private firm with nuclear expertise for operations.

The concept of a Government program to own reactors at possibly up to 200 federal installations immediately raises two issues: the type of organization that might be charged with such a program, and the type of financing that might be appropriate. Specifically, the Government would need the ability to provide up-front construction costs of possibly $1.6 billion (based on reactor costs $4,000/kWe, and the Government acquires up to 200 reactors at 2 MWe each) over at least a decade, plus a way to manage revenues as Federal installations pay for the electricity.

As for the organization, the Government has two alternatives, either manage the program through an existing agency such as GSA or DOE or create a Government Owned Enterprise for the purpose of managing the program as a business. Should the Government choose to place the program in an existing organization, the program might be managed like the old Uranium Enrichment Program, funded through annual appropriations, with revenues offsetting the appropriation. Should the Government choose to create a new Government Owned Enterprise[lxxvii], that approach would most likely involve creating a new revolving fund in Treasury. The revolving fund would receive an initial appropriation, after which it would conduct its business using revenues.

Funding the necessary Research and Development (R&D) for Microreactors:

Regardless of ownership, to establish the need for an R&D program, consider that microreactors are, as yet, not available for installation at Government facilities. In order for a company to be able to sell a microreactor in the commercial market, the reactor will need an NRC license. In order to obtain such a license, a reactor will need to be demonstrated to the satisfaction of NRC, which leads to the necessity of building a first-of-a-kind (FOAK) plant - for any design that expects to get an NRC license.

Today there are yet outstanding technical readiness issues that need to be resolved before a company can attempt to build its FOAK demonstration plant. The purpose of an R&D program is to resolve those technical issues and prove that a microreactor can eventually be competitive in the market for on-site power.

We note that the FOAK demonstration plant need not necessarily achieve the target cost we have been using in this study. As shown in Figure 7.1, a recent NEI report[lxxviii] estimates that, if an FOAK plant can be built for about $10,000/kWe, the nuclear industry should be able to reduce the cost of future plants down to the target cost. Similar learning curves have been observed in the power industry[lxxix].

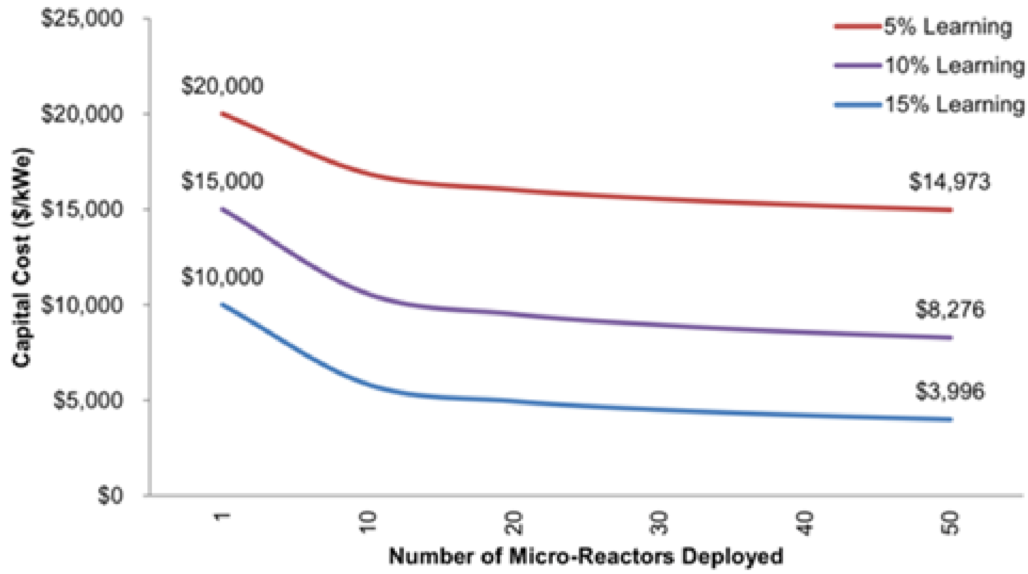

Figure 7.1: Microreactor Learning Curve Capital Cost Reduction (NEI)

Given the above rationale, we believe that the goal of a successful microreactor R&D program should be to demonstrate that a microreactor design is technically ready and can be built for a cost close to the lower curve in the above NEI graph. After a review of the literature, we believe that a reasonable target for a FOAK demonstration plant might be the medium cost chosen for this study, about $12,000/kWe.

For completeness, before discussing the DOE programs, we need to acknowledge that DOD is also engaged in microreactor development. Project Pele is a feasibility study of the potential for mobile microreactors that would meet DOD needs[lxxx]. As with other DOD programs, the specifications for these reactors emphasize the ability to meet mission requirements, rather than economic goals. Indeed, Naval Reactors already produces reactors in the operating range of microreactors, but at higher costs than could be supported commercially, and with fuel requirements that are currently not feasible for the commercial market.

Current DOE Advanced Reactor programs

DOE takes a two-pronged approach to the development of advanced reactors, and any future program of R&D for microreactors needs to fit within, or emerge from, the current DOE program. Here we describe the current program to provide the context for a potential effort that would be focused on microreactors.

First, through a collection of individual efforts, DOE subsidizes private companies to develop and demonstrate advanced reactors. These efforts include:

An Advanced Reactor Demonstration Program (ARDP)[lxxxi], mandated by Congress in the 2020 appropriations Act.[lxxxii]. It has three parts[lxxxiii]. The first part provides for DOE to demonstrate two advanced Reactors. DOE has chosen two Small Modular Reactors (SMRs). One SMR is fast spectrum sodium-cooled design at 345 MWe[lxxxiv] and the other SMR is a thermal spectrum gas-cooled design at 80 MWe[lxxxv]. Both are planned to be fully functional by 2027[lxxxvi]. This program assumes that these reactor designs are technically mature enough from past R&D investment that there is no need for further R&D and that these plant designs can proceed directly to demonstration. The implicit assumption is that (a) the technology base is adequate and (b) that the plants will demonstrate that SMRs can be competitive with LWRs. If either of these assumptions is not valid, this program runs the risk of demonstrating that, on the basis of capital cost ($/kWe installed) SMRs may be more expensive than LWRs for commercial deployment.

This ARDP program also provides funds for "Risk Reduction" for industry teams to "solve technical, operational and regulatory challenges to support possible demonstration within 10-14 years"[lxxxvii]. The third part, "Concept Development", provides for three teams to "solidify their design concept to mature technology for potential demonstration by mid-2030s"[lxxxviii].

Taken together, DOE is now funding a program that is meant to provide eventual demonstrations of 10 different designs for advanced reactors. The eventual demonstrations will establish the cost of each FOAK plant and will provide companies with the information necessary to bring their cost into a range that will be competitive.

A similar approach could be used specifically for the development of microreactors.

<u>Two additional programs have been authorized in the Energy Act of 2020 (See Appendix K)</u>

- The first provides for a demonstration of two jointly operated integrated energy systems, at least one of which is a nuclear reactor. [See Appendix K Title II Sec 2003 (c)].
- The second is somewhat more relevant to the current study. It authorizes an Advanced Reactor Demonstration Program, for which the Congress had previously appropriated funds in FY 2020. [See Appendix K Sec 959A]. This provision emphasizes both economics and the possibility of using such a reactor to demonstrate "backup or mission-critical power supplies" [Appendix K. Sec 959A (b)(A) and (D)]. There exists the possibility that this program could be expanded in the future to become an ARDP program for microreactors.

The second prong of the two-pronged approach is an ongoing R&D program managed by DOE and funded through annual appropriations. It focuses on more basic technology development and has the flexibility to emphasize technologies relevant to microreactors. As described in DOE Budget documents,

- The Transformation Challenge Reactor:
  "…will support the progression of activities associated with an operational test of a microreactor fabricated using additive manufacturing techniques[lxxxix].
- The Advanced Small Modular Reactor R&D program:
  "…reflects a focused emphasis on cost-shared, early stage, and limited later-stage, design-related research and development (R&D) relevant to a broad spectrum of advanced small modular designs while minimizing potential duplication of effort with the Advanced Reactors Technologies subprogram[xc]."
- The Advanced Reactors Technologies subprogram:
  "…will address high-value fundamental research for long-term concepts, early-stage research and development (R&D) needs of promising mid-range concepts, development of innovative technologies that benefit multiple advanced reactor concepts, including emerging microreactor designs, and stimulation of new ideas for transformational future concepts."[xci]

These last two activities seem to lack focus and the time-urgency of the mandated demonstration programs.

The question of possible organizational structures for the microreactor program:

Provisions in the Energy Act of 2020 seem to address the possible lack of focus in the current R&D program by providing a detailed list of the technologies and potential applications to be pursued by DOE. Provisions include a mandate that DOE entertain diversity in designs and requires evaluation criteria for choosing a demonstration project. Indeed, it requires an external review of project by a panel, at least one member of which has no conflict of interest. (Sec 959A (c)(1) and 3(A)). The Act, nevertheless, stops short of commenting on the efficiency of the current DOE organization, or whether the organizational structure at DOE might be improved.

Should DOE - NE wish to focus the microreactor program within its current organizational structure, NE might engage the several offices involved in developing a plan that would develop an R&D program specifically for microreactors. Such a plan would involve coordination among the several DOE offices, and would establish a timeline and budget to advance the technology for microreactors to the point where DOE could segue into a new ARDP program, specifically for microreactors.

As a step further in being able to manage the program after a program plan is in place, DOE might consider consolidating the program in one of its existing offices and switching budget responsibilities to that office. In addition, our research has suggested that a large part of the input for the program currently comes from companies interested in funding opportunities. We suggest that DOE might wish to balance that input, as noted in the Energy Act [Sec 959A 3(A)] with former industry and lab experts as well as senior academics with practical design experience and no conflicts of interest.

Should DOE wish to tap the expertise of a program that already has expertise in building small reactors to meet Government mission requirements, DOE might consider establishing a separate program office, possibly centered at one of the two labs that have no direct conflict but have unique design experience in small reactors: either KAPL[xcii] or Bettis[xciii] .

Mechanisms for Engaging with Industry Vendors for R&D

DOE has available a number of approaches to support R&D for these reactor concepts:

- DOE could offer the use of vouchers. Vendors could perform required R&D activities at DOE labs. DOE could then fund the labs directly to provide the required support for the contractors. Vouchers form the basis of the GAIN program funded by DOE-NE.
- DOE could enter into cooperative agreements for work to be done at DOE labs. While a company would pay the full cost of the R&D, this Strategic Partnership process[xciv], previously called Work for Others, provides access to DOE facilities and a clear path for the contractor to retain rights to intellectual property after the work is finished.
- Regulatory Assistance Grants can be offered to subsidize cost of resolving issues between industry and NRC.
- Provide funding for Risk Reduction and subsidies for advanced designs, as is being done under the current ARDP program.
- Offer financial assistance, as it did with NuScale in 2013, 2015 and 2018[xcv].
- Provide financial rewards as lump sum payments upon meeting specific milestones, as implemented by NASA in its Commercial Orbital Transfer System (COTS) program and articulated in section 9005 of the Energy Act of 2020.

In all cases, continued DOE support would need to be accompanied by clear management directives imposed on the recipients. First the beneficiaries would need to be responsible for meeting technical milestones. Second, the purpose of the R&D would ultimately be to demonstrate technical readiness and to identify the cost of various components and systems, and to focus on cost reduction. The Government would need assurances that its contribution would lead to an affordable FOAK plant. Under the recently passed Energy Act of 2020 (EA-2020), DOE has specific authority to impose all of the above requirements on its contract recipients. [See Appendix K. Sec 959A, (d) and Sec 9005]

Government microreactor R&D program needs basic information that is not currently available

Based on our effort to obtain information from the vendors, we concluded that the Government needs much more information before it would be able to make an informed decision to support any of the designs currently being proposed for future development for microreactors. There seem to be no publicly defensible estimates of the cost of a FOAK plant, nor a consistent way to estimate that cost, nor detailed plans for an R&D effort that would identify key areas where work is needed to reduce costs, nor any convincing explanations for ways to reduce costs to target values as more plants are ordered.

As an example of information that needs to be available, DOE depends on a numeric value for TRL to indicate readiness. What little evidence we were able to find to back up this value seemed to relate to the reactor core, not for other key equipment like the power conversion components. If the balance of plant is not included in the estimate of TRL, readiness could be overstated. There is also some indication that vendors assume that the efficiency of the balance of plant will be the same as for LWRs. That assumption may not be correct. If the efficiency of the balance of plant for SMRs is less than for LWRs, the result could be an increase in the cost of the ultimate product.

Without such necessary information, the Government is left in a position of having little independent ability to evaluate the various designs being proposed, and little ability to justify any funding level for R&D associated with any one of the designs. The situation is made worse because it is likely that the vendors have not used any common basis for their proprietary estimates of cost.

Basically, before making a commitment to a specific design and an ARDP approach that would lead to an eventual demonstration, the Government needs a solid estimate of the content of an appropriate R&D program, an estimate of the cost of that R&D program, and an estimate of the risk, i.e., the probability that the ultimate FOAK plant can be built for about $12,000/kWe. Only with that information for several designs can the Government make an informed decision on moving forward to assist potential vendors in developing products based on one or more of the designs currently under consideration.

If the Government decides to fund a demonstration without such information, the ultimate goal of the program could be put at risk. If an FOAK plant ends up with cost over-runs, or if there is no clear path to get to an NOAK plant that achieves the target cost of $4,000/kWe, then the program may end up undermining its goal, unable to demonstrate that a microreactor can compete with a gas fired generator.

Government R&D program needs a methodology and staff to evaluate cost estimates and R&D plans

Once DOE has the information necessary to start a focused R&D program, the program needs specific technology and cost goals. Without such goals, there is a danger that the R&D effort could be never-ending, and that the FOAK plant would never get built. Thus, we see the need for an R&D program characterized by both technical and economic goals, with milestones and decision points as to when to continue the R&D and when to decide that the R&D has proceeded to the point where DOE would be confident that a vendor could build a FOAK plant for about $12,000/kWe.

Currently, DOE depends on its Technology Readiness Assessment Guide (DOE G 413.3-4A)[xcvi] to ensure that projects and their attendant costs are being controlled - and this process starts with "R&D input"[xcvii]. Our concern is that DOE needs a way to obtain and evaluate information on each design in order to provide this R&D input.

Basically, a program to develop microreactors requires a cost analysis methodology that could be applied consistently to all the designs to evaluate readiness and estimated costs. We note that IAEA has made a start in this direction with its Advanced Reactors Information System (ARIS).[xcviii]

It could be challenging for DOE to develop such a methodology. The process would need to start with the cost and maturity of each of the components of a particular design, e.g., pumps, compressors, etc., on the way to determining the cost and maturity of key components and the complete system. If many of the components are off the shelf, if the vendor just buys them, they need not be included in the cost of the R&D unless quality assurance requirements need to be more rigorous. In any event, the analysis would focus on the cost and maturity of the key components that truly need validation through research, and the model should provide a consistent way to price out the R&D needs of each of the designs. It would enable DOE to identify a cost associated with R&D that would actually be necessary, as opposed to simply accepting estimates provided by vendors. The IP issues associated with this approach could be handled through non-disclosure agreements and team composition auditing, as has been done in DOE and DOD technology acquisition assessments for semiconductors, sensing systems, etc.

The task of developing the capability to model and assess the economic potential for various designs would be a new effort within DOE-NE. It would necessarily involve a group of independent experts that could develop such an analysis approach, have the ability to require the vendors to provide the information necessary to do analyses, and provide unbiased results to DOE.

In the conduct of the current effort, we were struck by the need for an R&D plan that starts with the ability to evaluate the actual needs and purposes of the R&D being suggested by various companies. Specifically, when companies did provide cost estimates for R&D, the cost estimates varied widely. In addition, without the necessary information from the companies, we had little ability to compare the stated needs of individual companies.

In our interactions with vendors, we heard estimates for the cost of R&D that vary from around $30 million up to around $200 million. These estimates obviously include work that is applicable to similar designs but, from a vendor's point of view, that cost estimate was deemed to be necessary to support that vendor's specific design. Before allowing each vendor to propose a suite of R&D activities and costs associated with their specific design, DOE needs the capability to identify common research needs and fund them so that the research results would benefit all vendors using similar designs. DOE has several reactor working groups that are attempting to identify such research needs. It is important that DOE effectively uses these working groups so their recommendations are implemented in the DOE program.

These items comprise a category called precompetitive research. As shown in the DOE budget documents, the many DOE R&D efforts are in fact a suite of programs that could be focused as precompetitive research in support of specific designs. And indeed, DOE already acknowledges that it seeks input from industry.

> "The ART subprogram focuses on early stage, industry-informed R&D priorities that could provide widely-applicable benefits across many different advanced reactor concepts."[xcix]

All that remains is a formality that would put the appropriate sub-programs within an overall program in support of a specific design.

A sub-program for developing precompetitive technologies could be developed by having vendors form a consortium to advise the Government on the R&D needed to develop specific technologies that have general application[c]. A plan developed by such a consortium could then be implemented by the DOE labs, with strong technical oversight from DOE to ensure that the program remains coordinated to achieve the deliverables identified by this process.

Microreactor Demonstrations: Why? Where?

Having accomplished the R&D goals, i.e., being able to validate the expected cost of an FOAK demonstration plant, the next step would be to move to an ARDP-type program specifically for microreactors.

If we assume that an FOAK plant can be built for $12,000/kWe and that it may be necessary to demonstrate a 2 MWe plant in order to qualify for a regulatory license, then a single demonstration plant could cost $24 million. An ARDP program that would lead to a demonstration of five such plants could cost $120 million, almost a factor of 40 times smaller than the proposed cost of the Virtual Test Reactor (>$4 billion).

If the Government wants to provide for multiple demonstration plants, DOE could provide the venue(s). One possibility might be to choose a single venue such as the National Reactor Innovation Center[ci] (NRIC) site in Idaho, at least for the first few demos. This would allow the same team of technical experts to demonstrate each of the designs and would lead to a consistent approach to the demonstrations. Another approach might be to place individual demonstrations at different DOE laboratories. In this approach, a single group like the National Reactor Innovation Center (NRIC) could still be in charge of the program, but each demo could be integrated into a different electricity distribution system, complete with a utility connection. In that way each of the demos could be tested on its viability in a different environment, and DOE could discover and resolve problems as they arise in different regulatory and physical environments.

Once a demonstration is completed for a particular design, DOE would then be able to judge the potential that one or more of the designs could achieve the target cost of $4000/kWe for the NOAK plant. At that point, DOE could then start entertaining orders for plants at potentially interested Government installations.

Recognize, however that there is risk associated with this proposed approach, just as with the current ARDP program. Should DOE fund a handful of the microreactor designs, it is likely that one or more of them would fail at some point and never receive a license. In that case, DOE would take a loss on its investment in that design.

Who pays for what?

Current law[cii] requires the vendors to pay 20% of the cost of R&D, and 50% of the cost of a demonstration plant. Current law also provides DOE with the ability to eliminate these requirements if the Secretary determines that such action is necessary and appropriate.

Since this law was enacted in 2005, DOE has focused on the requirements for cost sharing and ignored the flexibility it has to eliminate the requirement for cost sharing. One can argue that the law was written to apply to cases where a company approaches DOE and seeks a subsidy, i.e., funds to develop and then demonstrate a commercial application that would then be owned by the company. On the other hand, it is a somewhat illogical stretch to apply the provisions for cost sharing to projects where the Government has a valid national security requirement, where the Government simply needs a company to develop and demonstrate the technology needed to satisfy that Government requirement. As an example, the PELE program, currently underway at DOD, calls for industry to develop a mobile microreactor for use on DOD bases. DOD avoids the need for cost sharing by using a provision in its Other Transaction Authority (described below in more detail).

So while there is a case for cost sharing, there is also a case for eliminating the requirement when the Government is simply interested in buying a product to serve a national mission.

If a 2 MWe FOAK plant costs $24 million, and if DOE decides to have vendors build five such demonstration plants, the total cost would be $120 million. If industry were to be responsible for half that amount, DOE could "save" $60 million by requiring cost sharing to take a particular design through a demonstration.

A requirement for cost sharing would also guarantee that the vendor has a financial stake in the program, a real commitment to the success of the R&D and the success of the subsequent demo. The downside of such an approach becomes apparent when one looks at the financial situation of several of the companies that might be potential vendors. Several of these companies are small, essentially start-ups. They may have the technical talent and an excellent design that would ensure success in the R&D and would enable them to secure an NRC license, but they may be unable to secure the necessary private financing that would allow them to participate in the new program. Thus, a requirement for cost sharing might narrow the number of designs that could eventually form the choices for on-site power at Government installations. Maybe more importantly, a requirement for cost sharing could be seen as a back-door way for the Government to eliminate small companies and favor already-established nuclear vendors.

If DOE were to eliminate the need for private financing, the cost of five demos would increase by about $60 million. Nevertheless, DOE would be seen as trying to expand the base of vendors and create an industry that would, in the future, be subject to competition among the vendors. Further, one might hope that the existence of several competing vendors would serve to further drive down prices in the future. As a result, over the next 10-20 years, the Federal Government might be able to acquire these microreactors at a lower cost and the overall program, installing reactors at Government installations, could possibly be a lot less expensive. Further, if the reactors become less expensive, there could be a substantial commercial market for microreactors.

In summary, DOE would face a challenging policy decision: require cost sharing or not. Each alternative would involve financial implications in the near term, and each would drive the future market for microreactors in a different direction: near term budget savings with fewer vendors in the market, versus a higher level of expenditures in the near term, but more vendors and more competition in the market. Should either alternative prove too drastic, DOE has the ability to reduce the level of cost sharing, without eliminating the requirement.

Placing the Government contracts:

Once DOE has a set of requirements for the FOAK plants, the Department has two options for placing the necessary contracts for the procurement of a demonstration microreactor. The two general classes for engaging industry in DOE projects are standard contracting mechanisms, and an alternative funding mechanism that has recently come into increased usage, especially in DOD.

Standard mechanisms include[ciii]:

- Requests for Proposals (RFPs): used when DOE is procuring services.
- Funding Opportunity Announcements (FOAs): used when DOE is interested in a cost-shared project.

DOE has a history of using these various standard mechanisms to engage industry in DOE projects. Further descriptions in this study would add little to DOE's familiarity with, and DOE's use of these various mechanisms.

The latest favored alternative funding mechanism - OTAs

Other Transactional Authority (OTA) is a still-evolving alternate to standard contracting for R&D, as well as for projects involving a prototype that is based on that R&D. The authority is somewhat complicated because it is described as a process specifically for DOD. In subsequent legislation, the authority is granted to other agencies, including DOE.

The potential use of OTA is worth a short review. The concept originated with the NASA Space Act in 1958. Authority for DOD to use OTA for R&D was created in FY 1989, and that authority has been amended or modified nearly every year since[civ]. Currently 9 agencies have OT authority[cv]. As of the passage of the Energy Act of 2020, DOE's OT Authority, extends through the end of FY 2030. (Appendix K. See Sec 9006).

OTA is basically a way to enable DOD and some other agencies to pursue research projects while avoiding much of the hassle of dealing with the Federal Acquisition Regulations (FARs). It is noteworthy that, rather than explicitly exempting OTA from the FARs, the authorizing legislation preferred to define OTA in the negative; an OTA project is <u>NOT</u> a contract, cooperative agreement or a grant- the three mechanisms that are in fact subject to the FARs[cvi]. The legislation thus allows the agency to choose contractors for R&D projects without the need for a competitive process (a requirement of the FARs). Beginning in FY 1994, DOD could also use OTA to fund prototype projects that derive from an R&D effort, but in this case the agency needs to use a competitive process to choose the contractor for the prototype project[cvii]. The OTA authority also covers the participation of consortia and contains a qualified requirement for a private contribution of one third of the cost of a prototype. Specifically, the need for one third cost sharing is eliminated if there is significant participation by a nontraditional defense contractor, a nonprofit, or if all the participants are small businesses[cviii].

Because the process of using OTA is complicated, within DOD there is official guidance on when and how to use OTA[cix]. Nevertheless, the rapid growth of OTA ($2.1 billion in FY 2017) has led to warnings, both from within and outside the Department about the potential pitfalls associated with using OTA[cx]. In addition, the rapid growth of OTA in DOD has led Congress to express concerns about implementation of the authorities associated with OTA[cxi].

