# Purchasing Power Produced by Small Modular Reactors: Federal Agency Options

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This Report does not represent the views of DOE, and no official endorsement should be inferred. Additionally, this Report is not intended to provide legal advice, and readers are encouraged to consult with an attorney familiar with the applicable federal and state requirements prior to entering into any agreements for the purchase of power.

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# Purchasing Power Produced by Small Modular Reactors: Federal Agency Options

## CONTENTS



## APPENDICES



## FIGURES

# EXECUTIVE SUMMARY

The purpose of this Report is to provide guidance to federal agencies on procuring power generated by small modular reactors ("SMRs") in accordance with existing federal authorities. By following this guidance, federal agencies can take advantage of the opportunity to purchase highly reliable carbon-free power and provide support for financing the development of the initial SMRs.

After years of development, SMRs are close to obtaining Nuclear Regulatory Commission ("NRC") regulatory approval. DOE has identified that these small nuclear power plants will "play an important role in addressing the energy security, economic and climate goals of the U.S. if they can be commercially deployed within the next decade," making it a primary element of the DOE Office of Nuclear Energy's Nuclear Energy Research and Development Roadmap.[1]

Private industry is leading the development of SMRs. There is wide-spread recognition that the risks presented by introducing this new technology in the electric power sector will require public-private risk sharing to achieve commercial deployment. In October 2016, the Nuclear Energy Institute introduced "SMR Start," an advocacy program calling for public-private partnerships to advance commercial deployment of SMRs.[2] Key elements of SMR Start include the extension of production tax credits ("PTCs") established under the Energy Policy Act of 2005 ("EPACT"), DOE loan guarantees established under Title XVII of EPACT, and Power Purchase Agreements ("PPAs").

Given the magnitude of power purchases by federal users, federal PPAs have long been cited as a meaningful method to spur the siting and development of power projects using innovative technologies. By providing a contractual commitment to purchase power from a plant, certain business risks associated with the project are reduced, thereby improving the financial profile of the project for private investors. PPAs may be attractive from a public policy perspective because: (i) power supply is essential to the day-to-day operations of federal facilities and represents an expense that will be funded regardless of the source of supply, and (ii) purchases under a PPA would align the federal government's energy expenditures with federal policy objectives under a near budget neutral profile. However, PPAs have been difficult to implement in practice. Federal legal authorities for entering into long-term contracts, along with budget scoring rules, have made PPAs an appealing yet elusive option for advancing policy objectives.

Several federal agencies have expressed interest in purchasing electric power produced by an SMR. However, there is a myriad of complex regulations and processes to navigate, making it very challenging to implement PPAs on a broad scale to support a policy outcome. Generally, federal agencies can enter into PPAs to obtain power from an SMR (either from a utility purchasing power from an SMR developer or from an SMR developer directly) under the United States General Services Administration's ("GSA") authority set forth in 40 U.S.C. § 501 (subject to applicable federal and state requirements relating to the provision of electricity). However, this GSA authority is currently limited to a maximum of ten (10) years, and given the high up-front costs associated with the development of SMRs, a longer-term power purchase contract would better facilitate financing of the SMR. Longer term PPAs are challenging for federal agencies and, unless new legislation is enacted, longer term PPAs are only an option in limited circumstances for those federal agencies located within the service territory of certain Power Marketing Administrations ("PMAs"), such as the Western Area Power Administration ("WAPA") (which can purchase power for up to 40 years under certain circumstances), and under certain Department of Defense ("DOD") authorities (such as 10 U.S.C. § 2922a which permits DOD to purchase power for up to 30 years under certain circumstances).

This Report begins with background information intended to familiarize the reader with the benefits and challenges offered by SMRs (Chapter 1) and the current state of the United States power sector (Chapter 2). Next, this Report identifies the primary financing considerations for energy projects (Chapter 3). An overview of current legal authorities federal agencies utilize to purchase power, including those legal authorities that are most applicable to power purchases from an SMR, are identified (Chapter 4). This Report next identifies considerations federal agencies evaluate when making power purchase decisions (Chapter 5). Finally, this Report concludes by applying the principles outlined in the first five chapters to a notional project (Chapter 6) and offers a roadmap of key decision points for federal agencies exploring purchasing power from an SMR (Chapter 7).

Generally, developing SMRs will likely require long-term financing for terms of 30 years or more; accordingly, the SMR project developer (the borrower) and any lenders will want to know that any high volume purchasers of the power that will be produced will continue purchasing the power for the duration of the loan term. Thus, the sellers of the power (utilities and SMR developers) are exploring how to enter into contracts with a term longer than ten (10) years with federal agencies and other large power purchasers.

As compared to other power sources, SMRs may offer the following benefits, each of which are explained in more detail in Appendix A:

- Carbon-free baseload power
- Enhanced safety
- Modularity
- Lower cost
- Scalability
- Improved energy security
- Integration of renewables
- Siting flexibility
- Small land requirements
- Process heat
- International export opportunities
- Reduced fuel risk

In regions of the country serviced by WAPA, WAPA and a federal agency that wants to purchase power generated by an SMR can negotiate an Interagency Agreement under which WAPA, using its legal authorities, agrees to enter into a PPA with the seller of the power (utility or SMR developer) for a maximum term of 40 years. WAPA's contract with the seller of the power will require the seller of the power to deliver the power to the federal agency, which will then be required under the Interagency Agreement to pay for the power during the duration of the PPA term. Additionally, federal agencies in other regions of the United States may be able to access alternate authorities under other PMAs; however, a discussion of their authorities are outside the scope of this Report. In other areas of the country not served by a PMA or by a PMA with extended contracting authority, legislation would need to be enacted to permit longer term power purchases (except in limited circumstances where DOD authorities may apply).

Power purchase decisions are complicated and important choices. When evaluating whether to purchase power from an SMR, federal off-takers will want to consider its demand profile, understand performance risks of its power source, and perform a financial impact analysis. Likewise, investors will evaluate elements applicable to all power projects (such as technology stability, contract term, and tax advantages), as well as additional concerns raised by the unique and new technology offered by SMRs (such as regulatory approvals, safety, and reliability).

Federal agencies can