The result of this evolving authority is that, at the current time, OTA would allow DOE to avoid competition in its decision to choose a contractor for a particular technology during the R&D phase but would require a competitive process in choosing a contractor for a prototype (demonstration). It would require 1/3 cost sharing unless the contractor were a consortium dominated by a nontraditional contractor, or a nonprofit, or if all the members of the consortium were small businesses.

If DOE wished to do so, DOE could eliminate the need for cost sharing - either by using Other Transaction Authority, or its authority under Sec 988 of the Energy Policy Act of 2005.

Should DOE wish to have OT Authority available for an eventual campaign to build microreactors at Government installations, note that OT authority for DOE currently expires on September 30, 2030 (See Appendix K Sec 9006).

Potential for Cost recovery:

Up to this point, everything in this study has assumed that a "Government buy" of maybe five FOAK microreactors, could lead to competition among vendors, which could bring down the cost of an NOAK plant, hopefully down to about $4000/kWe.

It is important to note such cost reductions could then result in a significant boost for future sales in the commercial (non-Government) market for microreactors.

This anticipated future, the expectation of commercial sales of NOAK reactors, could have implications for the cost of the initial Government program. Especially if the Government decides against requiring cost sharing, the Government would be in a strong position to impose conditions on future commercial sales of any of the licensed microreactors that resulted from Government-supported R&D and a Government-funded demo. Specifically, as part of its initial contract with a vendor, the Government might require an up-front agreement that future commercial sales of the technology be subject to a "Government reimbursement fee". As an example, the Government might require a fee of 5% of the sales price of each reactor that derived from the initial Government investment in the technology. In such a case, the Government could recover its investment in the technology as each vendor sold its first 20 reactors. In addition, the Government might also require utilities to collect a surcharge in order to partially reimburse the Government for its investment in the initial R&D.

Should the Government decide to run the program within its existing operating programs, the revenues could be booked as offsets to an existing appropriation. Should the Government decide to create a new Government Owned Enterprise, the revenues would be deposited into the revolving fund associated with the new enterprise.

Again, there is risk associated with this proposal. One or more of the licensed reactors may never sell a commercial microreactor. In such cases, there would be no reimbursement to DOE. DOE could overcome this risk by increasing the reimbursement fee on reactors that do in fact achieve commercial sales but, at some level, a higher fee would dampen the demand for the licensed microreactor.

Summary Observations

Should the Government wish to pursue a program to encourage the use of microreactors at US Government installations, we recommend:

- A research program with milestones and a reasonable timeline that, if successful, would result in confidence that a FOAK plant could be built for about $12,000/kWe.
- A focused program in the Department of Energy capable of conducting the research program.
- A policy to coordinate the building one or more FOAK demonstrations when there is confidence that the cost of such plants would be around $12,000/kWe.

Then, assuming that the construction of FOAK plants leads industry to pursue further price reductions, and eventually offer NOAK plants at the target price used in this study, (~$4,000/kWe and reduced O&M costs), we recommend that:

- The Government decide on an organizational approach that could manage the construction and operation of a large number of microreactor generators (with a potential of possibly 200 plants).
- The chosen organization be accompanied by an appropriate financing mechanism that would provide the ability to recover revenues from the production of electricity by those plants.

Appendix A
Interagency Energy Management Task Force

The Interagency Energy Management Task Force is led by the Federal Energy Management Program director. Members include energy and sustainability managers from federal agencies.

Table A.1: Task Force Members as of July 2019

Organization	Primary Contact	Alternate Contact
General Services Administration	Mark Ewing	Karen Curran
National Aeronautics and Space Administration	Joan Hughes	Wayne Thalasinos
National Archives and Records Administration	Mark Sprouse	Ngan Pham
Smithsonian Institution	Thomas Reavey	Mike Fortin
Social Security Administration	Dwight Lucas	Scott Howard
Tennessee Valley Authority	Lee Matthews	Chris Azar
U.S. Army Corps of Engineers	John Coho	Antonia Giardina Lara Beasley
U.S. Department of Agriculture	Dean Johnson	Ed Murtagh
U.S. Department of Commerce	Kristin Thomas	
U.S. Department of Defense	CDR Walter Ludwig	Ariel Castillo
U.S. Department of Education	Richard Smith	
U.S. Department of Energy	Kevin Carroll	
U.S. Department of Health and Human Services	Kathryn Narvacan	
U.S. Department of Homeland Security	Crystall Merlino	Patricia Harrington Marie Britt
U.S. Department of Housing and Urban Development	Jacob Weisman	George Jones
U.S. Department of the Interior	Mary Heying	
U.S. Department of Justice	Chau Tran	Andrea Thi
U.S. Department of Labor	Susan Gilbert-Miller	Phil Puckett
U.S. Department of State	Nicholas Carros	Brian Platz Landon Van Dyke
U.S. Department of the Treasury	Glen Mondoni	
U.S. Department of Transportation	Hetal Jain	Brent Kurapatskie
U.S. Department of Veterans Affairs	Cynthia Cordova	Phyllis Stange
U.S. Environmental Protection Agency	Daniel Amon	
U.S. Postal Service	Carolyn Cole	Kristine Sedey
U.S. Office of Personnel Management	Morris Thompson	

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Appendix B
Government Installations and Specific Energy Needs

Table B.1: Information received from specific US Government installations

Installation* by Agency (2018-19)	Total Annual Energy (BBTU)	Electrical Energy (BBTU)**	Non-Elec. Energy (BBTU)	Electricity (Percent)	On-site Power (MWe)	Backup Power (MWe)	Installation on Grid
Dept. of Commerce							
NIST - Gaithersburg	1244.7	507.1	737.6	41%	11.4***	4.1	Yes
NIST - Boulder-CO	259.8	121.5	138.3	47%	0	1.8	Yes
Dept. of Energy							
Idaho National Lab (8 campuses)	1073.4	890.7	182.7	83%	0	only local	Yes
Los Alamos National Lab	2309.1	1466.1	843	63%	4	not clear	Yes
National Nuclear Security Site	NA	282.2	NA	-	PV (814MWh)	not clear	Yes
Pantex Plant	350.1	285.8	64.3	82%	Wind (163GWh)	not clear	Yes
Sandia National Lab (Abq.only)	870.8	860	10.8	99%	PV (780MWh)	9.6	Yes
Y-12 National Security Complex	1425.8	749.4	676.4	53%	(24.8MWh)	not clear	Yes
Dept. of Interior							
Park Service Glen Canyon National Rec. Area	395.8	395.8	0	100%	5.7	not known	partial
Dept. of Justice							
BOP - Federal Correctional Complex Butner	587.6	172.2	415.379	29%	3.1	not known	
Dept. of Transportation - Fed. Aviation Admin							
Technical City Atlantic City	241.1	225	16.1	93%	12	12	Yes
Aeronautical Center Oklahoma City	227.6	227.6	0.0	100%	8	8	Yes
GSA Wash. DC Central Plant	2543.1	225.4	2317.7	9%	4.6	2.5	Yes
Health & Human Services							
NIH - Bethesda (total)	4519.3	1800.6	2718.7	40%	23***	16.6	Yes
NIH - Bethesda (#10/35/49)	2411.4	403.5	2007.9	17%	see above	see above	Yes
NIH - Res.Triangle-NC	264.5	117.4	147.1	44%	0	NA	Yes
NIH - RockyMtnLab-CO	205.1	115.3	89.8	56%	0	NA	Yes
Dept. of Homeland Security							
USCG - Base Kodiak	241.1	90 (est)	151	37%	0	NA	Yes
NASA							
Johnson Space Center	1134.8	232.8	902.0	21%	11.9	5.4	Yes
Kennedy Space Center	838.2	121.0	717.2	14%	7.5	6.2	Yes
Social Security Administration							
Main Complex - Wood Lawn MD	232.4	98.3	134.1	42%	35.4	8	Yes
Dept. of Treasury							
Bureau of Engraving-1	248.7	146.4	102.3	59%	0	1	Yes
Bureau of Engraving-2	245.8	144.7	101.1	59%	0	1	Yes
USDA							
BARC Campus - Beltsville MD	495.4	405.3	90.1	82%	6.2	7.3	Yes
USPS							
New Jersey - International	174.3	119.5	54.8	69%	NA	NA	Yes
USNRC Nuclr.Reg.Comm. HQ	40.4	39.9	0.5	99%	0	0.6	Yes
* Installation >100 BBTU of energy consumption							
** BBTU = Billion BTU (1BBTU=293MWh)							
*** On-site power generation was part of ESPC program (Energy Savings Procurement Contract)							

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Appendix C
Developers from GAIN Advanced Nuclear Directory for 2020

DEVELOPERS

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Appendix D
Microreactor Vendors Summary

Table D.1: Westinghouse eVinci Microreactor Design

Parameter	Conceptual Design Value
E-Vinci Reactor Concept	
Reactor module type (e.g., H2O-cooled-Thermal-Rx)	Thermal spectrum
Reactor module design life (yrs.)	>3 years
Reactor module design capacity factor	Target goal > 98%
Thermal output of module (MWth)	Not Available
Electrical output of module (MWe)	1 – 5 MWe (est.)
Allowable power ramp up/down (%/min)	Not Available
Reactor coolant	Sodium Heat Pipes
Power conversion system	Brayton Cycle
Module transport plans (and fuel)	Road, rail, sea, air
Switchyard interconnection requirements	Standard IEEE 1547 and UL 1741 grid or microgrid configuration
Maximum module height (meters)	6.1m x 2.4m x2.6m ISO containers
Module exclusion area boundary (sq. meters)	Area < 4000
Total module area (if different)	-
Above ground exposure (above, at-grade, below grade)	Fixed and at-grade
Resiliency features (e.g., black-start, cyber-security)	Black-Start
Stored energy of core/primary system (based on T,P,V)	Low pressure heat pipes
Ultimate heat sink (air or water)	Air
Multi-module planned siting plan	Planned expansion capacity
Fuel type	UO_2 or TRISO
Fissile enrichment (% fissile fuel)	5 – 19.75% ^{235}U
Refueling period (# full-power-years)	>3 years
Refueling requirements (on-site, cartridge core…)	Refueling at factory
Decommissioning requirement	Restore to Green Field
Required on-site personnel per module	2 per shift (est.)
Personnel breakdown (operations, maintenance, security)	Not Available
Control system autonomy vs. required operator actions	Autonomous operation, monitoring required
Estimate deployment schedule	On-site installed <30 days
Estimated overnight capital cost range ($/kWe)	Not Public
Estimated fuel cost range ($/MWh)	Not Public

Public Information:

- https://www.westinghousenuclear.com/Portals/0/new%20plants/evincitm/GTO-0001_eVinci_flysheet_RSB_03-2019_003.pdf?ver=2019-04-04-140824-613
- https://www.youtube.com/watch?v=Sh6BKKFxN_g

Table D.2: Holos Quad/Titan Microreactor Design

Parameter	Conceptual Design Value
HOLOS Reactor Concept	Closed Loop, Nuclear Powered Turbo Jet
Reactor module type (e.g., H2O-cooled-Thermal-Rx)	He/CO2 Cooled, Variable Geometry Assembly
Reactor module design life (yrs)	60 years (3 fuel loads)
Reactor module design capacity factor	N/A
Thermal output of module (MWth)	<2MW/m^3
Electrical output of module (MWe)	13 - 81 MWe, based on # of units and configuration
Allowable power ramp up/down (%/min)	Faster than LWRs via geometric rearrangement
Reactor coolant	He/CO2
Power conversion system	Closed-Loop Brayton
Module transport plans (and fuel)	ISO container, potentially airlift capable
Switchyard interconnection requirements	Not Available
Maximum module height (meters)	Fits within ISO container (~8ft)
Module exclusion area boundary	<1000ft
Total module area (if different)	ISO Container
Above ground exposure (above, at-grade, below grade)	Variable
Resiliency features (e.g., black-start, cyber-security)	Passive air cooling (active and emergency), fully automatable, built to withstand eternal events
Stored energy of core/primary system (based on T, P, V)	Not Available
Ultimate heat sink (air or water)	Air
Multi-module planned siting plan	Yes, stacked ISO containers
Fuel type	TRISO-based
Fissile enrichment (% fissile fuel)	Up to 19.95%, more likely 10-15%
Refueling period (# full-power-yrs)	<10 [EFPY]
Refueling requirements (on-site, cartridge core…)	Cartridge Based
Decommissioning requirement	Fits in standard spent fuel cask
Required on-site personnel per module	Not Available
Personnel details (operations, maintenance, security)	Not Available
Control system autonomy vs. required operator actions	Mainly autonomous
Estimate deployment schedule	30 days
Estimated overnight capital cost range ($/kWe)	Not public
Estimated fuel cost range ($/MWh)	Not public

Public Information

- http://www.holosgen.com/about-us-1-2/
- https://gain.inl.gov/SiteAssets/Micro-reactorWorkshopPresentations/Presentations/22-Filippone-HOLOS_DOE%20GAIN_6-18-2019.pdf

Table D.3: Hydromine Nuclear Energy LFR (TL-X)

Parameter	Conceptual Design Value
Hydromine TL-X Reactor Concept	**Preliminary concept design. Full design by 2030.**
Reactor module type (e.g., H2O-cooled-Thermal-Rx)	Liquid metal cooled fast reactor (pool type)
Reactor module design life (yrs)	30
Reactor module design capacity factor	Not available
Thermal output of module (MWth)	60MWth
Electrical output of module (MWe)	20MWe
Allowable power ramp up/down (%/min)	Not available
Reactor coolant	Lead
Power conversion system	Not available
Module transport plans (and fuel)	Not available
Switchyard interconnection requirements	Not available
Maximum module height (meters)	3.5m (reactor pressure vessel height)
Module exclusion area boundary (sq. meters)	Not available
Total module area (if different)	Not available
Above ground exposure (at-grade, below grade)	Not available
Resiliency features (e.g., black-start, cyber-sec.)	Active and passive safety systems
Stored energy of core/primary system (based on T, P, V)	Atmospheric pressure; primary system specific volume less than 1cubic meter per MWe.
Ultimate heat sink (air or water)	Not available
Multi-module planned siting plan	Not available
Fuel type	LEU, cylindrical cassette
Fissile enrichment (% fissile fuel)	19.75%
Refueling period (# full-power-yrs)	>100months
Refueling requirements (on-site, cartridge core…)	Not available
Decommissioning requirement	Not available
Required on-site personnel per module	Not available
Personnel details (operations, maintenance, security)	Not available
Control system autonomy vs. required operator actions	Instrumentation and control system does not require operator action to shutdown reactor at any time
Estimated deployment schedule on-site	Not available
Estimated overnight capital cost range ($/kWe)	Not public
Estimated fuel cost range ($/MWh)	Not public

Public Information: IAEA, Advances in Small Modular Reactor Technology Development (2018).

Table D.4: MicroNuclear LLC MsNB Microreactor Design

Parameter	Conceptual Design Value
Micro-Scale Nuclear Battery Reactor Concept	**Molten Salt Nuclear Battery (2019)**
Reactor module type (e.g., H2O-cooled-Thermal-Rx)	Molten Salt Reactor
Reactor module design life (yrs)	10
Reactor module design capacity factor	Not Available
Thermal output of module (MWth)	10-30MWth
Electrical output of module (MWe)	10MWe
Allowable power ramp up/down (%/min)	Not Available
Reactor coolant	FLiBe – Dissolved UF4
Power conversion system	Heat Pipe to Helium Brayton Cycle
Module transport plans (and fuel)	Cask
Switchyard interconnection requirements	Not Available
Maximum module height (meters)	Not Available
Module exclusion area boundary (sq. meters)	Not Available
Total module area (if different)	9 m2
Above ground exposure (above, at-grade, below grade)	Not Available
Resiliency features (e.g., black-start, cyber-security)	No Pumps/Valves
Stored energy of core/primary system (T, P, V)	Not Available
Ultimate heat sink (air or water)	Not Available
Multi-module planned siting plan	Not Available
Fuel type	UF4 (Dissolved in Salt)
Fissile enrichment (% fissile fuel)	20% Enriched, 5% fuel loading in salt
Refueling period (# full-power-yrs)	10
Refueling requirements (on-site, cartridge core…)	Not Available
Decommissioning requirement	Not Available
Required on-site personnel per module	Not Available
Personnel details (operations, maintenance, security)	Not Available
Control system autonomy vs. required operator actions	Not Available
Estimated overnight capital cost range ($/kWe)	Not Available
Estimated fuel cost range ($/MWh)	Not Available
Estimate deployment schedule	Not Available

Public Information:

- https://gain.inl.gov/SiteAssets/Micro-reactorWorkshopPresentations/Presentations/14-Marotta-MsNBMRWorkshop_June2019.pdf

Table D.5: NuScale LWR Microreactor Design

Parameter	Conceptual Design Value
NuScale LWR Reactor Concept	
Reactor module type (e.g., H2O-cooled-Thermal)	Light water-Thermal-Rx
Reactor module design life (yrs)	60
Reactor module design capacity factor	95%
Thermal output of module (MWth)	40-160
Electrical output of module (MWe)	10 - 50
Allowable power ramp up/down (%/min)	Up 3%/min; Down 10%/min
Reactor coolant	Light water
Power conversion system	Steam turbine generator
Module transport plans (and fuel)	Fuel and module transported separate
Switchyard interconnection requirements	None
Maximum module height (meters)	23
Module exclusion area boundary (sq. meters)	Site boundary
Total module area (if different)	Not available
Above ground exposure (above, at-grade, below grade)	Power Module: Below-grade, Reactor Building/Housing: Above-grade
Resiliency features (e.g., black-start, coping-time, cyber-security)	Black-start, protection system resilient to cyber-attacks, no offsite power required
Stored energy of core/primary system (T, P, V)	Not public
Ultimate heat sink (air or water)	Water
Multi-module planned siting plan	Not specified
Fuel type	UO_2 Ceramic or Lightbridge Zr-U alloy
Fissile enrichment (% fissile fuel)	≤ 4.95 weight % ^{235}U for UO_2 ceramic or ≤ 19.75 weight % ^{235}U for Lightbridge
Refueling period (# full-power-yrs)	6 to 10 years
Refueling requirements (on-site, cartridge core…)	On-site
Decommissioning requirement	Not available
Required on-site personnel per module	Not available
Personnel details (operations, maintenance, security)	Not available
Control system autonomy vs. required operator actions	Passive safety control systems require no operator action
Estimate deployment schedule	≤ 3years
Estimated overnight capital cost ($/kWe)	Not public
Estimated fuel cost range ($/MWh)	Not public

Table D.6: Urenco's U-Battery Microreactor

Parameter	Conceptual Design Value
U-Battery Reactor Concept	
Reactor module type (e.g., gas-cooled-Thermal-Rx)	Gas cooled (helium: primary circuit and nitrogen: secondary circuit
Reactor module design life (yrs)	Not available
Reactor module design capacity factor	Not available
Thermal output of module (MWth)	10 & 20
Electrical output of module (MWe)	4
Allowable power ramp up/down (%/min)	Not available
Reactor coolant	Helium and nitrogen
Power conversion system	Brayton Cycle
Module transport plans (and fuel)	Transport by rail or sea.
Switchyard interconnection requirements	Not available
Maximum module height (meters)	Not available
Module exclusion area boundary (sq. meters)	Not available
Total module area (if different)	Not available
Above ground exposure (above, at-grade, below grade)	Can be adapted to meet local needs (construction can be above or below ground); no specs
Resiliency features (e.g., black-start, cyber-sec.)	Not available
Stored energy of core/primary system (based on T, P, V)	Not available
Ultimate heat sink (air or water)	Not available
Multi-module planned siting plan	Not available
Fuel type	TRISO-fuel; thorium possible
Fissile enrichment (% fissile fuel)	17% for 20MWth case 20% for 10 MWth
Refueling period (# full-power-yrs)	10years (20 MWth)
Refueling requirements (on-site, cartridge core…)	Not available
Decommissioning requirement	Not available
Required on-site personnel per module	Not available
Personnel breakdown (operations, maintenance, security)	Not available
Control system autonomy vs. required operator actions	Not available
Estimated overnight capital cost range ($/kWe)	Not public
Estimated fuel cost range ($/MWh)	12million euros for the 20 MWth

Public Information:

- Ming.D, Kloosterman.J.L, Kooijman.T, Linssen.R et al. Design of a U-Battery. P12. https://www.u-battery.com/_/uploads/AExecSummary.pdf

Table D.7: Ultra-Safe Nuclear Corporation Micro Modular Reactor

Parameter	Conceptual Design Value
Ultra-Safe Nuclear Battery Reactor Concept	***MMR - REM***
Reactor module type (e.g., H2O-cooled-Thermal-Rx)	Gas cooled - Thermal spectrum
Reactor module design life (yrs)	20
Reactor module design capacity factor	95%
Thermal output of module (MWth)	15
Electrical output of module (MWe)	5
Allowable power ramp up/down (%/min)	10%/min
Reactor coolant	Helium
Power conversion system	Molten Salt intermediate to Rankine
Module transport plans (and fuel)	Train/Truck/Barge/Plane
Switchyard interconnection requirements	Not Available
Maximum module height (meters)	Largest Plant Module: 3.6m Plant Building Above Ground Height: 7.2m
Module exclusion area boundary (sq. meters)	6400 m2
Total module area (if different)	800 m2
Above ground exposure (at-grade, below grade)	Below grade
Resiliency features (e.g., black-start, coping-time, cyber-security)	Passive safety systems only for 2 weeks Reactor is isolated from load via molten salt loop
Stored energy of core/primary system (T, P, V)	60 GJ (17 MWh)
Ultimate heat sink (air or water)	Air
Multi-module planned siting plan	1 or more reactors at a plant share common salt heat storage and adjacent plant facilities
Fuel type	FCM containing UO2
Fissile enrichment (% fissile fuel)	12-13%
Refueling period (# full-power-yrs)	Fueled for Life
Refueling requirements (on-site, cartridge core)	None
Decommissioning requirement	6 mo cooldown; No processing required - fuel in a geologically stable form
Required on-site personnel per module	4 per shift
Personnel breakdown (operations, maintenance, security)	2 Operators,1 Security Guard 1 Maintenance Worker
Control system autonomy vs. required operator actions	No safety actions from operator Reactor is fully autonomous
Estimate deployment schedule	6 months on site (post-site preparation)
Estimated overnight capital cost range ($/kWe)	15.7k/kWe (dual reactor configuration)
Estimated fuel cost range ($/MWh)	$25/MWh

Table D.8: X-Energy XE-RRM Microreactor Design

Parameter	Conceptual Design Value
XE-RRM Reactor Concept	
Reactor module type (e.g., H2O-cooled-Thermal-Rx)	HTGR
Reactor module design life (yrs)	~40yrs
Reactor module design capacity factor	90%
Thermal output of module (MWth)	20 MWth
Electrical output of module (MWe)	7.4 MWe
Allowable power ramp up/down (%/min)	Not available
Reactor coolant	Helium
Power conversion system	Rankine Cycle
Module transport plans (and fuel)	Road or rail
Switchyard interconnection requirements	~18m
Maximum module height (meters)	N/A
Module exclusion area boundary (sq. meters)	N/A
Total module area (if different)	N/A
Above ground exposure (above, at-grade, below grade)	Mostly sub grade but PCU building above grade
Resiliency features (e.g., black-start, coping-time, cyber-security)	Not Available
Stored energy of core/primary system (based on T, P, V)	Low pressure heat pipes
Ultimate heat sink (air or water)	water
Multi-module planned siting plan	Multiple units control room
Fuel type	UCO TRISO fuel
Fissile enrichment (% fissile fuel)	19.7 wt%
Refueling period (# full-power-yrs)	Not specified
Refueling requirements (on-site, cartridge core…)	On site refueling acceptable
Decommissioning requirement	Not specified
Required on-site personnel per module	Not specified
Personnel breakdown (operations, maintenance, security)	Not specified
Control system autonomy vs. required operator actions	Semi-autonomous
Estimated overnight capital cost range ($/kWe)	$140-200/MWh
Estimated fuel cost range ($/MWh)	Comparable with diesel cost
Estimate deployment schedule	On-site installed 3-6 months

Appendix E
Microgrids

Introduction

In our study we examine the capability of a microreactor to provide on-site secure power for critical loads at a government installation. Since a "grid-connected" microreactor (or any on-site generator) must operate, at least some of the time, connected to an external electrical grid, we discuss some of the characteristics of the grid relevant to microreactor deployment. This section also considers the impetus and conditions for connecting microreactors within **microgrids**[1] and the costs and benefits of doing so.

Large, interconnected grids (the 'Grid') for reliability and economic benefit

One of the benefits of large, interconnected electricity grids is the ability to share generation resources across vast regions of the continent for both reliability and economic purposes. For example, if a generator in Louisiana were to suddenly trip offline, generation as far away as Manitoba provides immediate replacement power; abundant low-cost hydro-generation on the Columbia river in the Pacific Northwest replaces more expensive coal and gas fired generation in the desert southwest during spring water run-off as well as current light water reactors supplies baseload power to the Pacific Northwest during the salmon spawning season. The interconnected grid enables the sharing of energy and reserves between areas so that the interconnected pool of generation resources can maintain reliable operation at no greater cost than if each area was self-sufficient.

Electrical generation connected to the Grid must continuously balance power supply with demand while maintaining voltage profiles and system frequency. If the voltage or frequency deviates from design specifications, loads such as motors, which make-up most of electrical demand, can operate inadequately and fail. In order to assure that typical occurrences, such as the forced outage of a generator or variations in wind and solar generation output, do not even temporarily disrupt the balance, a subset of generation must be available to provide reserve services across various time frames. For instance, there must always be some generators dispatched to loading points below maximum output, so that those units can increase power output if there is a net generation shortfall. Similarly, there must be other units dispatched above their minimum outputs so that these units can reduce power in response to a net generation surplus. A subset of generation must be capable of responding to frequency deviations instantly while other sets of generation must be tracking the more gradual minute-to-minute fluctuations. Still other sets of generation must be capable of providing replacement power in ten or thirty minutes after an event. At any point in time, which units should be providing which services depends upon the local conditions across the grid. Thermal generation efficiency changes with ambient temperature while the cost of fuel varies due to the costs and constraints on transport (natural gas) or storage (diesel or liquefied natural gas). Which generation units to have online, and the power output each should be set to, requires consideration and forecasting of a myriad of factors including the demand for electricity over time, weather patterns, and the physical and economic characteristics of the pool of generation

[1] "A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid." – IEEE 2013<<cite publication>>

resources. The successful operation of the interconnection necessitates agreements and processes for communicating information between all the entities responsible for and dependent upon the Grid. The effective utilization of a large interconnect Grid thus requires coordination between entities including regional system operators, utility companies, states, and even countries (U.S. and Canada).

It should be noted that in areas such as remote, congested, weather challenged, or otherwise differentiated grid interconnects, on-site generators within a microgrid can alleviate a number of challenges and provide added resilience. Challenging conditions that some high reliability installations encounter with grid interconnects, such as low voltage ride through, poor frequency response, unstable protection and control have already been effectively accommodated by microgrids combined with robust distributed local on-site generation. This is the focus being investigated here with microreactors.

Transmission and distribution failures

The interconnected grid mitigates the consequences of generator outages by increasing the pool of generation available to provide replacement power. However, electric system reliability is affected by transmission and distribution outages in addition to generation outages. The failure of the transmission system in the Northeastern United States and Ontario Canada in August of 2003 is estimated to have resulted in economic losses exceeding 4 billion dollars. Devastation to the distribution systems is one of the most costly and disruptive impacts from hurricanes. Failures of the local distribution system are not alleviated by generation connected elsewhere on the transmission system, because the distribution system does not connect the remote generation to the local load. However, local distribution outages are mitigated by local distribution-connected generation, such as back-up generation that can power a building disconnected from the grid.

Events such as the widespread blackout of August 2003, and devastating hurricanes such as Katrina, Sandy and Maria, have motivated the concept of **microgrids** – portions of the grid that are self-sufficient, at least for some duration of time, and that can connect to or disconnect from the grid whenever necessary or economical. In order to meet the connected electrical load when isolated from the grid, microgrids must include local on-site power generation and/or energy storage.

Microgrids

The motivation for microgrids is **resiliency**. While the microgrid is interconnected to the larger interconnected Grid, the demand within the microgrid enjoys the same reliability benefit of demand elsewhere in the system. That is, the supply of electricity to the microgrid's load is mostly immune to outages and disturbances of either remote or local generation and supply contingencies across the interconnection. However, the microgrid is also resilient to transmission and local distribution outages.

Considering the benefits of the large Grid touted in the previous sections, one should wonder how well a microgrid could replace the services of the Grid while operating disconnected from the Grid. The answer is unique for each microgrid and is part of the design of the microgrid. Indeed, one could consider a microgrid as a special case of the Grid on a very small scale. Supply still must balance demand virtually instantaneously and be resilient to expected disturbances of both load and generation. Even the demand in a small office building changes over time as equipment is energized and deenergized. The Grid has surplus generation for reserves, and generation to provide load following and regulation, a microgrid must be able to provide the same functions when disconnected from the main grid.

The total demand of a microgrid, from a few MWe up to a hundred MWe, is less than one-hundred-thousandth of the interconnected Grid. While the interconnected Grid must accommodate a comprehensive range of load possibilities over extended time frames (decades), the characteristics of the demand within a microgrid can be known very well. The supply (generation and storage) resources on the microgrid are tailored to the demand characteristics on the microgrid, which can be anticipated with great accuracy due to the smaller size, number, and variety of loads compared to on the entire interconnection.

The greater the redundancy and diversity of individual generators and the surplus power production capability on the microgrid, the greater the ability of the microgrid to withstand separation from the grid and the outage of any source of supply within the microgrid. Since the capacity of generation connected to the microgrid might be less than the total load connected to the microgrid, microgrids generally require the ability to shed loads.

In particular a few key attributes of both the microreactor and the microgrid support each other's strength while diminishing their weaknesses. Microreactor technologies as evaluated in this study have relatively high "grid inertia" as compared to other distributed energy sources and therefore promote the proper autonomous connection, disconnection, and load adjustment thus enabling better resiliency features for the microgrid.

Microgrid costs

For the purposes of this project, we will define microgrid per the IEEE definition: "A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid."

Before the IEEE definition was published in 2013 many of the early pioneers of "microgrids" (such as Dr. Robert Lasseter of the University of Wisconsin-Madison) more precisely defined other microgrid capabilities such as smooth switching between grid connection to stand alone island operation, local optimizing controller, and autonomous power control operation based upon only relying on the local condition of the grid dynamics.

Table E.1: Classification of Microgrid Complexity

Level	Definition	Range of cost ($ millions)	Mean ($ in millions)
1	Stand-alone generator	0.93 - 2.86	1.98
2	Distribution automation, Distributed generation (1 or more units)	2.18 - 4.87	3.46
3	Controller, thermal assets, renewables, energy storage.	1.94 - 3.82	3.05
4	Controller, Load management	3.73 - 5.14	4.44

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In Figure it can be seen that in today's world of microgrids, current systems have progressed to a state where there are distinct classifications. When almost any coordinated local generation, storage and distribution system may be called a microgrid we provide an example microgrid that can best match the required advantages of microreactor on-site generation.

Based on this premise we will include flexible options in our example microgrid that provides a sequence of possible benefits vs a range of estimated cost based on our experience as well as a series of respected studies. These benefits will include smooth transition island and connected operation, local optimizing energy control including combined heat and power control optimization and fail-safe autonomous power flow control operating modes.

In Table and E.3 below we summarize some cost ranges for microgrid installation that contain varying degrees of the previously stated functionality[cxii]. Note that the IQR is defined as Interquartile range. This mean point between the 25th and 75th percentiles or the difference between the upper and lower quartile. This statistical approach is utilized because of the wide range of costs in the related case examples that have many varying factors of function and varying means of financing the entire system installation.

Table E.2: Budgetary Costs from Microgrid Case Studies ($/MW)

Market Segment	Interquartile Range (IQR)	Mean
Campus/Institutional	$4,936,109–$2,472,849	$3,338,666
Commercial/Industrial	$5,353,825–$3,399,162	$4,079,428
Community	$3,334,788–$1,430,805	$2,119,908
Utility	$3,219,804-$2,323,800	$2,548,080

Table E.3: Microgrid Costs by Microgrid Levels ($/MW)

Market Segment	Interquartile Range (IQR)	Mean
Level 1	$2,856,775-$931,485	$1,981,800
Level 2	$4,870,648-$2,178,975	$3,462,685
Level 3	$3,820,975-$1,940,507	$3,053,979
Level 4	$5,142,510-$3,727,321	$4,436,563
Level 5	$3,700,938-$2,920,014	$3,310,476

The capital cost ranges of the various other on-site generation technologies must also be included (see Figure E.1 and Figure E.2 below)[cxiii] as a check against the relative scale of the on-site generation combined with microgrid additional costs. These would be deemed applicable specifically as regards utilization of a microgrid interconnect and control as a means to provide the largest benefits from a microreactor installation.

These capital costs as a means of relative comparison show both a $/kW and $/kWh range of expenditures based on the 2017 Lazard study of multiple projects. It becomes clear that the natural gas peaking and standalone behind the meter options for those facility with access to the Natural Gas Grid provide the best pure cost option at ranges of approximately $700 to $1300 $/kW installed and there for deliver a Levelized Cost of Energy $40 to $ 70 $/MWh.

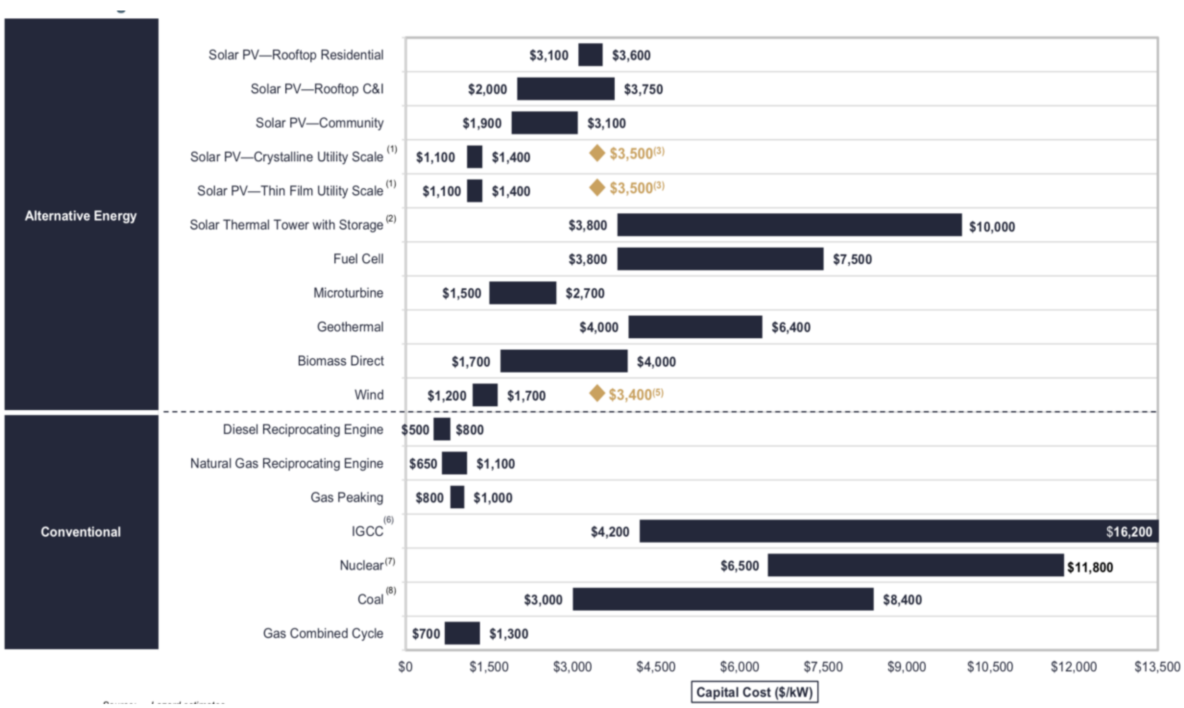

Figure E.1: Capital Cost Comparison in $/kWe (Estimates from Lazard [2])

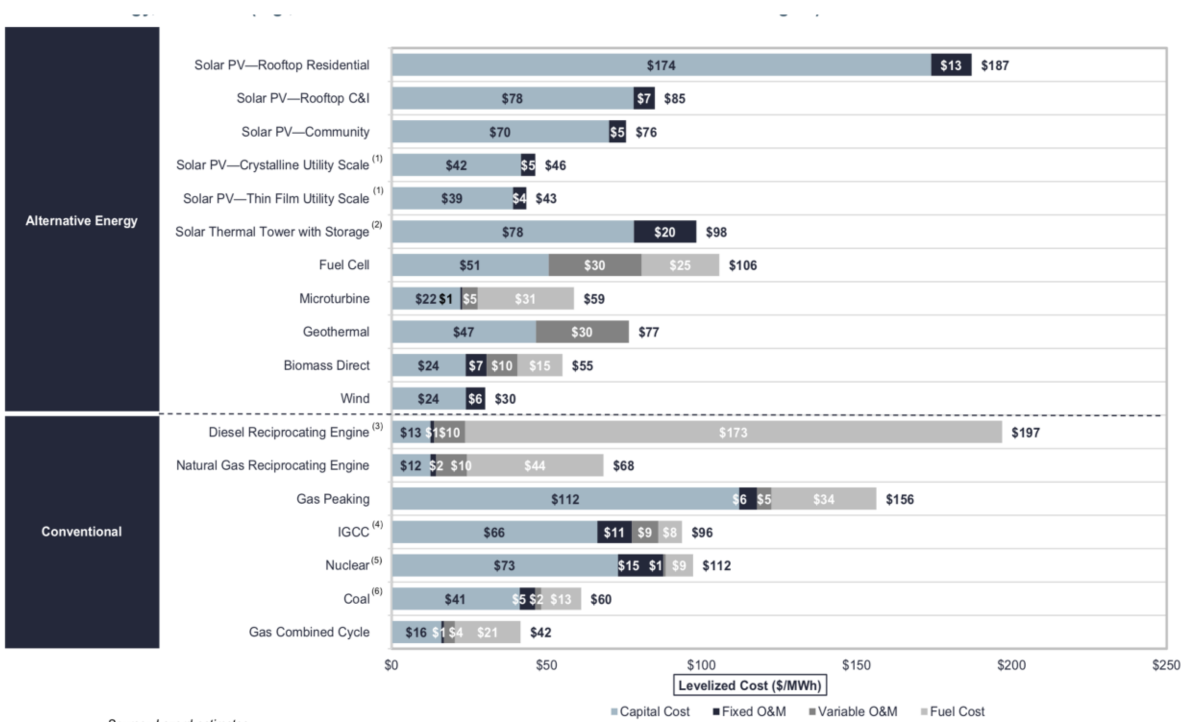

Figure E.2: Levelized Cost of Electricity in $/MWh (Estimates from Lazard [2])

Example Schematic: Microgrid application to a Microreactor

The schematic diagram Figure E.3 is a representation of an average configuration of a microreactor with combined heat and power integrated into a select facility by use of a microgrid interconnect. A number of salient qualities we assume to be either fundamental or optional to the microgrid shown:

- Smart Switch at the point of common coupling that enables disconnection and reconnection to a utility grid or other local shared power grid.
- Combined heat and power capability that is considered part of the power plant design and cost but is controlled and coordinated by microgrid controller.
- Trim boiler for optional application where thermal production has to be boosted when electrical production does not produce sufficient heat.
- Optional process heater (steam generator) for production of additional heat from excess electrical capacity.
- Additional fuel (fossil and chemical) powered thermal to electrical gen set.
- Optional solar PV-Battery Grid Tie inverter subsystem(s)

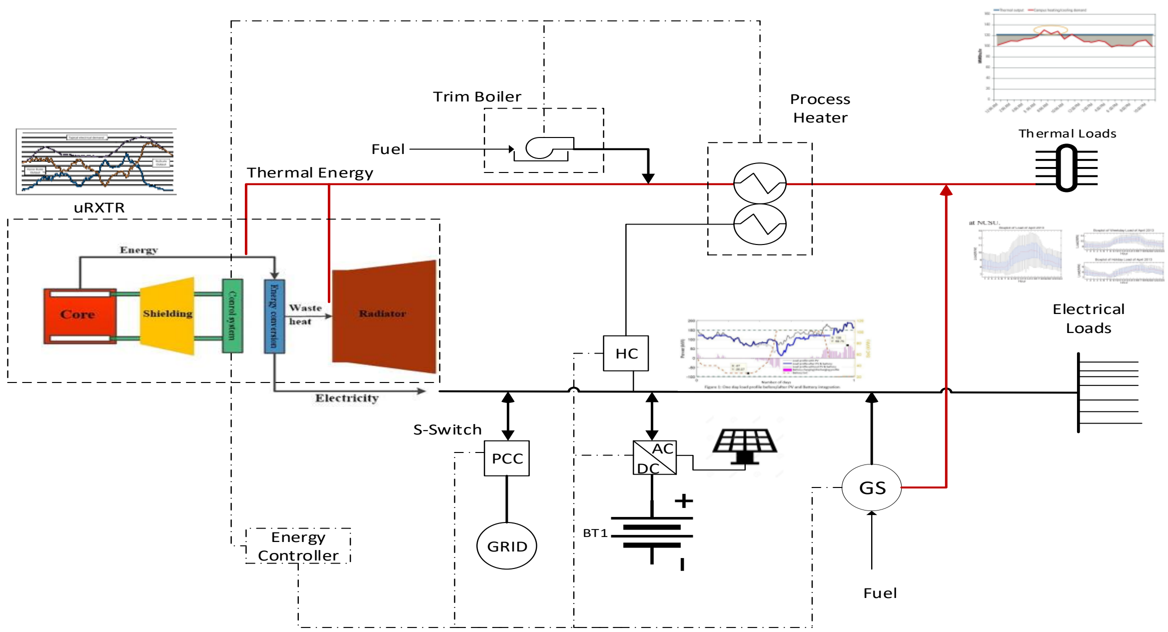

Figure E.3: Schematic diagram of a microreactor integrated into microgrid

Qualitative and Quantitative Comparison of Microreactor Installation with Microgrid types

In Table it can see seen that we have started with a qualitative of the relative benefits (functions) that a microgrid would enable when combined with traditional DER's and with different types of microreactors. These qualitative comparisons are derived from a group of references that were published between 2016 and 2019[cxiv, cxv,cxvi] . The purpose of this comparison is to give a relative assessment of fit between a range of very new microreactor designs and various versions of microgrid capabilities.

Table E.4: Pugh Matrix of Relative Benefits of Local Generation, Storage on a Microgrid

Tech	Capital Cost	Operating Cost	Local Freq. and Voltage Control	High Pulse Power	Resiliency beyond 4 nines	Long Duration Standalone Operation	Perfect Power	Energy Density for at scale Mobile and Emerg.	Bump less Islanding/ Local Reconfig.
uRXTR-1	---------	++	+++++	++++	+++	++++++	+++	++	++
uRXTR-2	------	+++	++	+++++	+++++	+++++	++++		++
uRXTR-3	-----	++++	++	++	++++++	++++	+++++	+++++	++
NG CC	+++	++	+	--	++	--	+	+-	++
Diesel Recip.	+++	+-	-	-	++	--	-	+-	+
Jet Deriv. TurbineCC	+-	+	+	+	--	--	+	-	+
PV Battery	--	++++	++	-	+	++	+++	--	+++

Table E.5 below is composite of a number microgrid cost estimates taken of references as well as review of a number of electrical distribution projects that have been executed at the University of Wisconsin - Madison and University of Wisconsin -Milwaukee campuses.

Table E.5: Quantitative matrix of cost estimate breakdown for applicable microgrids

Microgrid Sub-system	Type I ($/kW)	Type II ($/kW)	Type III ($/kW)	Cost Trajectory (CAGR)
Smart Switch	350	570	1,250	-12%
Distribution Sub-Station	250	250	250	-9%
Power Cabling	170	170	170	-3%
Power Flow and Protection	200	200	250	-7%
Grid Tie Inverters	140	150	200	-11%
Control System	250	280	450	-11%
u-Grid Specific Total | Median	**1,360**	**1,620**	**$2,570**	**-10%**

Definitions: Type I = Level 1, 2 Capabilities; Type II =Level 3,4; Capabilities; Type III = Level 5,6

Conclusions

The application of microgrids as a primary power distribution and grid interface for installations that would benefit from local on-site generation and storage has been shown by previous studies to be highly dependent on the primary performance/cost trade-offs that are deemed to be of critical importance. If one desires a highly robust islanding and reconnection to the grid, local reconfiguration of generation and load power flow and control, and seamless additions of new distributed energy resources (renewables, storage, etc.) then the additional costs over traditional electrical distributions systems are well worth the investment.

Likewise, if microreactor characteristics that drive its selection as a local energy (and storage) power resource can be further amplified by the addition of a microgrid distribution system it is highly likely that a representative cost/benefit life cycle analysis would favor the combination of these two technologies.

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Appendix F
Economic Analysis Input Summary

System	Low	Med	High
Electricity rate (utility)	$0.06/kWh	$0.06/kWh	$0.06/kWh
Total power needs	4 MW	4 MW	4 MW
Critical power needs	2 MW	2 MW	2 MW
Peak power needs	4 MW	4 MW	4 MW
Assumed duration of outage	7 days	7 days	7 days
Interest rate for borrowing		2% - 10%	

Table F.1: Microreactor Economic Inputs

Economic Analysis Cost Input Summary =

Microreactor	Low	Median	High	Reference
Capital Cost ($/kWe)	10,000	15,000	20,000	NEI 2019 (FOAK) [1]
	4,000	8,300	15,000	NEI 2019 (NOAK)
	6,500		11,800	Lazard 2017 [2]
Capacity Factor	0.45		0.95	NEI 2019
Plant Life (yrs)	20	40	60	NEI 2019
Fixed O&M Costs ($/kWe)	250	350	450	NEI 109
	100		150	Lazard 2017
Fuel Cost ($/MWh) (variable cost is small)	6	10	14	NEI 2019
		9		Lazard 2017
Core Fuel Life (yrs)	5	10	20	NEI 2019
Refurb. Cost ($M/refuel)	13	20	27	NEI 2019
Decommissioning ($/MWh)	3	5	7	NEI 2019

Sensitivity Calculation Range

Microreactor	Low	Median	High	Reference
Capital Cost ($/kWe)	4,000	12,000	20,000	Combined range [3]
Capacity Factor	0.98	0.98	0.98	Target range [4]
Plant Life (yrs)	20	40	60	NEI 2019
Fixed O&M Costs ($/kWe)	100	250	450	Combined range [3]
Fuel Cost ($/MWh)	12	20	28	Combined range [5]
Refurb. Cost ($M/refuel)	*Included in fuel cost above*			
Decommissioning ($/MWh)	3	5	7	NEI 2019 range

[1] M. Nichols et al, Cost Competitiveness of Microreactors for Remote Markets, NEI, 2019.
[2] Lazard - Levelized Cost of Energy Analysis, Version 11, Nov. 2017.
[3] Capital cost range represents the combined range of FOAK and NOAK of cost estimates from Ref. [1]
[4] The capacity factor range is a performance target that is assumed to be similar for each technology.
[5] Operation cost range represents the broad combined range of two references [1] and [2]
[6] Fuel cost range from Ref. [1] is doubled to account for associated fuel transport and refurbishments.

Table F.2: Diesel Generator Economic Inputs

Economic Analysis Cost Input Summary

Diesel Generator	Low	Median	High	Reference
Capital Cost ($/kWe)	800		1100	NREL TR-1 [1]
	500		800	NREL TR-2 [2]
	500		800	Lazard 2017 [3]
	925		1475	EPA 2015 [4]
Capacity Factor	0.85		0.98	Consistent range
Plant Life (yrs)	5		10	EPA 2015
Fixed O&M Costs ($/kWe)	23		32	NREL TR-1
	35		35	NREL TR-2
	8	10	15	Lazard 2017
Variable O&M Cost ($/MWh)	10		15	Lazard 217
Fuel Cost ($/mmBTU)	19.2	19.5	19.9	NREL TR-2
		18.2		Lazard 2017
	20		30	EIA 2019 [5]
Thermal Efficiency	32		40	EPA 2015

Sensitivity Calculation Range

Diesel Generator	Low	Median	High	Reference
Capital Cost ($/kWe)	500	800	1100	Combined range [6]
Capacity Factor	0.98	0.98	0.98	Target range
Plant Life (yrs)	5	8	10	EPA 2015
Fixed O&M Costs ($/kWe)	20	30	35	Combined range [7]
Thermal Efficiency	32	37	40	EPA 2015
Fuel Cost ($/mmBTU)	20	25	30	EIA 2019
Fuel Cost ($/MWh)	213 (0.32)	230 (0.37)	256 (0.4)	(w/ thermal efficiency)

[1] J. Kurtz et al, Backup Power Costs..., Tech. Rpt, NREL/TP-5400-60732, Sept. 2014.
[2] S. Ericson et al, A Comparison of Fuel Choice for Backup Generators, Tech. Rpt, NREL/TP-6A50, Mar. 2019
[3] Lazard - Levelized Cost of Energy Analysis, Version 11, Nov. 2017.
[4] EPA Catalog CHP Technologies: Section 2 – Reciprocating IC Engines, March 2015 (with emission controls)
[5] EIA - https://www.eia.gov/petroleum/gasdiesel/ (Note: Diesel energy content ~ 0.14 mmBTU/gal)
[6] Capital cost range represents the combined range of cost data from Ref. [1-4]
[7] Operations cost range represents the combined range of cost data from Ref. [2-3]

Table F.3: Natural Gas Generator Economic Inputs

Economic Analysis Cost Input Summary

Natural Gas Generator	Low	Median	High	Reference
Capital Cost ($/kWe)	900		1000	NREL ATB [1]
	800		1100	Lazard 2017 [2]
	1620		1975	EPA 2015 [3]
		1084		EIA 2019 [9]
Capacity Factor	0.85		0.98	Consistent range
Plant Life (yrs)	5		10	EPA 2015
Fixed O&M Costs ($/kWe)	10		12	NREL ATB
	6		20	Lazard 2017
Variable O&M Cost ($/MWh)	5		10	Lazard 217
Fuel Cost ($/mmBTU)	2.9	3.5	4.3	EIA AEO [4]
		3.45		Lazard 2017
Thermal Efficiency	35		42	Lazard 2017
LNG Cost ($/mmBTU)	5		7	EIA (LNG) [5]

Sensitivity Calculation Range

Natural Gas Generator	Low	Median	High	Reference
Capital Cost ($/kWe)	800	1100	2000	Combined range [6]
Capacity Factor	0.98	0.98	0.98	Target range
Plant Life (yrs)	5	8	10	EPA 2015
Fixed O&M Costs ($/kWe)	10	20	30	Combined range [7]
Thermal Efficiency	35	39	42	Lazard 2017
Fuel Cost ($/mmBTU)	2.9	3.6	4.3	EIA AEO
Fuel Cost ($/MWh)	28 (0.35)	31.5 (0.39)	35 (0.42)	(w/ thermal efficiency)
LNG Cost ($/mmBTU)	5	7.5	10	EIA values [8]
LNG Cost ($/MWh)	49	65.4	81	(w/ thermal efficiency)

[1] NREL Advanced Technology Baseline - https://atb.nrel.gov/electricity/2018/index.html?t=cg
[2] Lazard - Levelized Cost of Energy Analysis, Version 11, Nov. 2017.
[3] EPA Catalog CHP Technologies: Section 3 – Combustion Turbines, March 2015 (w emission controls)
[4] EIA AEO - https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf
[5] EIA - https://www.eia.gov/dnav/ng/hist/n9133us3M.htm
[6] Capital cost range represents the combined range of cost data from Ref. [1-3]
[7] Operations cost range represents the combined range of cost data from Ref. [1-2]
[8] Fuel cost range based on EIA data for low values with high value based on historical data.
[9] EIA, 2019: https://www.eia.gov/analysis/studies/powerplants/capitalcost/xls/table2.xlsx

Table F.4: Renewable Energy Economic Inputs

Economic Analysis Cost Input Summary

Solar PV	Low	Median	High	Reference
Capital Cost ($/kWe)	750			IRENA [1]
	1660		2300	NREL ATB [2]
	1260		1700	Lazard 2017 [3]
			2800	HOMER [4]
		1313		EIA 2019 [6]
Lifetime (yrs)	20		25	NREL HOMER [5]
Fixed O&M Costs ($/kWe)	12		16	NREL ATB
	10		14	Lazard 2017
Wind Turbine	**Low**	**Median**	**High**	**Reference**
Capital Cost ($/kWe)	1680			IRENA [1]
	1800		2400	NREL ATB [2]
	1200		1700	Lazard 2017 [3]
		2000		HOMER [4]
		1667		EIA 2019 [6]
Lifetime (yrs)		20		NREL HOMER [5]
Fixed O&M Costs ($/kWe)		51		NREL ATB
	29		40	Lazard 2017
Li Ion Battery	**Low**	**Median**	**High**	**Reference**
Capital Cost ($/kWh)		580		IRENA [1]
	515			Lazard 2017 [3]
		550		HOMER [4]
Lifetime (yrs)	10		15	HOMER
Fixed O&M Costs ($/kWh)		37		NREL ATB [2]
		10		HOMER

Sensitivity Calculation Range

Solar PV	Low	Median	High	Reference
Capital Cost† ($/kWe)	750	1775	2800	Combined range
Lifetime (yrs)	20		25	NREL HOMER [5]
Fixed O&M Costs ($/kWe)	10	15	20	Combined range
Wind Turbine	**Low**	**Median**	**High**	**Reference**
Capital Cost ($/kWe)	1200	1800	2400	Combined range
Lifetime (yrs)	20		20	HOMER [4]
Fixed O&M Costs ($/kWe)	29	40	51	Combined range
Li Ion Battery	**Low**	**Median**	**High**	**Reference**
Capital Cost ($/kWh)	515	550	580	Combined range
Lifetime (yrs)	10		15	HOMER
Fixed O&M Costs ($/kW)	10	18	37	Combined range

† Note: Includes cost of DC/AC converter with estimates of 160-300 $/kWe (IRENA)

[1] IRENA https://www.irena.org/Statistics/View-Data-by-Topic/Costs/Solar-Costs
[2] NREL-ATB https://atb.nrel.gov/electricity/2018/index.html?t=in
[3] Lazard - Levelized Cost of Energy Analysis, Version 11, Nov. 2017.
[4] HOMER Software - https://www.homerenergy.com/
[5] HOMER Model based on 1%/yr degradation (NREL/CP-5200-54109 July 2012)
[6] EIA, 2019: https://www.eia.gov/analysis/studies/powerplants/capitalcost/xls/table2.xlsx

Appendix G
Modeling 4 MWe renewables generators – Madison vs Phoenix

Off-Grid Resilient Scenario

In this scenario, the 4 MWe supports all site needs (satisfies peak power requirement) The site needs no power from the utility.

As an example of how the results depend on the details of the weather, we compare the capacity needed to supply 4 MWe in Madison, WI, and compared that to the capacity needed for Phoenix AZ. The following assumes a discount rate of 2%.

Table G.1: Comparing Average Weather Conditions between Madison, WI, and Phenix, AZ.

Location	Annual Average Weather Condition		
	Solar radiation[1] (kWh/m²/d)	Wind speed[2] (m/s)	Temperature[3] (℃)
Madison	3.96	5.54	8.21
Phoenix	5.52	5.21	18.68

[1] Solar irradiance: National Renewable Energy Lab database. National Solar Radiation Database.
[2] Wind speed: NASA Surface meteorology and Solar Energy database. Air temperature, monthly averaged values over 22 year period (July 1983 – June 2005).
[3] Temperature: NASA Surface meteorology and Solar Energy database. Wind speed at 50m above the surface of the earth for terrain similar to airports, monthly averaged values over 10 year period (July 1983 – June 1993).

Phoenix enjoys more days of full sunlight than Madison. The effect of the more abundant resource in Phoenix on sizing is partially offset by the higher average temperature, which leads to lower PV panel efficiency. As a result, as shown in the chart below, the optimized solar optimized array in Phoenix would need to be only about 80% of the size of the array for Madison and would need only about 63% of the storage capacity.

The situation is reversed for wind, where Madison experiences more wind than Phoenix. In this case the wind generator in Phoenix would need to be 34% larger than in Madison, and the associated storage would need to be 16% greater.

Table G.2: System Configurations in Different Renewable Energy Scenarios

	Madison	Phoenix
Solar+Battery System Configuration		
Capacity of solar generator	133 MWe	105 MWe
Energy storage - batteries	273 kWh	172 kWh
Wind+Battery System Configuration		
Capacity of wind generator	75 MWe	99 MWe
Energy storage - batteries	330 kWh	386 kWh

The dramatic result is that it takes a large installed capacity to deliver 4 MWe constant power in either of these sites. The reason is shown graphically below for Madison. The charts below show the results of the analysis for 7 days where the renewable resource is limited.

- The upper chart shows the assumed constant demand of 4 MWe over the 7-day period, while the power source(s) vary from zero to spikes at about 35 MWe.
- While the power source practically disappears from Oct 29 to Oct 30, the site is powered by the batteries, and they drain completely.
- During the last three days of the week, the solar cells are providing enough energy both to power the site and to re-charge the batteries.

<u>The need for the large capacity in the renewable generator is due to the fact that there is a disconnect between when the resources is available and when the power is needed.</u>

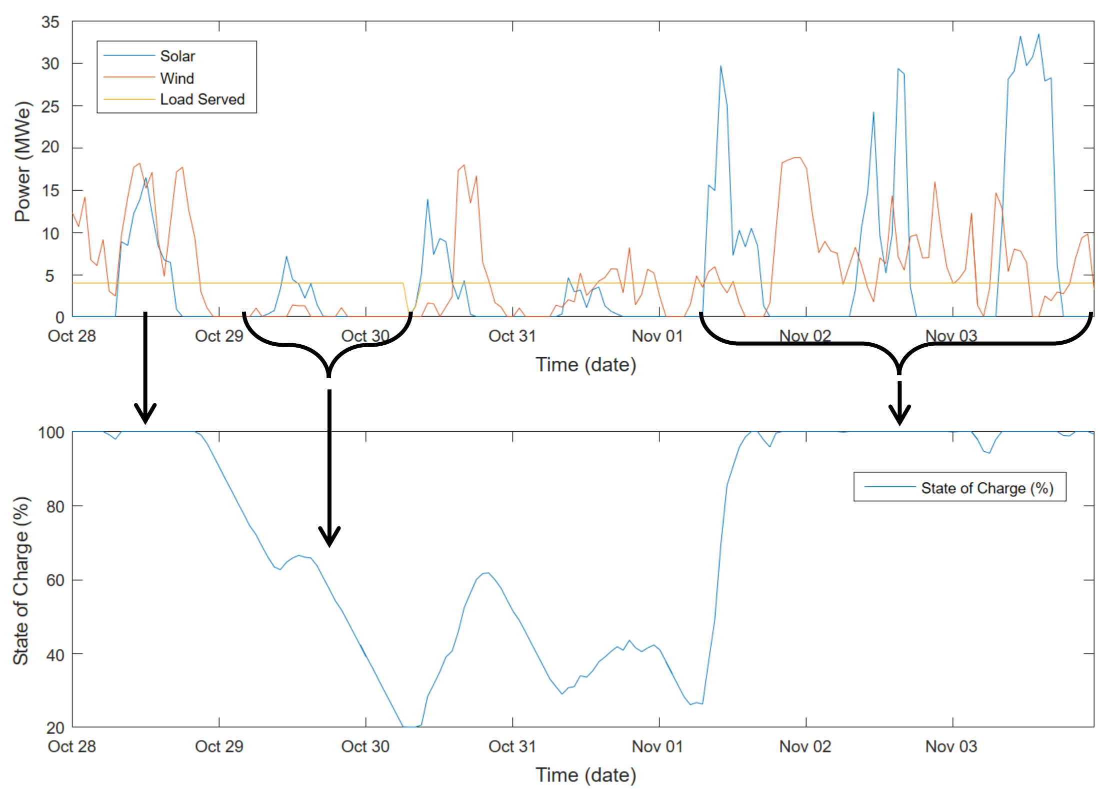

Figure G.1: Detailed Analysis of Battery Usage in Renewable+Battery Case

Note that energy from the battery would be needed to power the site for several entire 24-hour periods. Also note that the source of power for the site has to shift rapidly between the solar array and the batteries as the weather changes.

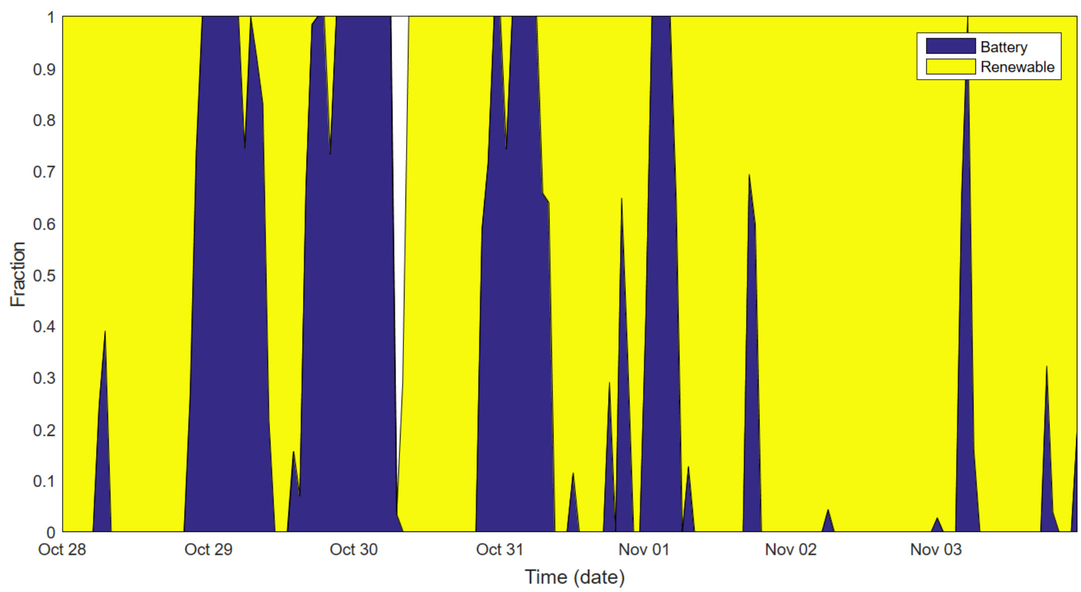

Figure G.2: Battery Charge State over One Week in Renewable Energy Case

Excess energy and "cost"

There are cost implications for this "Optimization" of batteries versus direct renewable power. Because the generator (either solar PV or wind turbine) is assumed to run at full power whenever the resource is available, there are times when generator will be producing electricity even though the batteries are full, and even though the site has no need for the energy being produced during this time. The question arises as to the value of the "excess" energy produced.

Table G.3 below shows the amount of excess energy produced for a system that delivers on a constant demand of 2 MWe. As described above, the weather is assumed to be in Madison WI.

Table G.3: Excess Energy Generation in Different Renewable Cases

In order to produce 2 MWe	**Solar**	**Wind**	**Solar + Wind**	
Generator capacity (MWe)	66	37	17	9
Battery capacity (MWh)	137	166	70	
Excess energy (annual) (GWh)	95.7	63.4	31.5	

- In the case of a facility that is remote or simply off-grid, the site would have no way to sell the energy. With no market for the excess energy, it would have no value.
- In the case of a facility that is connected to the grid, a facility would be using power purchased by the utility as its main source of power. It would then be generating on-site power at a lower level, probably enough to meet its critical power requirements during an outage. In this case, the installation would use the excess energy on-site and reduce the amount of energy that the installation is buying from the utility, so there would be a value to

the excess energy. For example, if the cost of electricity from the utility is $.06/kWh, then the value of the excess energy would be equal to the avoided cost of buying power from the utility.

Note that, from the table above, a solar generator would produce 95.7 GWh of excess energy each year, which would be worth $5.7 million.

Uncertainty in the results from HOMER

We also found a small effect that needs to be explained. The output of the HOMER program predicts an excess energy that changes slightly with changes the assumed discount rate. (Given the capital, or overnight cost of a generator, the discount rate dictates the annual cost of the generator.)

This effect is shown in Table G.4 below, which simply records the output of the program for various assumed discount rates.

Table G.4: System Configuration and Excess Energy as a Function of Discount Rate

Discount Rate	Solar + Wind Capacity (MW)	Battery Storage Capacity (MWh)	Excess Energy (MWh/yr)	Project Net Present Value ($)
2%	52.6	139.5	63,195	209 million
4%	50.4	140.6	60,162	191 million
6%	50.3	139.6	60,053	177 million
8%	50.4	141.7	59,443	166 million
10%	50.6	139.5	60,510	158 million
Average	50.9	140.1	60,673	180 million

This uncertainty comes about because HOMER uses a statistical approach to getting a "best" answer. The difference in each of the calculations the uncertainty in the "real" answer; the variation with interest rate is an artifice of the iterative solution technique used by the HOMER software.

In order to arrive at an estimate of the actual excess energy, we averaged the results from the several runs of the HOMER software. As shown above, the average value is 60.7 GWh. The standard deviation is 1.3 GWh, or 2%.

For the purpose of this report, we consistently use the average value for the excess energy.

Appendix H
A Model of the Resiliency Benefit

This appendix presents a model of the additional resiliency benefit a nuclear generator provides relative to a fossil-fueled generator with a fixed amount of fuel, whether a diesel generator or a natural gas generator with LNG stored on site. In this model, the nuclear generator is grid-connected and always operates, including during a grid outage. The fossil-fueled generator is a backup generator that only operates if there is a grid outage. The key insight is that because purchasing and storing fuel is costly, the nuclear generator will be able to provide backup generation for longer outages. This additional resiliency benefit will depend on the frequency of long outages, the benefit of power during these large outages, and how costly it is to store large amounts of fuel on site.

For simplicity, assume there is no more than one outage per year. The length of this outage in days is drawn from $f(\cdot)$. Backup power allows for some activity to continue during the outage. Let π be the daily benefit from this activity.

First, consider the nuclear generator that is already deployed to operate at a power level equal to the critical power needs of the facility. If a utility outage occurs, this generator can provide backup power at no additional cost. For an outage of v days, πv is the benefit of this backup power (relative to to having no backup power). Thus, the annual benefit from having the nuclear generator for backup power is the following:

$$\int_0^{\bar{X}} \pi v f(v) dv \tag{H.1}$$

where $\bar{X}$ is the maximum possible outage length for the year, and $\int_0^{\bar{X}} f(v)dv = p$, the probability of having a single outage during a year. Note that we assume that the nuclear generator will be able to provide backup power for the entirety of any outage.

Next, consider a fossil-fueled generator with fuel stored on site. While this generator can also provide backup power, its use is constrained by the amount of fuel on hand. The amount of fuel on hand, or equivalently the longest outage the generator can provide backup power for, is a decision the plant-manager must make based on the cost to purchase and store the fuel, as well as the benefit of having backup power and the distribution of outage lengths. Let c be the cost of fuel to run the generator for each day of outage. The total net benefit from having backup power for an outage of v days is $(\pi - c)v$. There is also a cost to storing the fuel that must be paid regardless of whether an outage occurs. Let this cost be $g(x)$ where the marginal cost is increasing in the amount of fuel stored, i.e., $g'(\cdot) \geq 0$. For each year, the expected net benefit of having a backup generator with enough fuel to run for x days is the following:

$$B(x) = B_{v<x} + B_{v>x} - g(x)$$

$$B(x) = \int_0^x (\pi - c)vf(v)dv + \int_x^{\bar{X}} (\pi - c)xf(v)dv - g(x)$$

$$B(x) = \int_0^x (\pi - c)vf(v)dv + (\pi - c)x(p - F(x)) - g(x) \tag{H.2}$$

If the year's outage lasts fewer than x days, the backup generator runs for the duration of the outage. The first term is the expected net benefit from outages that last less than x days. If the outage is longer than x days, the backup generator can only run for x days. The second term is the expected net benefit from having the generator if there is an outage that lasts longer than x days.

The manager chooses the amount of time the backup generator can run for, x, to maximize the net present value over the life of the generator, T years.[cxvii] This calculation also includes the upfront cost of buying the initial fuel, cx.

$$\max_x \quad -cx + \sum_{t=1}^{T} \beta^t \left[\int_0^x (\pi - c) v f(v) dv + (\pi - c) x (p - F(x)) - g(x) \right]$$

where $\beta = 1/(1 + r)$ is the discount factor. The corresponding first order condition is,

$$-c + \sum_{t=1}^{T} \beta^t \big[(\pi - c)\big(p - F(x)\big) - g'(x) \big] = 0 \qquad \text{(H.3)}$$

The marginal cost of increasing the amount of time the backup generator can run for, x, is c upfront plus the incremental storage cost $g'(x)$ that must be paid every year. The marginal benefit is the expected net present value of having the generator run a little longer in case of an outage. This is the net benefit from having the generator run a little longer,($\pi - c$), multiplied by the probability of the outage being long enough to realize this benefit, ($p - F(x)$). Rearranging gives

$$\kappa[(\pi - c)(p - F(x)) - g'(x)] = c$$

where $\kappa = (\beta - \beta^T)/(1 - \beta)$. The optimal length x^* increases in the economic return to backup power, the discount factor, and the likelihood of long outages, while it decreases in the cost of fuel and its storage.

We next calculate the expected annual benefit from the nuclear generator relative to the fossil-fueled generator due to its ability to provide backup power for long outages at no incremental cost. Let x^* be the amount of time the backup generator can run for, implicitly defined by equation H.3. In each year, the expected benefit from having nuclear rather than a fossil-fueled backup generator is equation H.1 less equation H.2 evaluated at x^*:

$$R(x^*) = \underbrace{\pi \left[\int_{x^*}^{\bar{X}} v f(v) dv - x^*(p - F(x^*)) \right]}_{\text{resilience benefit}} + \underbrace{c \left[\int_0^{x^*} v f(v) dv + x^*(p - F(x^*)) \right] - g(x)}_{\text{cost benefit}} \qquad \text{(H.4)}$$

where the resiliency benefit is the expected benefit from operating during outages longer than x^* - outages where the fossil-fueled generator can only operate for x^* days - and the cost benefit is the expected benefit from avoiding the costs of purchasing and storing fuel.

The magnitude of this additional benefit from nuclear will vary based on the cost of fuel and three site-specific factors, specifically:

- the marginal benefit of continued operation,
- the cost of storing fuel on site, and
- the probability of long outages.

Marginal Benefit of continued Operation

The marginal benefit will be largest for sites that place a high value on continued operation, i.e., we would expect this benefit to be higher for a hospital than for a University classroom. For this analysis, we have abstracted from the possibility that this benefit depends on how long it has been since grid power went out. However, it is reasonable to expect the benefit, π, to be a function of time. Consider a facility that only needs backup power to complete a safe shutdown of equipment. The marginal benefit will be very high in the early time until that shutdown has been completed, and then lower thereafter, possible less than the cost of the fuel to remain operational.

Cost of Storing Fuel

When facilities are conducting essential operations, plant-managers with backup generators will respond by storing more fuel on site. Yet, keeping a large amount of fuel on site can be costly, and the marginal cost of storing fuel may be increasing in the quantity stored. For example, safety regulations may be stricter for larger storage tanks, or unused fuel may need to be replaced periodically. Storage costs may also vary based on the cost of land and climate conditions where the site is located.

Distribution of Outage Lengths

Finally, the magnitude of this resiliency benefit will depend on the distribution of outage lengths. We might expect facilities in sparsely-populated areas or coastal areas prone to hurricanes to be more likely to experience long grid outages, and thus be places where this benefit is especially high.

Bounding Analysis

Equation H.4 describes the expected benefit of a nuclear generator vs a fossil-fueled generator for which an optimal amount of fuel is available for backup operations, but not enough to supply electricity throughout the longest possible outage. Alternatively, we could evaluate equation H.4 as if there was enough fuel for the longest possible outage. This would eliminate the resilience benefit and leave only the cost benefit:

$$R(\bar{X}) = c\int_0^{\bar{X}} vf(v)dv + g(\bar{X}).$$

For a simplified case where all outages have duration $\bar{X}$, and the cost of storage is linear with the amount of fuel, $g(x) = g_o'x$, then the expected annual benefit is $R(\bar{X}) = (cp + g_o')\bar{X}$. The net present value of this benefit would be $\kappa(cp + g_o')\bar{X}$, and can be used to offset the higher capital cost of the nuclear reactor deployment.

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Appendix I
Microreactor Generator model used in HOMER analysis

In Chapter 4 we describe an analysis that relies on adapting the HOMER software to accommodate a nuclear reactor as part of the mix of technologies being modeled in HOMER.

This appendix describes the microreactor generator model that we developed, and then incorporated, into the HOMER analysis.

Note that a variety of cost and performance information is required to build an electrical generator model in HOMER. The table below shows the input parameters that are required in order to create a new generator model in HOMER. A nuclear reactor has additional properties that need to be part of the model and these new parameters had to be incorporated in a consistent manner within the list of model parameters already built into HOMER.

HOMER Generic Generator: Microreactor Model Inputs

Table I.1 provides a summary of the information needed to develop a HOMER generic generator model.

Table I.1: Input Variables to Define Generic Thermal Generator

Input Parameter	Input Parameter Description	Example Microreactor Input
Capacity (kWe)	Unit size capacity of generic generator	1000 kWe
Sizing (kWe)	Range over which the generic generator is used	1000 to 6000 kWe
Capital ($)	Capital cost of the generator	Include fuel as a replacement cost
Replacement ($)	Replacement cost of generator	Only fuel is the replacement cost
O&M Cost ($)	Generator fixed O&M costs	Include decommissioning cost
Replace. Lifetime (yr)	Lifetime of capital that is replaced	Lifetime based on fuel burnup
Minimum Load Ratio (%)	Load Ratio (0-1) absolute minimum load for generator operation	Not well known – assumed 25%
Fuel Price ($/kg)	Cost of fuel consumed	Fuel treated as a replacement cost

- Capacity refers to the nominal unit size of the generator (microreactor).
- Sizing refers to the size range of the generator modules that may be built to meet the desired capacity.
- Capital cost, as used in our model of a microreactor, is the capital cost of the microreactor (at the "Capacity" unit size) plus the cost of an initial core fuel loading.
- Replacement cost refers to the cost of replacing a generator or portions of a generator. As used in our model of a microreactor, this parameter is used to provide the cost of replacing the nuclear fuel.
- O&M cost refers to the operation and maintenance costs for a generator, on the basis of operational hours. If a generator is taken offline, it does not incur an "O&M" cost. For our model of a microreactor, we have annualized the cost of decommissioning and add that annual cost to the cost of O&M. These O&M costs are calculated under an assumption of a 100% capacity factor.
- Lifetime refers to the time (in years) between "Replacements" In the case of our model for a microreactor, it is the time between core refueling.
- Minimum Load Ratio refers to the absolute minimum load for the generator. If the generator load is predicted to be set below this minimum load ratio, the generator will be shut off. For microreactors, a reasonable value for this is not well known but 25% is now assumed.

Microreactor Fuel Cycle Cost

In this analysis we estimate the microreactor fuel cycle costs (FCCs) from prospective microreactor vendors, given that detailed core design data is currently unavailable. Since many of the potential microreactor vendors have chosen TRISO-based fuel, we use this fuel type as a surrogate in this analysis. This advanced fuel form has generic design data available (TRISO fuel kernel [cxviii] and X-Energy core design [cxix]). Initial fuel cycle cost estimates were performed for this fuel form with general cost data provided from the ANL fuel cycle cost calculator [cxx].

The Fuel Cycle Cost is equal to the cost of the fuel loaded into the reactor divided by the energy derived from that fuel mass. Neglecting the cost of money, the fuel cycle cost is given by:

$$FCC = \frac{C_{prod}}{24 * B * \eta_{th}},$$

where:

- FCC = Fuel Cycle Cost estimate for HOMER simulations. [$/MWh-e]
- C_{prod} = Cost of fuel product (shown below). [$/kg]
- B = Reactor Fuel Burnup, a measure of how much thermal energy was extracted from the fuel during its time in the reactor. [MWd-th/kg]
- η_{th} = Reactor thermal efficiency [MWe/MWth]
- 24 = Conversion between MWd and MWh [hr/d]

The cost of the fuel product is broken down into specific fuel cycle steps:

$$C_{PROD} = C_{FEED}\frac{F}{P} + C_{SEP}\frac{S}{P} + C_{FAB} + C_{DISP}$$

C_{FEED}= Mining&Milling + Conversion = 33 to 110 $/lbm (73 to 242 $/kg)
C_{SEP} = Enrichment/Reconversion = 66 to 120 $/kg
C_{FAB} = Fuel-Fabrication = 200-500$/kg (This is used as an estimate for TRISO)
C_{DISP} = Refuel-Transport-Storage-Disposal => neglect as small in comparison

The enrichment is assumed to be in the range of 15% to 20% ^{235}U.

- F/P – Ratio of feedstock mass input vs. final product mass.
- S/P – Ratio of how much separative work is required per unit mass enriched.
- Uranium tails concentration is assumed to be 0.2% ^{235}U (weight percent)

For example, estimating the lower cost FCC estimate using computed values [cxxi] for F/P and S/P:

15% ^{235}U => $\frac{F}{P}$=29 $\frac{S}{P}$=33.2

20% ^{235}U => $\frac{F}{P}$=38.8 $\frac{S}{P}$=45.7

- Lower cost at 15% => C_{PROD} = 29(72.6 \$/kg) + 33.2(66 \$/kg) + 200 \$/kg = 4500 \$/kg
- Lower cost at 20% => C_{PROD} = 38.7(72.6 \$/kg) + 45.7(66 \$/kg) + 200 \$/kg = 6030 \$/kg

Depending on reactor design, the burnup is assumed to be: B = 100-150 GW-d/mton

Thermal Efficiency is assumed to be 37% (based on selected gas-cooled reactor designs)

Table I.2: Nuclear Fuel Cycle Cost Ranges as a Function of Enrichment

Enrichment (%^{235}U)	Burnup (GWd/mton)	Lower Fuel Cycle Cost (\$/MWh)	Higher Fuel Cycle Cost (\$/MWh)
15	100	5	12.9
20	150	4.7	11.5

Fuel Core Mass Calculation

Based on the X-Energy design, we calculate the fuel mass in the core design. This is needed to compute the cost of the fuel load, which is then taken as the replacement cost. The core mass for the smaller microreactor designs is proportional to the microreactor thermal energy output.

There are about 23,000 TRISO kernels per pebble with 1000 Pebbles/MWth for 20 MWth size. The UCO fuel density is 10,600kg/m^3 with a kernel diameter of 0.425mm UCO;

$$V_{kernel} = \frac{4\pi}{3}\left(\frac{0.425mm}{2}\cdot\frac{10^{-3}m}{mm}\right)^3 = 4.0194\times10^{-11}\ \mathrm{m}^3 \quad (1)$$

$$V_{fuel} = V_{kernel}\left(\frac{kernels}{pebble}\right)\left(\frac{pebbles}{MWth}\right)P_{reactor}$$

$$V_{fuel} = 4.0194\times10^{-11}m^3\left(23{,}000\frac{kernels}{pebble}\right)\left(1000\frac{pebbles}{MWth}\right)20MWth = 0.01849\ m^3 \quad (2)$$

$$m_{fuel} = V_{fuel}\rho_{fuel} = 0.01849m^3\cdot 10{,}600\frac{kg}{m^3} = 196\ kg\mathrm{UCO}$$

HOMER Results for Microreactor Models

Two different approaches were developed to represent the fuel cycle cost. In one approach, we treat the fuel as a capital investment (capital cost model, CCM) which is expended given a certain enrichment and burnup and must be replaced with a core reload. In the other approach, we treat the fuel as if it were like a fossil fuel being continuously fed into the reactor and consumed (continuous feed model, CFM). The latter is more amenable to the HOMER generator customized model but requires auxiliary calculations. We have utilized both approaches in our analysis. As shown below, either approach yields similar results.

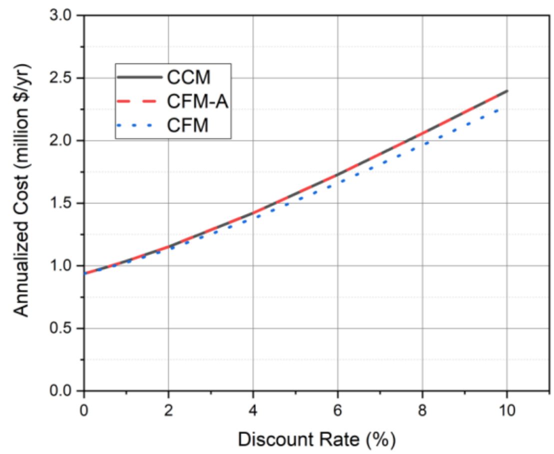

Figure I.1: Annualized Cost @ 4 MWe : CFM-A considers the cost of money on continuous feed cost

In the main report, we used this HOMER model to consider the case of a carbon-free on-site power generation using a microreactor with solar PV and battery storage. We performed a series of HOMER simulations to determine the mix of generation that would provide the lowest cost option for a range of cost assumptions. Below, we provide specific results for the two microreactor fuel cycle cost models. We note that the overall costs for this mix of technologies are the same regardless of the Nuclear Fuel Cycle cost model used within the variability of the HOMER optimization solution technique (local minimum costs can vary a few percent).

Table I.3: HOMER Simulations
(Surrogate Site: Peak Load – 6.3 MWe, Avg. Load – 4 MWe, Madison weather)

Case No.	Micro-Reac Size [A] (MWe)	Nuclear Costs	PV-Battery Costs	Nuclear Size (MWe)	PV Solar Size (MWe)	Battery Size (kWh)	Annual Level. Cost [D] ($ Mill/yr)	Levelized Cost of Elec. ($/MWh)
3	4 – 7 (.5)	Medium [B]	Best	5.0	7.76	6,107	4.67	133
4	3 – 6 (.5)	Medium [C]	Best	5.5	10.8	614	4.38	123

Note A: Microreactor size range (e.g., 1-7) along with incremental variation in that range (i.e., 0.5 or 1)
Note B: Capital Cost Method for Nuclear Fuel Model
Note C: Continuous Feed Model for Nuclear Fuel Model
Note D: Levelized cost of generation without microgrid or backup costs included

HOMER Microreactor Input Tables

In order to conduct a HOMER optimization with a microreactor, one can use Table I.4 provided below that contain input data normalized per MWe output.

Table I.4: Fuel Costs, Decommission Costs and O&M Costs for 1.0 MWe (2.70 MWth)

Cost Case	Units	Low Cost		Medium Cost	
Enrichment Case		20%	15%	20%	15%
Size Increment	MWe	1	1	1	1
Thermal Power	MWth	2.7	2.7	2.7	2.7
Core Replacement Time	yr	12.37 yr	8.25	12.37	8.25
Core U-mass	kg	81.3 kg	81.3	81.3	81.3
Burnup	MWd/kg	150	100	150	100
System Capital Cost	$M	4	4	12	$ 12
Fuel consumed	kg/h/kWe	2.09×10^{-7}	3.13×10^{-7}	2.09×10^{-7}	3.13×10^{-7}
Fuel Energy Content (LHV)	GJ/kg	12960	8640	12960	8640
Fuel Capital Cost	$M	0.491	0.366	1.25	0.935
Fuel Unit Cost	$/kg	6030	4500	15,400	11,480
Reactor O&M Cost	$/yr	100,000	100,000	250,000	250,000
Reactor Decommissioning	$/yr	28,000	28,000	43,000	43,000
Total Initial Cap. Cost	**$M**	**4.49**	**4.37**	**13.25**	**12.93**
Total – Replacement	**$M**	**0.491**	**0.366**	**1.25**	**0.935**
Total - O&M	**$M**	**0.13**	**0.13**	**0.29**	**0.29**
Total - O&M (100% Capacity Factor)	**$/op.hr**	**14.60**	**14.60**	**33.42**	**33.42**

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Appendix J
Case studies - Detailed Summary Sheets

UW Campus - Energy Data Report

Power Plants Located on the UW Campus

There are three power plants that are sited on the UW campus and have the capacity to supply the energy needs of the UW for heating, cooling and electricity.

1. The Charter Street Heating Plant (CSHP)
2. The West Campus Cogeneration Facility (WCCF)
3. The Walnut Street Heating Plant (WSHP)

The locations of these plants are shown in Figure J.1 below:

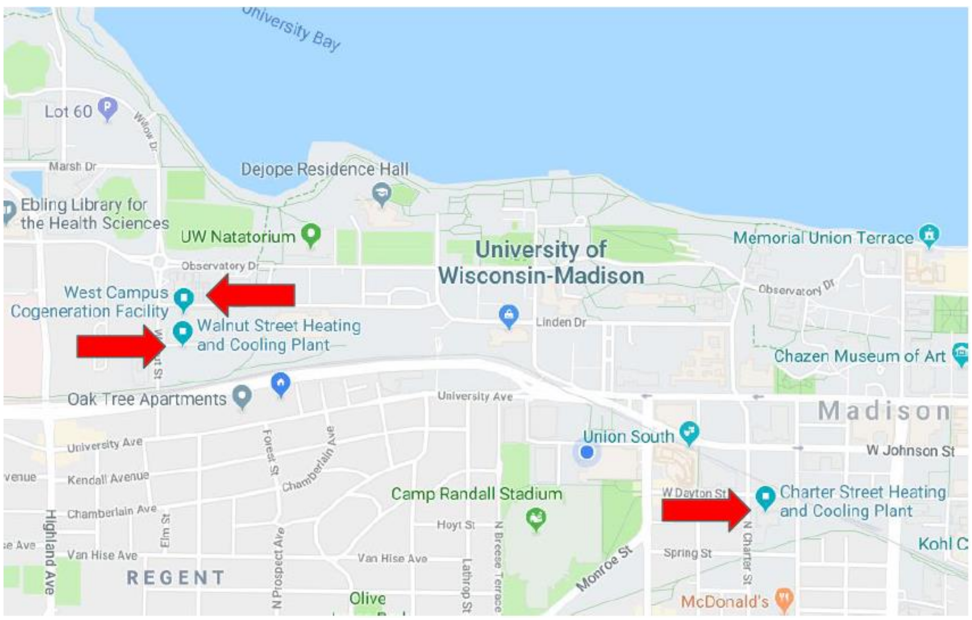

Figure J.1: Map showing locations of UW-Madison energy facilities

Of these, CSHP and WSHP are UW-owned, while WCCF is an MG&E facility that is co-owned by MG&E and the UW. All three plants are connected by a chilled water piping system and a steam and condensate piping system and are connected to the electrical transmission grid as well. Steam is supplied to campus for building heating requirements. Chilled water is used for building air-conditioning, where CSHP has 4 steam turbine-driven chillers, WCCF has 4-6 electric motor-driven chillers, and WSHP has 2 electric motor-driven chillers and 2 steam-turbine driven chillers. CSHP and WSHP are also connected with compressed air lines that distribute compressed air for building HVAC systems and for control systems (e.g., for servo mechanisms, where they exist) as well.

In addition to these three plants, there are 108 building electrical generators associated with individual buildings on campus. These are primarily used for supplying emergency backup electrical power with varying individual generator capacities (5 kW - 2000 kW) and total capacity of 36,175 kW.

The sections below describe these power plants in more detail.

Charter Street Heating Plant (CSHP): CSHP is a cogeneration plant owned and operated by UW. About 8 years ago, it switched its fuel from coal to natural gas. It consists of 5 natural gas boilers which can produce a maximum of 1.2M lbm/hr of steam (600 psig and 725°F). The load following back pressure steam turbine generator (BP) can produce up to 9.7 MWe of electricity, but normally produces less as a cogeneration plant it produces both steam and electricity - in this case, the *steam demand* is what drives the BP and determines how much electricity is produced. For example, during the spring and fall months, the heating/cooling demand is not very high, which is why the electricity generated is also at a minimum during these months. The BP turbine is the only source of non-emergency electricity generation that is owned by UW.

The natural gas boilers generate steam that is used to:

- Heat campus buildings and two hospitals
- Run the BP turbine
- Power the steam turbine-driven chillers at CSHP (4) and WSHP (2)
- Power 8 auxiliary steam turbines to support steam production at CSHP and WSHP

The backup fuel that can be used for these boilers is 840,000 gallons of fuel oil in a single tank with duration of approximately 5 days. This was used during the recent cold weather days (Jan. 29 to Feb. 1, 2019, polar vortex) when UW was cut off of natural gas supply due to low gas pressure in local pipelines.

Future plans: There are no plans to replace the BP turbine generator in the next 10-20 years. Future planning includes a 20 MW extraction/back pressure steam turbine generator and a 3 MW condensing steam turbine generator, situated adjacent to CSHP. Situating the 20 MW BP turbine at CSHP is preferred, but the 3 MW could be sited next to WSHP as well. In addition to these, a 10,000 ton electric chiller plant and 8 million gallon thermal energy storage tank in also included in these future plans. These additions are being planned not as much for growth (since MG&E is capable of providing the expected UW needs), but more so for improving the resiliency of the campus, energy savings and carbon reduction. Implementation of these plans is dependent on future State funding. Given the above plan is funded, the intent is also to introduce microgrid technology using CSHP as the production facility. There are no plans to eliminate local building generators in this process.

West Campus Cogeneration Facility (WCCF): WCCF is a cogeneration facility jointly owned by MG&E and UW. The co-ownership was negotiated by the State 14 years ago when WCCF was built. It was a $180 million project, with both UW and MG&E contributing nearly equal shares (~$90 million each). The electricity generation assets at WCCF (e.g., switch gears, generators, all electrical distribution) are entirely owned by MG&E. The cooling assets (steam and chilled water) are entirely owned by UW - this includes the chillers that provide chilled water for cooling only to the UW campus. The thermal assets, which include everything else - combustion and steam turbines, heat recovery boilers, etc. - are owned 75% by MG&E and 25% by UW.

WCCF consists of two 45 MW combustion turbine generators and a condensing steam turbine generator which produces 68 MW. Together, these generate more than 150 MW of electrical power.

UW purchases power from MG&E (as a customer in the MISO grid), which is generated from various sources including WCCF. The power received from WCCF, used to produce chilled water, is *internal* *power* and considered station service. When WCCF is operational and running, the power is charged to UW as a **fuel expense**. When WCCF is off-line, the electricity for the chillers is drawn from the MISO grid at a commercial rate (SP-3 rate structure) - therefore, in this case, power is charged to UW as an **electric cost** to campus.

Walnut Street Heating Plant (WSHP): WSHP is a supplemental heating and cooling plant only, owned and operated by UW for on-campus usage. It is used as a peaking plant with 3 natural gas boilers which can produce a maximum of 500k lbm/hr of steam (175 psig, saturated). The chillers include 2 electric and 2 steam turbine-driven chillers.

Annual Consumption of Energy (FY18):

Breakdown of electricity consumption: On-site electricity generation at UW consists of non-emergency generation capacity of 9.7 MW (BP turbine at CSHP), and backup generation capacity of 1.75 MW (1 MW and 0.75 MW diesel generators at CSHP and WSHP, respectively). During FY18, UW imported an average of ~50 MW of electricity from MG&E, and generated an average of ~2 MW on-site (CSHP). Therefore, the average load in FY18 was ~52 MW, which includes contiguous consumption by the campus as well as the WCCF chiller plant. The peak was ~82 MW. On average, UW is 10% of MG&E load, with peaking in early September.

Figure J.2 shows the data for electricity consumption for FY18, representing the total electric load [kWh] as recorded every 15 minutes, for every day from July 1, 2017 to June 30, 2018. Figure J.3 shows a breakdown of where the electricity is supplied from - WCCF, CSHP and as purchased from MG&E. The electric load profile of this raw data is shown in the charts below. The first chart shows the total electric consumption, while the second chart shows how much of this total supply comes from the three different sources.

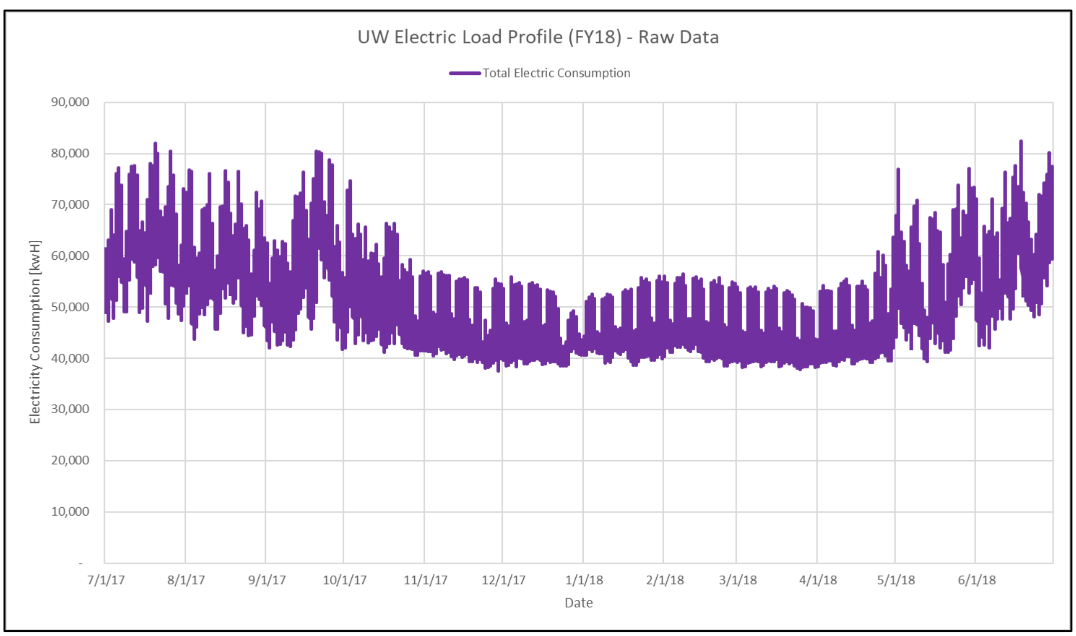

Figure J.2: Total UW-Madison Hourly Electricity Consumption in 15 minute Intervals

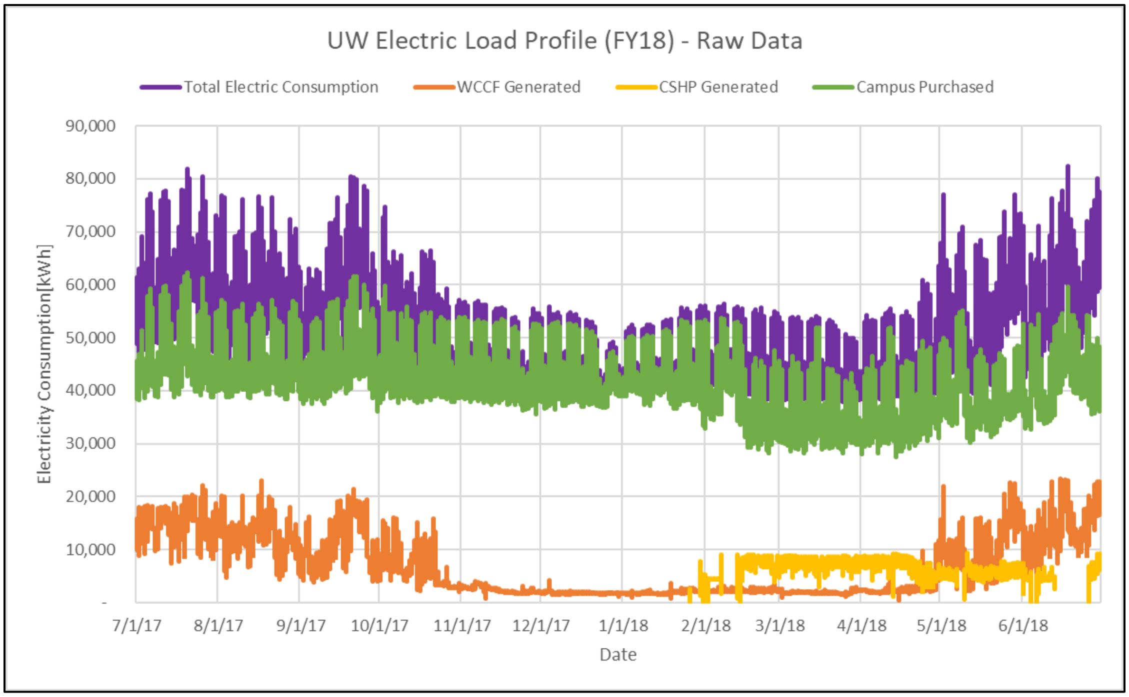

Figure J.3: Hourly Electricity Consumption by Source at UW-Madison in 15 Minute Intervals

The average electricity consumed per day [kWh] is shown below in Figure J.4:

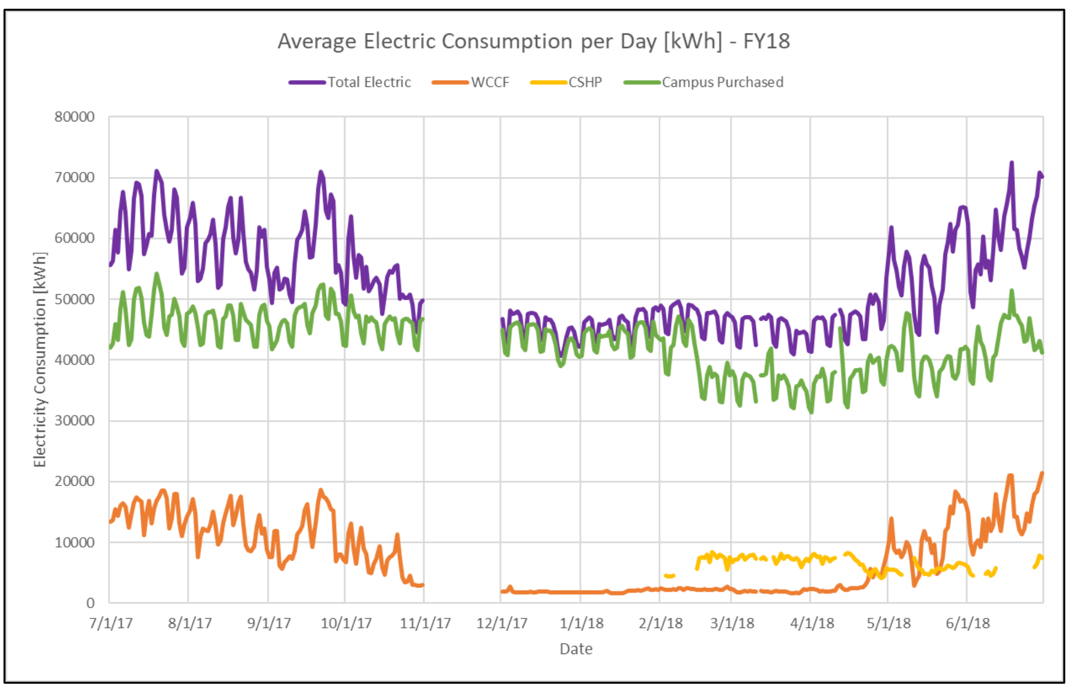

Figure J.4: Daily Average of Hourly Electricity Consumption at UW-Madison

The hourly average electric load profile [kW] for FY18 is shown below:

Breakdown of heat consumption: During FY18, the average consumption of heat was ~116 MW, with a peak of ~245 MW. The load profile for total steam demand [lb/hr] in FY18 is shown below in Figure J.5:

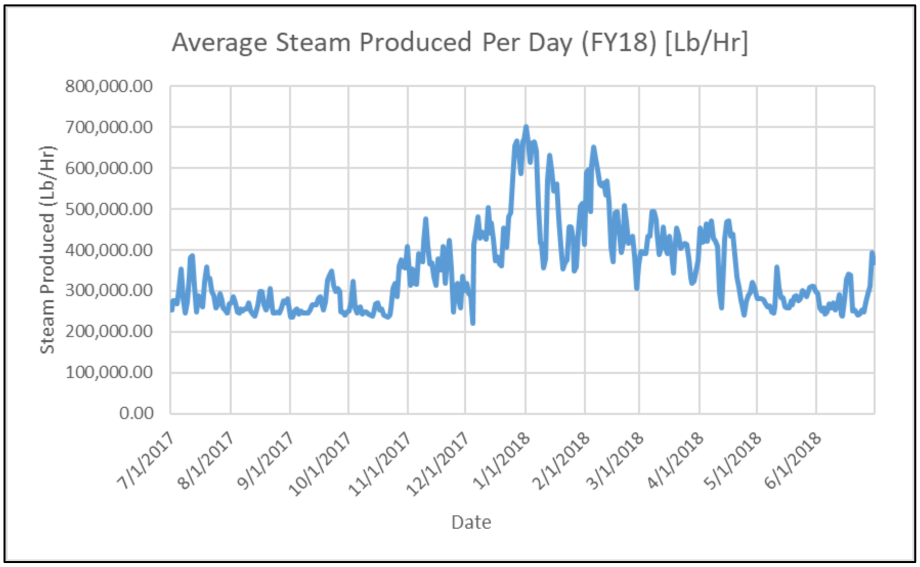

Figure J.5: Daily Average of Hourly Steam Production at UW-Madison

Conversion of steam load profile from [lbs/hr] to [BTU/hr] and [MWth]: The steam is produced at a pressure of 600 psig (42.46 bar) and a temperature of 725°F (385°C). This corresponds to an enthalpy of 3179 kJ/kg.

The load profile in [BTU/hr] is obtained using the following calculation:

$$x\left[\frac{lb}{hr}\right]\cdot 3179\left[\frac{kJ}{kg}\right]\cdot\frac{1}{2.2}\left[\frac{kg}{lb}\right]\cdot\frac{1}{1055}\left[\frac{BTU}{J}\right] = 1367x\left[\frac{BTU}{hr}\right]$$

where x is the steam production rate in [lb/hr].

Similarly, the load profile in [MWth] is obtained using the following calculation:

$$y\left[\frac{BTU}{hr}\right]\cdot 1055\left[\frac{J}{BTU}\right]\cdot\frac{1}{3600}\left[\frac{hr}{s}\right] = \frac{y}{3.41}\left[\frac{J}{s}\right] = 10^{-6}\frac{y}{3.41}[MWth]$$

Where y is the power required to generate the steam in [BTU/hr].

Therefore, the steam load profiles in [BTU/hr] and [MWth] thus calculated are shown in Figure J.6 and Figure J.7 below:

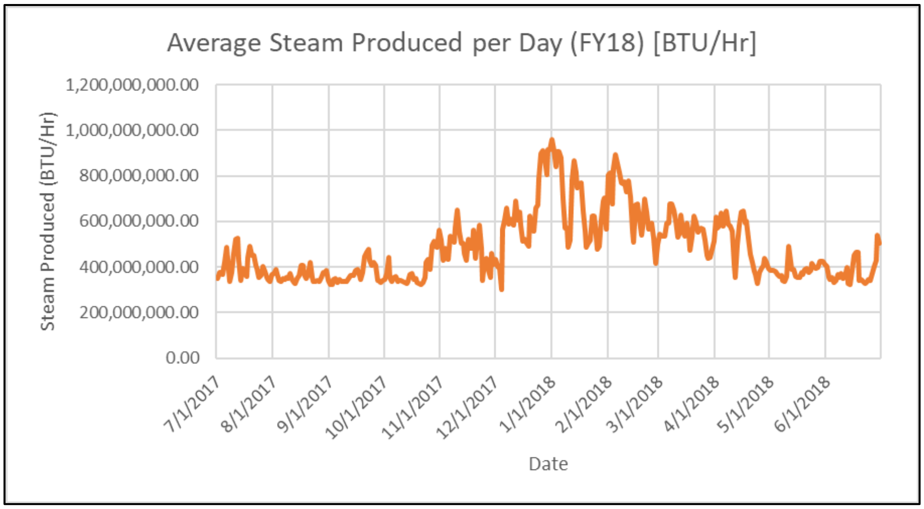

Figure J.6: Energy Consumption for Steam Production Averaged Over Each Day

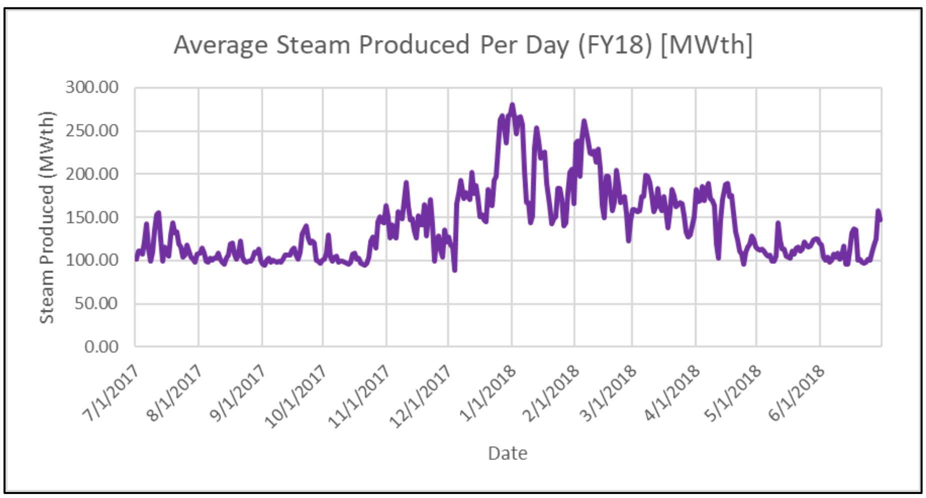

Figure J.7: Energy Consumption for Steam Production Averaged Over Each Day

Breakdown of steam production: In terms of steam requirements, CSHP is the lead plant, followed by WCCF and then by WSHP (only peaking). WCCF is used for steam in the winter months (October-April), because below 40°F the pressure in the campus steam piping loop starts dropping below an acceptable level as it reaches the UW hospital. Because of this reason, as well as ease of operation and economics, CSHP dispatches the amount of steam it produces until it reaches its maximum capacity, after which WCCF is asked to step in from October-April.

From CSHP, a high-pressure steam loop (175 psi) and a smaller low-pressure sub-loop (13.5 psi) emerge. The steam loop is normally 175 psi of saturated steam unless it is augmented by extraction steam that then goes to the sub-loop. The sub-loop provides steam to facilities at Bascom Hill, the Agricultural Campus, etc.

Breakdown of the steam produced from FY14-FY18 is shown in Table below:

Table J.1: Historical Annual Steam Production at each UW-Madison Facility

Steam Produced in MMBTU				
Year	**CSHP**	**WSHP**	**WCCF**	**Total**
FY14 (July 13-June 14)	3,144,363	658,513	115,702	3,918,578
FY15 (July 14-June 15)	2,622,610	852,842	137,316	3,612,767
FY16 (July 15-June 16)	2,728,800	185,115	410,125	3,324,039
FY17 (July 16-June 17)	2,751,337	30,397	391,041	3,172,775
FY18 (July 17-June 18)	3,037,069	17,813	414,270	3,469,152

Total energy consumption: During FY18, the average consumption of total energy (electricity + heat) was ~168 MW, with a peak of ~288 MW.

Building Generators

There are 108 natural gas/diesel generators installed on individual buildings across campus, which are used for emergency backup power. In addition to this, there are 7 portable natural gas generators.

Figure J.8 and Figure J.9 below show the distribution of generator size and age, respectively.

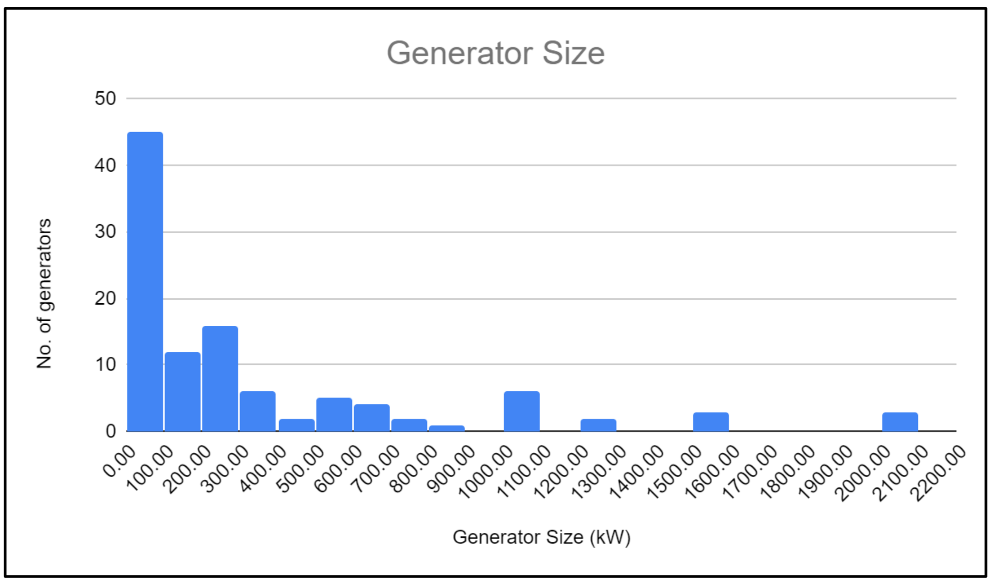

Figure J.8: Distribution of Backup Generator Size at UW-Madison

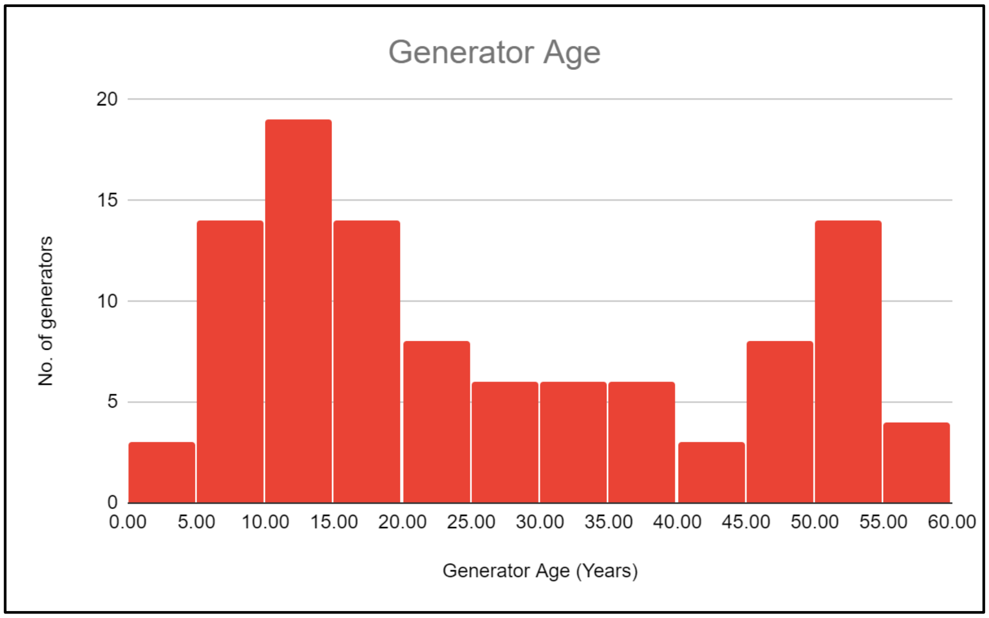

Figure J.9: Distribution of Backup Generator Age at UW-Madison

All the generators can run to their full potential based on the loads they need to pick up. On average, they are estimated to be running at 40% of their rated capacity. They are all designed and installed per applicable codes and regulations set forth by the NFPA and the Wisconsin State Master Specifications Design Guidelines.

The generators ramp up automatically if the buildings they are connected to lose power. Their sole purpose is to provide emergency backup power, and they are not tied to CSHP in any way. The permits for these diesel generators only allow 48 hours of operation per year for testing purposes. They cannot be operated or dispatched to reduce peak electrical loads.

Currently, there are no cross-connections between the generators. Each generator serves the building's life safety systems and possibly some special systems and/or air handling systems in laboratory buildings. The cost of replacing or repurposing these generators would vary greatly based on the size of the generator, what it is being repurposed for, and the kind of engineering that would be required to make any changes. At present, there are no plans to consolidate the generators.

NASA – Johnson Space Center (JSC)

Site Characteristics

Johnson Space Center (JSC) consists of a complex of 100 buildings constructed on 2.5 Square miles (1,620 acres) in the Clear Lake Area of Houston. (See Figure J.10.) There are approximately 3,330 civilian employees at the facility, 105 buildings, 2 major substations, and 5 sectional sub-stations.

Figure J.10: Ariel views of Johnson Space Center

Utility connection:

On-grid: Utility is CenterPoint Energy

On-site power – current

There is one on-site non-emergency power plant within the JSC campus: a combined heat and power (CHP) plant. It was constructed as part of a major energy system renovation effort in 2011 by NASA at JSC designed to give the facility higher power resiliency and efficiency.

Funding was provided through the DOE's Energy Savings Performance Contracting (ESPC) partnership with Energy Systems Group, an energy service provider. This is a budget neutral approach to make building improvements that reduce energy and water usage while increasing operational efficiency. The bulk of the project costs, including installation, operation and maintenance, were borrowed through the energy services company and paid for with savings. In this project, utility budget savings are used to fund the ESPC over a 22 year period.

Description of the on-site power: combined heat and power (CHP) plant.

- Runs in parallel with power supplied by utility,
- Power level: 12 MW,
- Provides 70% of base electric load,
- Provides 100% of steam load (50,000 Lbs/hr),
- Adequate to cover critical load, should utility be disrupted,
- Composition: two 5.7 MW combustion turbines, one 500 kW Steam Turbine, and
- Fuel: natural gas.

Backup power

In addition to the CHP plant, JSC has 3.75 MW of diesels, use as backup for the CHP plant.

On-site power – future plans

JSC has a master plan which is renewed every five years. A major revision to the overall strategic plan is scheduled to be concluded by July 2021. JSC reports that they are comfortable with the existing configuration. Beyond 2021 there is an anticipated need to increase the capacity of critical on-site power (up to a factor of two) so as to enable a group of larger non-interruptible experimental and data analysis capabilities.

The on-site power plant was installed in 2011 and is paid for over 22 years. The O&M contract includes funds for new equipment and requires that equipment installed by the contractor (ESCO) will have at least 10 years of remaining operational life at the end of the contract term of twenty-two years. Thus, except for heightened concerns regarding resilience, the power needs for JSC over the next 10-20 years are covered adequately,

Microgrid

JSC has an existing system for distributing electricity and heat to the buildings on its campus.

As shown below in Figure J.11, prior to 2011, JSC used high pressure boilers to drive turbines, which then provided the chilled water supply to the campus. In the new configuration, two gas turbines and one steam turbine have been added to the system. Currently, the JSC Micro grid consists of a combined cycle combustion steam turbine system capable of 11.9 MW of continuous electrical and 25 MW of thermal energy supply.

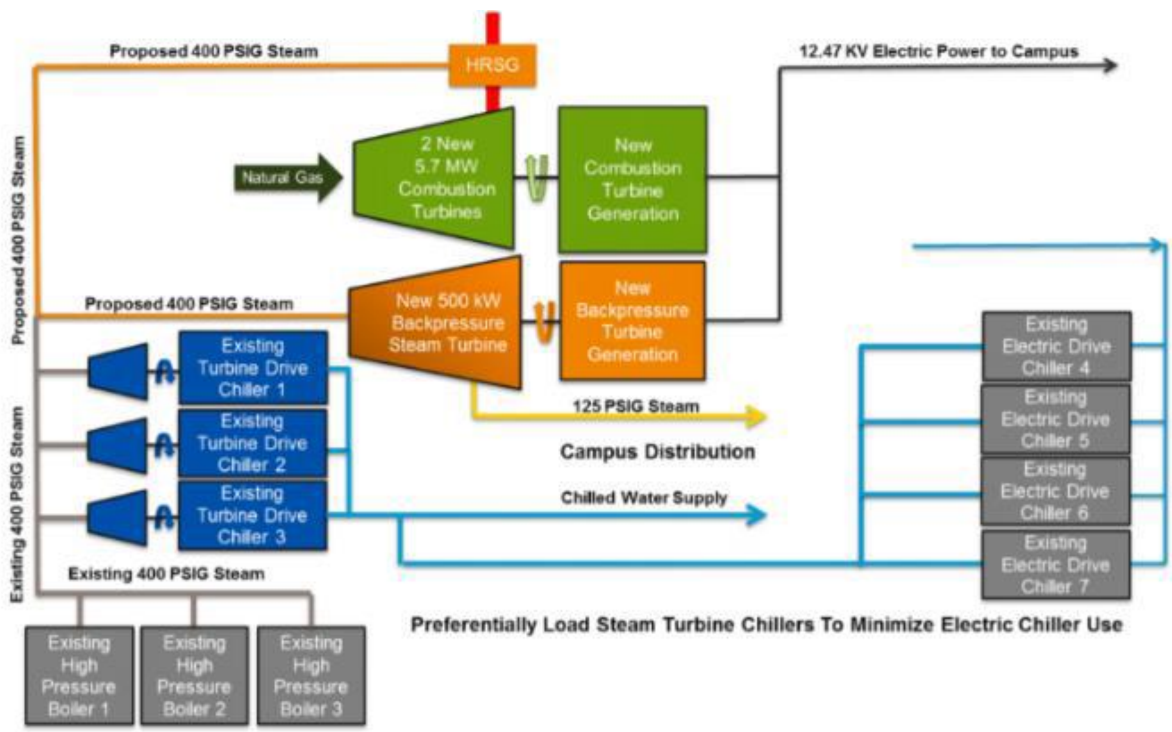

Figure J.11: Combined Heat and Power System for Johnson Space Center

Energy use (2018):

Table J.2: Historical Energy Consumption at Johnson Space Center

Installation Name	Johnson Space Center (JSC)
Average Electricity Consumed (MWe):	18
Peak Electrical Power (MWe):	24
Critical Electrical Power (MWe):	3.8
Average Heat Consumed (MWth):	20
Peak Thermal Power (MWth):	25
On the local electrical grid	Yes
Electricity charge ($/MWh-attached)	40 to 70

Resilience:

Resilience at JSC can be described as a system that approaches Scenario 3 in the current study. The on-site generation runs at a level that can support the critical load. Consistent with Scenario 2, the utility provides backup, should the on-site generation be unavailable; the on-site generation carries the critical load, should power from the utility become unavailable. In addition, however, JSC employs 3.75 MW of diesels to back up the on-site generator. These generators are both a product of 30 years of legacy operation and a realization that in a storm damage prone area traditional combined cycle local power generation has resiliency issues such as intake washout and turbine control flooding.

The above configuration does not provide a complete backup for the on-site power plant. Should the utility be unavailable, the CHP would carry 12 MW of the load with only 3.75 of that amount with diesel backup. The resilience of the system could be enhanced if a microreactor of >8 MWe were to be installed as additional on-site power with the CHP.

As part of ongoing discussion with JSC Energy System Leadership cost for outage estimates have been shared. We further compared these estimates to published "cost of outage numbers" from noted sources[cxxii]. Table J.3 below shows both the estimated JSC costs for outage as well as other reference costs from some studies examples in US locations.

Table J.3: Estimated Costs of Outages at Johnson Space Center

Interruption Cost	Interruption Duration					
	Momentary	30 Min	1Hr	4 Hr	8 Hr	16 Hr
Medium and Large C&I (over 50,000 Annual kWh)						
Cost Per Event	$12,952	$15,241	$17,804	$39,548	$84,083	$165,482
Cost per Ave kWh	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost Per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Ave kWh	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost Per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Ave kWh	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3
Critical Military Facility (over 40,000,000 Annual kWh)						
Cost Per Event	$18,295	$34,870	$188,210	$259,723	$296,754	$478,320
Cost per Ave kWh	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$33.0	$26.0	$27.0	$25.0
Johnson Space Center (over 40,000,000 Annual kWh campus, 40% critical load)						
Cost Per Event	$18,295	$34,870	$158,110	$175,680	$196,780	$300,650
Cost per Ave kWh	$19.6	$33.4	$197.0	$243.0	$381.0	$305.0
Cost per Unserved kWh	$200.3	$45.0	$43.0	$40.0	$35.4	$21.0

The Energy Systems Management team at JSC has expressed a willingness to assess the implementation of a micro reactor.

Additional points, raised up during the interview with the facilities energy manager, would be the benefits beyond those related to fuel costs or related operational costs. Those could be summarized as follows:

- Super Resilience, beyond the 5 nines that might be achieved with the existing combined cycle Microgrid and multiple emergency generator units.
- Perfect across campus power quality (2x better THD and flicker)
- Reduction in Demand Peak charges beyond what the existing Microgrid can Deliver.
- Improved Local Frequency and Voltage Control

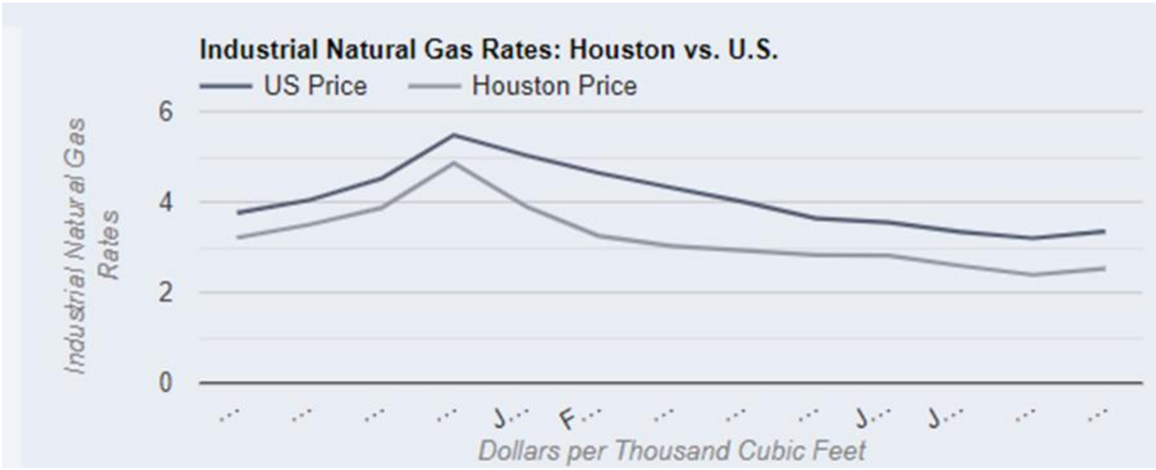

Figure J.12: Industrial Rates for Purchase of Natural Gas: Houston vs Average U.S.

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Appendix K
Relevant provisions from the Energy Act of 2020

Division EE

Taxpayer Certainty and Disaster Tax relief Act of 2020.

Examples include:

- Title I, Subtitle B, Sec 121, amends 26 USC 45Q(d)(1). Extends the Carbon (di-) Oxide Credit through 2026
- Title I, Subtitle C. Sec 131, amends - 26 USC Sec 45 (d) to extend the production credits for:
  - Wind
  - Closed-loop biomass
  - Open loop biomass
  - Geothermal or solar
  - Landfill gas
  - Trash facilities
  - Marine and hydrokinetic renewable energy facilities.
- Title I, Subtitle C Sec 142 amends (26 USC Sec 30B(k)(1)) to extend credits for fuel cell vehicles, but not for hybrid vehicles, or alternative fuel vehicles.
- Title I, Subtitle C Sec 144 amends (26USC Sec 30D9g)(3)E(ii) for 2-wheeled plug-in Electric vehicles.
- Title II, Sec 203(b) amends 26 USC 48(a)(2)(A)(i), extends a 30% credit for electricity produced from waste heat.
- Title II, Sec 204 amends 26 USC 48(a)(5). Extends credit for offshore wind.
- Note: this is not a complete list.

Division Z – Energy Act of 2020

Title II, SEC 2003. Amends 42 USC 16272 (EPACT-2005), adding Sec 952

(b) Advanced Reactor Technologies.

(1) IN GENERAL. – The Secretary shall carry out a program of research, development, demonstration and commercial application to support advanced reactor technologies.

(2) REQUIREMENTS. – In carrying out the program under this subsection, the Secretary shall

(A) prioritize designs for advanced nuclear reactors that are proliferation resistant and passively safe, including designs that, compared to reactors operating on the date of enactment of the Energy Act of 2020 –

(i) are economically competitive with other electric power generations plants;

‘‘(ii) have higher efficiency, lower cost, less environmental impacts, increased resilience, and improved safety;

‘‘(iii) use fuels that are proliferation resistant and have reduced production of high-level waste per unit of output; and

‘‘(iv) use advanced instrumentation and monitoring systems;

‘‘(B) consult with the Nuclear Regulatory Commission on appropriate metrics to consider for the criteria specified in subparagraph (A);

‘‘(C) support research and development to resolve materials challenges relating to extreme environments, including environments that contain high levels of—

‘‘(i) radiation fluence;

‘‘(ii) temperature;

‘‘(iii) pressure; and

‘‘(iv) corrosion;

‘‘(D) support research and development to aid in the qualification of advanced fuels, including fabrication techniques;

‘‘(E) support activities that address near-term challenges in modeling and simulation to enable accelerated design of and licensing of advanced nuclear reactors, including the identification of tools and methodologies for validating such modeling and simulation efforts;

‘‘(F) develop technologies, including technologies to manage, reduce, or reuse nuclear

waste;

‘‘(G) ensure that nuclear research infrastructure is maintained or constructed, including—

‘‘(i) currently operational research reactors at the National Laboratories and institutions of higher education;

‘‘(ii) hot cell research facilities;

‘‘(iii) a versatile fast neutron source;

and

‘‘(iv) advanced coolant testing facilities, including coolants such as lead, sodium, gas, and molten salt;

‘‘(H) improve scientific understanding of nonlight water coolant physics and chemistry;

‘‘(I) develop advanced sensors and control systems, including the identification of tools and methodologies for validating such sensors and systems;

‘‘(J) investigate advanced manufacturing and advanced construction techniques and materials to reduce the cost of advanced nuclear reactors, including the use of digital twins and of strategies to implement project and construction management best practices, and study the effects of radiation and corrosion on materials created with these techniques;

‘‘(K) consult with the Administrator of the National Nuclear Security Administration to integrate reactor safeguards and security into design;

‘‘(L) support efforts to reduce any technical barriers that would prevent commercial application of advanced nuclear energy systems;

and

‘‘(M) develop various safety analyses and emergency preparedness and response methodologies.

‘‘(3) COORDINATION.—The Secretary shall coordinate with individuals engaged <u>in the private sector and individuals who are experts in</u> nuclear nonproliferation, environmental and public health and safety, and <u>economics to advance the development of various designs of advanced nuclear reactors.</u> In carrying out this paragraph, the Secretary shall convene an advisory committee of such individuals and such committee shall submit annually a report to the relevant committees of Congress with respect to the progress of the program.

‘‘(c) NUCLEAR INTEGRATED ENERGY SYSTEMS RE SEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIAL APPLICATION PROGRAM.

‘‘(1) IN GENERAL.—The Secretary shall carry out a program of research, development, demonstration, and commercial application to develop nuclear integrated energy systems, composed of 2 or more co-located or jointly operated subsystems of energy generation, energy storage, or other technologies and in which not less than 1 such subsystem is a nuclear energy system, to—

‘‘(A) reduce greenhouse gas emissions in both the power and nonpower sectors; and

‘‘(B) maximize energy production and efficiency.

‘‘(2) COORDINATION.—In carrying out the program under paragraph (1), the Secretary shall coordinate with—

‘‘(A) relevant program offices within the Department of Energy;

‘‘(B) National Laboratories;

‘‘(C) institutions of higher education; and

‘‘(D) the private sector.

‘‘(3) FOCUS AREAS.—The program under paragraph (1) may include research, development, demonstration, or commercial application of nuclear integrated energy systems with respect to—

‘‘(A) desalination technologies and processes;

‘‘(B) hydrogen or other liquid and gaseous fuel or chemical production;

‘‘(C) heat for industrial processes;

‘‘(D) district heating;

‘‘(E) heat or electricity generation and storage;

‘‘(F) carbon capture, use, utilization, and storage;

‘‘(G) microgrid or island applications;

‘‘(H) integrated systems modeling, analysis, and optimization, inclusive of different configurations of integrated energy systems;

‘‘(I) integrated design, planning, building, and operation of systems with existing infrastructure, including interconnection requirements with the electric grid, as appropriate.

‘‘SEC. 959A. ADVANCED REACTOR DEMONSTRATION PROGRAM.

‘‘(a) DEMONSTRATION PROJECT DEFINED.—For the purposes of this section, the term ‘demonstration project’ means an advanced nuclear reactor operated in any manner, including as part of the power generation facilities of an electric utility system, for the purpose of demonstrating the suitability for commercial application of the advanced nuclear reactor.

‘‘(b) ESTABLISHMENT.—The Secretary shall establish a program to advance the research, development, demonstration, and commercial application of domestic advanced, affordable, nuclear energy technologies by—

‘‘(1) demonstrating a variety of advanced nuclear reactor technologies, including those that could be used to produce—

‘‘(A) safer, emissions-free power at a competitive cost of electricity compared to other new energy generation technologies on the date of enactment of the Energy Act of 2020;

‘‘(B) heat for community heating, industrial purposes, heat storage, or synthetic fuel production;

‘(C) remote or off-grid energy supply; or

‘‘(D) **backup or mission-critical power supplies;**

‘‘(2) identifying research areas that the private sector is unable or unwilling to undertake due to the cost of, or risks associated with, the research; and

‘‘(3) facilitating the access of the private sector—

‘‘(A) to Federal research facilities and personnel; and

‘‘(B) to the results of research relating to civil nuclear technology funded by the Federal Government.

‘‘(c) DEMONSTRATION PROJECTS.—In carrying out demonstration projects under the program established in subsection (b), the Secretary shall—

‘‘(1) include, as an evaluation criterion, **diversity in designs** for the advanced nuclear reactors demonstrated under this section, including designs using various

‘‘(A) primary coolants;

‘‘(B) fuel types and compositions; and

‘‘(C) neutron spectra;

‘‘(2) consider, as evaluation criterions—

‘‘(A) the likelihood that the operating cost for future commercial units for each design implemented through a demonstration project under this subsection is cost-competitive in the applicable market, including those designs configured as integrated energy systems as described in section 952(c);

‘‘(B) the technology readiness level of a proposed advanced nuclear reactor technology;

‘‘(C) the technical abilities and qualifications of teams desiring to demonstrate a proposed advanced nuclear reactor technology; and

‘‘(D) the capacity to meet cost-share requirements of the Department;

‘‘(3) ensure that each evaluation of candidate technologies for the demonstration projects is completed through an external review of proposed designs, which review shall—

‘‘(A) be conducted by a panel that includes not fewer than 1 representative that does **not have a conflict of interest** of each within the applicable market of the design of—

‘‘(i) an electric utility;

‘‘(ii) an entity that uses high-temperature process heat for manufacturing or industrial processing, such as a petrochemical or synthetic fuel company, a manufacturer of metals or chemicals, or a manufacturer of concrete;

‘‘(iii) an expert from the investment community;

‘‘(iv) a project management practitioner; and

‘‘(v) an environmental health and safety expert; and

‘‘(B) include a review of each demonstration project under this subsection which shall include consideration of cost-competitiveness and other value streams, together with the technology readiness level, the technical abilities and qualifications of teams desiring to demonstrate a proposed advanced nuclear reactor technology, the capacity to meet cost-share requirements of the Department, if Federal funding is provided, and environmental impacts;

‘‘(4) for federally funded demonstration projects, enter into cost-sharing agreements with private sector partners in accordance with section 988 for the conduct of activities relating to the research, development, and demonstration of advanced nuclear reactor designs under the program;

‘‘(5) consult with—

‘‘(A) National Laboratories;

‘‘(B) institutions of higher education;

‘‘(C) traditional end users (such as electric utilities);

‘‘(D) potential end users of new technologies (such as users of high-temperature process heat for manufacturing processing, including petrochemical or synthetic fuel companies, manufacturers of metals or chemicals, or manufacturers of concrete);

‘‘(E) developers of advanced nuclear reactor technology;

‘‘(F) environmental and public health and safety experts; and

‘‘(G) non-proliferation experts;

‘‘(6) seek to ensure that the demonstration projects carried out under this section do not cause any delay in the progress of an advanced reactor project by private industry and the Department of Energy that is underway as of the date of enactment of this section;

‘‘(7) establish a streamlined approval process for expedited contracting between awardees and the Department;

“(8) identify technical challenges to candidate technologies;

“(9) support near-term research and development to address the highest risk technical challenges to the successful demonstration of a selected advanced reactor technology, in accordance with—

“(A) paragraph (8);

“(B) the research and development activities under section 952(b); and

“(C) the research and development activities under section 958; and

“(10) establish such technology advisory working groups as the Secretary determines to be appropriate to advise the Secretary regarding the technical challenges identified under paragraph (8) and the scope of research and development programs to address the challenges, in accordance with paragraph (9), to be comprised of—

“(A) private sector advanced nuclear reactor technology developers;

“(B) technical experts with respect to the relevant technologies at institutions of higher education;

“(C) technical experts at the National Laboratories;

“(D) environmental and public health and safety experts;

“(E) non-proliferation experts; and

“(F) any other entities the Secretary determines appropriate.

“(d) MILESTONE-BASED DEMONSTRATION

PROJECTS.—The Secretary may carry out demonstration projects under subsection (c) as a milestone-based demonstration project under section 9005 of the Energy Act of 2020.

“(e) NONDUPLICATION.—Entities may not receive funds under this program if receiving funds from another reactor demonstration program at the Department in the same fiscal year.

Title IX—Department Of Energy Innovation

SEC. 9004. STREAMLINING PRIZE COMPETITIONS.

Section 1008 of the Energy Policy Act of 2005 (42 U.S.C. 16396) is amended by inserting after subsection (d) the following (and redesignating subsections (f) and (g) as subsections (g) and (h), respectively):

“(e) COORDINATION.—In carrying out subsection (a), and for any prize competitions under section 105 of the America Creating Opportunities to Meaningfully Promote

Excellence in Technology, Education, and Science Reauthorization Act of 2010, the Secretary shall—

''(1) issue Department-wide guidance on the design, development, and implementation of prize competitions;

''(2) collect and disseminate best practices on the design and administration of prize competitions;

''(3) streamline contracting mechanisms for the implementation of prize competitions; and

''(4) provide training and prize competition design support, as necessary, to Department staff to develop prize competitions and challenges.''.

SEC. 9005. MILESTONE-BASED DEMONSTRATION PROJECTS.

(a) IN GENERAL.—Acting under section 646(g) of the Department of Energy Organization Act (42 U.S.C. 7256(g)), notwithstanding paragraph (10) of such section, the Secretary of Energy (in this section referred to as the ''Secretary'') may carry out demonstration projects as a milestone-based demonstration project that requires particular technical and financial milestones to be met before a participant is awarded grants by the Department through a competitive award process.

(b) REQUIREMENTS.—In carrying out milestone based demonstration projects under the authority in paragraph (1), the Secretary shall, for each relevant project—

(1) request proposals from eligible entities, as determined by the Secretary, including—

(A) a business plan, that may include a plan for scalable manufacturing and a plan for addressing supply chain gaps

(B) a plan for raising private sector investment; and

(C) proposed technical and financial milestones, including estimated project timelines and total costs; and

(2) award funding of a predetermined amount to projects that successfully meet proposed milestones under paragraph (1)(C) or for expenses deemed reimbursable by the Secretary, in accordance with terms negotiated for an individual award;

(3) require cost sharing in accordance with section 988 of the Energy Policy Act of 2005; and

(4) communicate regularly with selected eligible entities and, if the Secretary deems appropriate, exercise small amounts of flexibility for technical and financial milestones as projects mature.

(c) AWARDS.—For the program established under

subsection (a)—

(1) an award recipient shall be responsible for all costs until milestones are achieved, or reimbursable expenses are reviewed and verified by the Department; and

(2) should an awardee not meet the milestones described in subsection (a), the Secretary or their designee may end the partnership with an award recipient and use the remaining funds in the ended agreement for new or existing projects carried out under this section.

(d) PROJECT MANAGEMENT.—In carrying out projects under this program and assessing the completion of their milestones in accordance with subsection (b), the Secretary shall consult with experts that represent diverse perspectives and professional experiences, including those from the private sector, to ensure a complete and thorough review.

(e) REPORT.—In accordance with section 9007(a), the Secretary shall report annually on any demonstration projects carried out using the authorities under this section.

SEC. 9006. OTHER TRANSACTION AUTHORITY EXTENSION.

(a) Subsection 646(g)(10) of the Department of Energy Organization Act (42 U.S.C. 7256(g)(10)) is amended by striking ''September 30, 2020'' and inserting ''September 30, 2030''.

(b) The provisions of section 602 of the Public Works and Economic Development Act of 1965 (42 U.S.C. 3212) shall apply with respect to construction, alteration, or repair work of demonstration projects funded by grants or contracts authorized under sections 3001, 3003, 3004, 5001, and 8007 and the amendments made by such sections.

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Appendix L
University of Wisconsin Team

Thomas Palmieri is currently a consultant to the Institute for Nuclear Energy Systems, University of Wisconsin. Dr. Palmieri received his degree in Physics at the University of Wisconsin and has held scientific positions at Lawrence Livermore National Lab, Sandia Laboratories, and the Centre d'Etudes Nucleaire de Saclay in France. From 1978-1992 he served as Branch Chief for DOE programs at the Office of Management and Budget. From 2000-2001, he was Deputy Chief Financial Officer of the Department of Energy and from 2001 to 2003 was Chief Financial Officer at the Los Alamos National Laboratory. He has served as staff for two Senate Committees: in 1977-1978 assisting Senator Robert Dole on the Senate Finance Committee, and 1997-1998 on the staff of the Senate Government Affairs Committee. He played a major role in the development of energy policy during three Administrations, including negotiations among USG agencies in the development of international energy and nonproliferation programs. He assisted the Office of the President in the creation of energy programs both within DOE, e.g., Civilian Nuclear Waste and Environmental Cleanup programs, and programs external to DOE, e.g. Privatization of uranium enrichment, and the Defense Nuclear Facilities Safety Board.

Michael Corradini is Wisconsin Distinguished Professor Emeritus of Nuclear Engineering in the Department of Engineering Physics at the University of Wisconsin-Madison. He served from 1995 to 2001 as Associate Dean for the College of Engineering and as Chair of Engineering Physics from 2001-2011. He has published widely in areas related to reactor technology and safety and transport phenomena in multiphase systems. In 1998, he was elected to the National Academy of Engineering. He was also served as a presidential appointee in 2002 and 2003 as the chairman of the Nuclear Waste Technical Review Board (a separate government agency). From 2004-2008, he served as a board member of the INPO National Nuclear Accreditation Board. In 2006, he was appointed to the NRC Advisory Committee on Reactor Safeguards. Most recently, he was appointed Chair of the Scientific Advisory Committee to the French Atomic Energy Agency. He began and served as the Director of the Wisconsin Energy Institute. He was the Co-Director of the recently released MIT Study: Future of Nuclear Power in a Carbon-constrained World.

Paul Wilson is the Grainger Professor of Nuclear Engineering and Chair of the University of Wisconsin-Madison's Department of Engineering Physics. His research interests focus on developing improved tools for computational modeling of complex nuclear energy systems, with applications in radiation shielding, nuclear waste management, nuclear non-proliferation and energy policy. Paul joined the University of Wisconsin-Madison as an assistant professor in August 2001 as part of the Energy Systems and Policy Hiring Initiative. Paul currently serves on the Board of Directors of the American Nuclear Society and as a board member of the INPO National Nuclear Accreditation Board. In addition to the research pursued by his Computational Nuclear Engineering Research Group (CNERG), Paul has served in a number of advisory and consultant roles. From 2001-2003, he was a member of the U.S. Department of Energy's Generation IV Technology Roadmap Committee. In 2010, he was engaged as a consultant to the CEA Saclay, ERC Petten, the Karlsruhe Institute of Technology, and the Blue-Ribbon Commission on America's Nuclear Energy Future.

Sarah Johnston is an Assistant Professor in the Department of Agricultural and Applied Economics at the University of Wisconsin-Madison. She joined the department in 2018 after spending one year as a postdoctoral fellow in the UW-Madison Economics Department. Her research studies on how energy policy affects firm investment decisions, and she focuses on applications in the electric power sector. She received a Ph.D. in economics from the University of Michigan in 2017 and a B.A. in economics from Dartmouth College in 2009.

Bruce Beihoff is a former Technical Director within the Grainger Institute for Engineering, College of Engineering, University of Wisconsin-Madison. As Technical Director specializing in Systems and Industrial Research Bruce manages projects and serves as principal investigators in the areas of Integrated Energy Systems, Distributed Power Systems, and Power Electronics and Electric Machines. Bruce spent 38 years in Industry as a principal engineers and Research Engineering director in major technology companies such as Black and Veatch, General Electric, Eaton Corporation, Rockwell International, Whirlpool Technologies. Bruce's research accomplishments have centered on the use of systems engineering and techno-economic analysis to solve complex energy and power conversion system challenges in the implementation of highly advanced products for the Utilities, Aerospace, Industrial, Automotive, Naval, and Data Processing applications. As part of his Industrial experience Bruce was involved as a program leader supporting Reactor controls and safety systems design of large- and small-scale electrical generation plants. Bruce holds 47 patents and has been awarded significant engineering honors by Eaton Corporation, Rockwell International, University of Wisconsin-Madison, and the International Counsel on Systems Engineering (INCOSE). Bruce holds a BS and MS from UW-Madison and University of Wisconsin-Milwaukee.

Scott Greene is an Associate Scientist in the Department of Electrical and Computer Engineering at the University of Wisconsin – Madison, affiliated with the Wisconsin Energy Institute (WEI). Prior to joining WEI in 2018, Scott spent over two decades as a consultant to electric utilities, energy trading companies, transmission operators, market operators, and generation companies. His project experience includes financial and physical risk analysis of fossil, nuclear, and renewable generation across five continents. His published works in the IEEE Power Engineering Society have been cited over one thousand times. Scott's current research involves optimal generation dispatch. Scott earned a BS in Mechanical Engineering at Cornell University and the MS and PhD in Electrical Engineering at the University of Wisconsin – Madison.

Greg Zacharski is an active-duty U.S. Navy Captain, currently the Professor of Naval Science, and Commanding Officer the Naval ROTC Unit, at the University of Wisconsin-Madison. A Surface Warfare Officer, he has served a progressive, 30-year career – both at sea and ashore. He managed the Navy's Shipbuilding budget from 2005 to 2007 and was Chief of Special Actions for the Chairman of the Joint Chiefs of Staff from 2012 to 2015 – where he coordinated global, non-kinetic military activities, liaising with the National Security Council and U.S. Intelligence Community. He was the Director of the Navy's Operational Energy Office from 2015 to 2017, creating and executing Navy Operational Energy policies, and assessing and resourcing operational energy investments (>$50M/yr) in R&D, and mature technologies, which enhance the persistence of combat capability for ships and aircraft. Most recently he established, and served as director for, the Navy's Foreign Investment Security Office, charged with assessing the potential risk or vulnerability investments may pose to the U.S. Navy's global logistics support enterprise, and serving also as the Navy representative to the Committee on Foreign Investment in the United States (CFIUS), for cases which could pose potential risk to national security.

Kathryn Biegel is a PhD student in the University of Wisconsin – Madison Engineering Physics Department, and a graduate researcher in the Argonne National Laboratory Nuclear Science and Engineering Division. Biegel's research focus is on the economics of nuclear energy, particularly the impact of construction cost and risk on the market viability of nuclear reactors as commercial products. Prior to beginning graduate studies, Biegel worked with utility companies on capital program planning and procurement projects as a client services manager at PowerAdvocate in Boston, after attaining a B.S. in Nuclear Science and Engineering from MIT.

Ryan Dailey is a PhD student in the Nuclear Engineering and Engineering Physics (NEEP) at the University of Wisconsin-Madison. He primarily focuses on research for advanced reactor development and deployment, alongside work in LWR safety using the reactor safety codes. He has been with the University of Wisconsin-Madison since 2015, when he started his undergraduate B.S. degree in nuclear engineering. Upon completion of his undergraduate studies in late 2019, Ryan completed his M.S. thesis on the development of two microreactor modeling methods for usage in a microgrid modeling software in support of this study.

Antara Khadria is a recent masters graduate from the University of Wisconsin-Madison (UW). She holds an MS in Electrical Engineering and an MS in Environment and Resources (E&R). Her E&R thesis research focused on analyzing the economic feasibility of low-carbon resources on supplying the thermal energy needs of the UW campus. As part of her graduate studies, she also completed the certificate in Energy Analysis and Policy (EAP) offered by the Nelson Institute for Environmental Studies. Prior to graduate studies, she worked as a research intern at the Indian Institute of Technology (IIT) Delhi. She holds a B.S. degree in Electronics and Communication Engineering from Manipal University, India.

Danjing Lei is a PhD student at Department of Agricultural and Applied Economics of University of Wisconsin-Madison since 2018. Her research focus is on environment, energy and climate change economics and policy. Prior to joining UW-Madison, Danjing was a master student of a dual-degree program jointly held by Tsinghua School of Environment and Yale School of Forestry and Environmental Studies. Her masters major was environmental science and engineering at Tsinghua and environmental management at Yale. She also holds a B.S. degree of environmental engineering when she graduated from Tsinghua in 2015.

Chumani Mokoena is a fourth year Nuclear Engineering undergraduate student at the University of Wisconsin Madison. He is interested in research related to the alternative applications of nuclear energy facilities to increase economic competitiveness of the underlying technology with alternative environmentally friendly energy sources. He was born and raised in South Africa prior to attending UW Madison for his Bachelor of Science. Upon completion of undergraduate studies in May 2021, he looks forward to continuing his education at the graduate level with specific focus on his research interests. Following his academic studies, he is hoping to return to South Africa and offer his expertise in the domestic nuclear industry.

James Parke received his MBA from the Wisconsin School of Business in 2020. Following a BS in Mechanical Engineering from Miami University (OH), he worked for four years in the manufacturing sector. He also has experience in the power sector, supporting GE Power's interests in providing power to remote sites in South America, and in the IT sector supporting business analysis for IBM. Mr. Parke currently works in the automotive sector.

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Appendix M
Acknowledgements

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Mr. Tom Sowinski and Mr. Shane Johnson, DoE Office of Nuclear Energy

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Drs. Jess Gehin and David Shropshire, Idaho National Laboratory

Mr. Jeffrey Pollei, University of Wisconsin, Facilities Planning and Management

Dr. Greg Nemet, University of Wisconsin

Mr. Kevin Carroll, previously Director, DoE Sustainability Performance Office

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Appendix N
End Notes

i 10/23/19, INL Statement of Work SOW-15544. Amended 10/24/19 to exclude DOD installations: e-mail from David Shropshire (INL) to Thomas Palmieri (UW)

ii There are many discussions of resilience in the recent literature. In this study we focus on an operational definition as it relates to government facilities. For a more general discussion that focuses on nuclear energy and includes a discussion of the technology design, the necessary organization, the system for controlling and dispatching electricity on a site, and the current socio-economic issues, see: https://www.world-nuclear-news.org/Articles/Speech-The-resilience-of-nuclear-power

iii A full listing of DOD documents relevant to resilience is found in the following link: https://www.acq.osd.mil/eie/IE/FEP_Policy_Program_Guidance.html
Office of the Assistant Secretary of Defense for Sustainment. Installation Energy Policy and Program Guidance.

iv https://www.acq.osd.mil/eie/Downloads/IE/DODI%204170.11%20-%20Change%201%20Effective%20March%2016%202016%20FINAL.pdf Part II. Definitions.

v https://www.law.cornell.edu/uscode/text/10/101

10 USC 101 (e) (6, 7, and 8) :

(6)Energy resilience.—
The term ”energy resilience” means the ability to avoid, prepare for, minimize, adapt to, and recover from anticipated and unanticipated energy disruptions in order to ensure energy availability and reliability sufficient to provide for mission assurance and readiness, including mission essential operations related to readiness, and to execute or rapidly reestablish mission essential requirements.

(7)Energy security.—
The term “**energy** security” means having assured access to reliable supplies of energy and the ability to protect and deliver sufficient energy to meet mission essential requirements.

(8)Military installation resilience.—
The term **military installation resilience**” means the capability of a military installation to avoid, prepare for, minimize the effect of, adapt to, and recover from extreme weather events, or from anticipated or unanticipated changes in environmental conditions, that do, or have the potential to, adversely affect the military installation or essential transportation, logistical, or other necessary resources outside of the military installation that are necessary in order to maintain, improve, or rapidly reestablish installation mission assurance and mission-essential functions.

vi https://www.acq.osd.mil/eie/Downloads/IE/DODI%204170.11%20-%20Change%201%20Effective%20March%2016%202016%20FINAL.pdf Page 15 (c)

vii https://www.acq.osd.mil/eie/Downloads/IE/IEP%20Policy_May302018.pdf

viii https://archive.ll.mit.edu/mission/engineering/Publications/TR-1216.pdf

ix https://www.wbdg.org/FFC/DOD/UFC/ufc_3_540_01_2014_c2.pdf

DoD Unified Facilities Criteria (UFCV) Engine-Driven Generator Systems for Prime \1\ and Standby Power Applications \1\ p 4-5 sec 2-3. Also Army secure critical missions – 14 days

[x] The Camp Fire started on November 8, 2018 (https://en.wikipedia.org/wiki/Camp_Fire_(2018)) .

(https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-restoration.page?WT.pgeac=Wildfire_EmergencyResponse-Restoration) November 8 to Dec 31 is 53 days.

According to PG&E, "Power was restored to the majority of electric customers in Paradise who were able to receive service by Sunday, December 16. We anticipate being able to restore power to nearly all Butte County customers who can receive electric service by the end of December 2018, weather permitting.

[xi] This is important. Current outages on Government installations are often due to problems within the installation: failures in switching gear, failures in generators that service specific buildings, etc. A micro grid implies an upgrade of the power generation and distribution system within the installation so that facility managers can view their entire site as an island, where the a few on-site generators can service the entire installation.

[xii] The data is accessed through several drop-down menus.

https://ctsedwweb.ee.doe.gov/CTSDataAnalysis/ComplianceOverview.aspx
Choose Covered facility annual footprint

https://ctsedwweb.ee.doe.gov/CTSDataAnalysis/Reports/PublicAgencyReport_CoveredFacilityAnnualFootprint.aspx
Select Fiscal year 2018. Then apply filter

[xiii] https://ctsedwweb.ee.doe.gov/Annual/Report/Report.aspx.
Then click on Table A8. In table A8 Click on 2018 and "apply".

[xiv] The data is accessed through several drop-down menus

To get to the data for a specific agency:

https://ctsedwweb.ee.doe.gov/CTSDataAnalysis/ComplianceOverview.aspx

Then click on "Publicly Disclosed Covered Facility Annual Footprint

Then select DOE (for example) as the agency

Select Fiscal year 2018. Then apply filter

[xv] The data is accessed through several drop-down menus

https://ctsedwweb.ee.doe.gov/CTSDataAnalysis/ComplianceOverview.aspx

Click on "Covered facility Annual Footprint by State". In the disclaimer, click OK. Get to:

https://ctsedwweb.ee.doe.gov/CTSDataAnalysis/Reports/PublicGovernmentReport_CoveredFacilityAnnualFootprintByState.aspx

Click on Select - Fiscal year (drop-down) 2018. Then apply filter. Then Click on Alaska

[xvi] https://www.fedconnect.net/FedConnect/default.aspx?doc=89243218NNE000001&agency=DOE

Department of Energy Request for Information 89243218NNE000001 "Input on a Pilot Program for Microreactor Demonstration", September 13, 2018.

xvii https://gain.inl.gov/SiteAssets/Advanced%20Nuclear%20Directory/GAINAdvancedNuclearDirectory-SixthEdition_01.06.2021.pdf

xviii https://gain.inl.gov/SiteAssets/Micro-ReactorWorkshopPresentations/Attendees-18.June.2019(1).pdf

xix NRC (ADAMS) docket #99902046

https://adams.nrc.gov/wba/?data=(mode:sections,sections:(filters:(public-library:!t),options:(within-folder:(enable:!f,insubfolder:!f,path:%27%27)),properties_search_all:!(!(DocketNumber,eq,%2799902046%27,%27%27))))&qn=New&tab=advanced-search-pars&z=0

xx https://www.westinghousenuclear.com/Portals/0/new%20plants/evincitm/GTO-0001_eVinci_flysheet_RSB_03-2019_003.pdf?ver=2019-04-04-140824-613

xxi https://www.youtube.com/watch?v=Sh6BKKFxN_g

xxii http://www.holosgen.com/about-us-1-2/

xxiii https://gain.inl.gov/SiteAssets/Micro-ReactorWorkshopPresentations/Presentations/22-Filippone-HOLOS_DOE%20GAIN_6-18-2019.pdf

xxiv https://inis.iaea.org/collection/NCLCollectionStore/_Public/51/111/51111609.pdf?r=1 (page 213).

xxv https://www.nuscalepower.com/benefits/simplified-design

xxvi https://gain.inl.gov/SiteAssets/Micro-ReactorWorkshopPresentations/Presentations/14-Marotta-MsNBMRWorkshop_June2019.pdf

xxvii https://www.nrc.gov/reactors/new-reactors/col/aurora-oklo.html

xxviii https://www.u-battery.com/cdn/uploads/supporting-files/U-Battery_Prospectus_July2020_1.pdf

xxix https://ceaa-acee.gc.ca/050/documents/p80182/130911E.pdf
Description of the Micro-Modular-Reactor Project at Chalk River; GFP; 2019

xxx https://x-energy.com/reactors/xe-100.

xxxi https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Report-Cost-Competitiveness-of-Micro-Reactors-for-Remote-Markets.pdf

xxxii MIT Study on Future of Nuclear Power, 2018 http://energy.mit.edu/research/future-nuclear-energy-carbon-constrained-world/

xxxiii https://www.ieee-pes.org/images/files/pdf/IEEE%20QER%20Report%20September%205%202014%20HQ.pdf.

xxxiv https://www.nrel.gov/docs/fy19osti/67821.pdf

xxxv https://www.wbdg.org/ffc/nist/criteria/nistir-85-3273-33
NISTIR 85-3273-34 Energy Price Indices and Discount Factors for Life-Cycle Cost Analysis – 2019 Annual Supplement to NIST Handbook 135

xxxvi https://www.homerenergy.com/

xxxvii https://madison.com/wsj/news/local/ask/just-ask-us/just-ask-us-how-many-buildings-make-up-uw-madisons-campus/article_ec1c076d-508b-5c96-b246-96710467ccfc.html [xxxviii] https://www.nrc.gov/docs/ML1536/ML15364A497.pdfNUREG-0980, Vol.1, No.11, 2015;

[xxxix] https://clearpath.org/our-take/one-of-worlds-largest-energy-consumers-embracing-advanced-nuclear/

[xl] https://docs.house.gov/meetings/SY/SY20/20150729/103833/HHRG-114-SY20-20150729-SD009.pdf
Memorandum by T.Garvey to House Committee on Science, Space and Technology, "NRC Licensing of Proposed DOE Nuclear Facilities", July 20, 2015.

[xli] https://www.energy.gov/ne/nuclear-reactor-technologies/versatile-test-reactor

[xlii] 10 CFR Part 50 https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/index.html

[xliii] The applicant can also submit a complete Safety Analysis Report (SAR) at the CP stage. This allows for one hearing where the OL is issued if the facility is built substantially as depicted in the SAR.

[xliv] 10 CFR Part 52 https://www.nrc.gov/reading-rm/doc-collections/cfr/part052/index.html

[xlv] There is an optional hearing prior to fuel load limited to the scope of NRC inspections, testing, analysis and acceptance criteria (ITAAC) https://www.nrc.gov/reactors/new-reactors/oversight/itaac-hearings.html

[xlvi] https://www.congress.gov/115/plaws/publ439/PLAW-115publ439.pdf

[xlvii] Draft Regulatory Guide, DG-1353, April 2019
https://www.nrc.gov/docs/ML1831/ML18312A242.pdf

[xlviii] Regulatory Guide, RG 1.233, June 2020
https://www.federalregister.gov/documents/2020/06/09/2020-12402/guidance-for-a-technology-inclusive-risk-informed-and-performance-based-methodology-to-inform-the

[xlix] Oklo Reactor Application, 2020
https://www.nrc.gov/reactors/new-reactors/col/aurora-oklo/public-meetings/2020.html

[l] NIST Safety Analysis Report, NISTIR-7102
https://www.nrc.gov/docs/ML0411/ML041120201.pdf

[li] https://www.nrc.gov/docs/ML1922/ML19228A263.pdf

[lii] SECY-10-0034 Part 1 and Part 2, March 2010
https://www.nrc.gov/docs/ML0932/ML093290268.pdf

[liii] https://www.nrc.gov/docs/ML1916/ML19163A168.pdf
NRC Staff Draft Commission Paper, "Population-related Siting Consideration for Advanced Reactors, 2019

[liv] ACRS Letter on Clinch River Early Site Permit;
https://www.nrc.gov/docs/ML1900/ML19009A286.pdf

[lv] Regulatory Guide 4.7, https://www.nrc.gov/docs/ML1218/ML12188A053.pdf

[lvi] Prototype Nuclear Plant,
https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-0002.html

"*Prototype plant* means a nuclear reactor that is used to test design features, such as the testing required under § 50.43(e). The prototype plant is similar to a first-of-a-kind or standard plant design in all features and size, but may include additional safety features to protect the public and the plant staff from the possible consequences of accidents during the testing period."

lvii NEICA; https://www.govinfo.gov/app/details/PLAW-115publ248

lviii NRIC; https://www.energy.gov/ne/articles/energy-department-launches-new-demonstration-center-advanced-nuclear-technologies

lix http://energy.mit.edu/research/future-nuclear-energy-carbon-constrained-world/
MIT Report, Future of Nuclear Power in a Carbon-constrained World, Chapter 5 pp. 138-139

lx NPUF Draft Rule https://www.govinfo.gov/content/pkg/FR-2017-03-30/pdf/2017-06162.pdf

lxi https://www.nrc.gov/info-finder/nonpower/shine-medical-tech.html

lxii https://www.nrc.gov/docs/ML1922/ML19228A263.pdf
M.Nichol et al, "Micro-Reactor Regulatory Issues", Nuclear Energy Institute White Paper, Nov. 2019

lxiii https://www.gsa.gov/real-estate/environmental-programs/energy-water-conservation/areawide-public-utility-contracts/for-federal-agency-customers

lxiv https://www.law.cornell.edu/uscode/text/10/2913

lxv https://www.energy.gov/eere/femp/energy-savings-performance-contract-energy-sales-agreements

lxvi NIST used this approach. See:
https://www.energy.gov/sites/prod/files/2019/09/f67/cs-espc-esa.pdf

Note also that it is possible for institutions to "bundle" their initiatives in order to qualify for an ESCP. While there may be no direct energy savings, if an institution then adds upgrades to air conditioning units or makes other energy saving changes, the entire package may end up with an energy saving and may qualify for an ESPC.

lxvii https://www.law.cornell.edu/uscode/text/42/8287

42 U.S. Code § 8287. Authority to enter into contracts

(a) In general (1) The head of a Federal agency may enter into contracts under this subchapter solely for the purpose of achieving energy savings and benefits ancillary to that purpose. Each such contract may, notwithstanding any other provision of law, be for a period not to exceed 25 years. Such contract shall provide that the contractor shall incur costs of implementing energy savings measures, including at least the costs (if any) incurred in making energy audits, acquiring and installing equipment, and training personnel, in exchange for a share of any energy savings directly resulting from implementation of such measures during the term of the contract.

(2) (E) Funding options.—In carrying out a contract under this subchapter, a Federal agency may use any combination of—

(i)appropriated funds; and

(ii) private financing under an energy savings performance contract.

lxviii https://www.seia.org/initiatives/solar-investment-tax-credit-itc#:~:text=26%20percent%20for%20projects%20that,to%20a%20permanent%2010%20percent

[lxix] https://programs.dsireusa.org/system/program/detail/734

[lxx] 26 USC 45J: https://www.law.cornell.edu/uscode/text/26/45J

[lxxi] https://crsreports.congress.gov R44852

Congressional Research Service. The Value of Enrgy Tas Incentives for Different types of Energy Resources (2019)

[lxxii] https://www.law.cornell.edu/uscode/text/16/chapter-46

[lxxiii] https://www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf

[lxxiv] https://www.scientificamerican.com/article/cost-of-carbon-pollution-pegged-at-51-a-ton/#:~:text=Contributing%20to%20climate%20change%20is,to%20about%20%2451%20per%20ton.

[lxxv] https://archive.epa.gov/epa/cleanpowerplan/fact-sheet-clean-power-plan-opportunities-nuclear-power.html#:~:text=The%20Clean%20Power%20Plan%20(CPP,role%20in%20America's%20energy%20mix.&text=EPA%20expects%20nuclear%20power%20to,their%20Clean%20Power%20Plan%20goals.

[lxxvi] https://www.eenews.net/stories/1063724547

[lxxvii] There are currently about 32 Government owned Enterprises https://en.wikipedia.org/wiki/State-owned_enterprises_of_the_United_States

[lxxviii] https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Report-Cost-Competitiveness-of-Micro-Reactors-for-Remote-Markets.pdf (page 11).

[lxxix] https://www.nae.edu/239267/Chasing-Cheap-Nuclear-Economic-TradeOffs-for-Small-Modular-Reactors -Jessica R. Lovering & Jameson R. McBride.

[lxxx] https://www.defense.gov/Newsroom/Releases/Release/Article/2105863/dod-awards-contracts-for-development-of-a-mobile-microreactor/

"The engineering design phase of Project Pele will continue for up to two years, after which the DOD will make an assessment on whether a microreactor capable of meeting necessary safety requirements is feasible."

[lxxxi] https://www.energy.gov/ne/nuclear-reactor-technologies/advanced-reactor-demonstration-program

[lxxxii] https://www.congress.gov/116/crpt/srpt102/CRPT-116srpt102.pdf page 101

[lxxxiii] https://www.energy.gov/ne/downloads/infographic-advanced-reactor-demonstration-program

[lxxxiv] https://www.terrapower.com/terrapower-and-ge-hitachi-nuclear-energy-launch-natrium-technology/

[lxxxv] https://x-energy.com/reactors/xe-100

[lxxxvi] https://www.energy.gov/ne/nuclear-reactor-technologies/advanced-reactor-demonstration-program

[lxxxvii] https://www.energy.gov/ne/downloads/infographic-advanced-reactor-demonstration-program

[lxxxviii] https://www.energy.gov/ne/downloads/infographic-advanced-reactor-demonstration-program

[lxxxix] DOE 2021 Congressional Budget Justification. Vol 3, Part 2, page 71

[xc] DOE 2021 Congressional Budget Justification. Vol 3, Part 2, page 28.

[xci] DOE 2021 Congressional Budget Justification. Vol 3, Part 2, page 34.

[xcii] https://navalnuclearlab.energy.gov/about-us/knolls-atomic-power-laboratory/

[xciii] https://navalnuclearlab.energy.gov/about-us/bettis-atomic-power-laboratory/

[xciv] https://www.directives.doe.gov/news/0481.1d-new

[xcv] https://www.nuscalepower.com/about-us/doe-partnership

[xcvi] https://www.directives.doe.gov/directives-documents/400-series/0413.3-EGuide-04-admchg1/@@images/file

[xcvii] https://www.directives.doe.gov/directives-documents/400-series/0413.3-EGuide-04-admchg1/@@images/file
DOE G 413.3-4A. See Figure 1, page 4.

[xcviii] https://aris.iaea.org/

[xcix] DOE 2021 Congressional Budget Justification. Vol 3, Part 2, page 34.

[c] https://www.energy.gov/technologytransitions/downloads/doe-public-private-consortia

[ci] https://nric.inl.gov/

[cii] Energy Policy Act of 2005 - PL 109-58 - Subtitle I – Research Administration and Operations.

Sec. 988. Cost sharing.

(a) APPLICABILITY …. In carrying out a research, development, demonstration, or commercial application program or activity … the Secretary shall require cost-sharing in accordance with this section.

(b) RESEARCH AND DEVELOPMENT.-
(1) IN GENERAL … The Secretary shall require not less than 20 percent of the cost of a research or development activity described in subsection (a) to be provided by a non-Federal Source.
(3) REDUCTION. - The Secretary may reduce or eliminate the requirement of paragraph (1) for a research and development activity of an applied nature if the Secretary determines that the reduction is necessary and appropriate.

(c) DEMONSTRATION AND COMMERCIAL APPLICATION.
(1) IN GENERAL. - …the Secretary shall require that not less than 50 percent of the cost of a demonstration or commercial application activity described in subsection (a) to be provided by a non-Federal source.
(2) REDUCTION OF NON-FEDERAL SHARE.- The Secretary may reduce the non-Federal share required under paragraph (1) if the Secretary determines that reduction to be necessary and appropriate, taking into consideration any technological risk relating to the activity.

[ciii] https://www.energy.gov/ne/initiatives/funding-opportunities

[civ] http://acqnotes.com/wp-content/uploads/2014/09/CRS-DoD-Use-of-Other-Transaction-Authority-Background-Analysis-and-Issues-for-Congress-22-Feb-2019.pdf. See Appendix A. Legislative History.

[cv] http://acqnotes.com/wp-content/uploads/2014/09/CRS-DoD-Use-of-Other-Transaction-Authority-Background-Analysis-and-Issues-for-Congress-22-Feb-2019.pdf.
See Appendix B. Non-DOD Federal Agencies…

[cvi] https://www.law.cornell.edu/uscode/text/10/2371

10 USC Sec 2371(a) Additional Forms of Transactions Authorized.—

The Secretary of Defense and the Secretary of each military department may enter into transactions (other than contracts, cooperative agreements, and grants) under the authority of this subsection in carrying out basic, applied, and advanced research projects.

[cvii] https://www.law.cornell.edu/uscode/text/10/2371b

10 USC Sec 2371b (a)AUTHORITY.- …or any other official designated by the Secretary of Defense may, under the authority of section 2371 of this title, carry out prototype projects that are directly relevant to enhancing the mission effectiveness of military personnel and the supporting platforms.

10 USC Sec 2371b (b)(2) To the maximum extent practicable, competitive procedures shall be used when entering to agreements to carry out the prototype projects under subsection (a).

[cviii] https://www.law.cornell.edu/uscode/text/10/2371b
10 USC 2371b. (d) Appropriate Use of Authority.—

(1) The Secretary of Defense shall ensure that no official of an agency enters into a transaction (other than a contract, grant, or cooperative agreement) for a prototype project under the authority of this section unless one of the following conditions is met:

(A) There is at least one nontraditional defense contractor or nonprofit research institution participating to a significant extent in the prototype project.

(B) All significant participants in the transaction other than the Federal Government are small businesses (including small businesses participating in a program described under section 9 of the Small Business Act (15 U.S.C. 638)) or nontraditional defense contractors.

(C) At least one third of the total cost of the prototype project is to be paid out of funds provided by sources other than the Federal Government.

[cix] https://www.dau.edu/guidebooks/Shared%20Documents/Other%20Transactions%20(OT)%20Guide.pdf

[cx] See links:

https://aaf.dau.edu/ot-guide/myths/

https://www.nationaldefensemagazine.org/articles/2018/9/27/ethics-corner-other-transaction-authority---big-rewards-risks

[cxi] http://acqnotes.com/wp-content/uploads/2014/09/CRS-DoD-Use-of-Other-Transaction-Authority-Background-Analysis-and-Issues-for-Congress-22-Feb-2019.pdf

[cxii] https://www.nrel.gov/docs/fy19osti/67821.pdf

[cxiii] https://www.lazard.com/media/450773/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

[cxiv] https://www.nrel.gov/analysis/tech-lcoe-re-cost-est.html

[cxv] http://www.pes-gm.org/2012/

[cxvi] A. C. Kadak, "A COMPARISON OF ADVANCED NUCLEAR TECHNOLOGIES," p. 112. NY,NY 2017 https://energypolicy.columbia.edu/sites/default/files/A%20Comparison%20of%20Nuclear%20Technologies%20033017.pdf

[cxvii] We abstract from the manager's ability to change this value over time; given the setup of the problem, the manager would have no incentive to do so.

[cxviii] https://www.nrc.gov/docs/ML1915/ML19155A173.pdf -- Sowder, A., "Uranium Oxycarbide (UCO) Tristructural Isotropic (TRISO) Coated Particle Fuel Performance: Topical Report EPRI-AR-l (NP)" May 2019

[cxix] https://www.nrc.gov/docs/ML1825/ML18253A109.pdf
See page 11. Van Staden, M. "Technology Overview" X-Energy Presentation to USNRC, March 2018.

[cxx] ANL Fuel Cycle Calculator, https://cnpce.ne.anl.gov/cgi-bin/qnecost?select=home https://www.anl.gov/nse/advanced-fuel-cycle-cost-basis-report

[cxxi] H.W.Levi, M.Benedict, T.H.Pigford, Nuclear Chemical Engineering, McGraw-Hill, 1981

[cxxii] https://www.aerialapplications.com/blog/how-much-does-a-service-outage-really-cost-an-electric-company

https://microgridknowledge.com/power-outage-costs-electric-reliability/ Power Outage Costs and the Value of Electric Reliability"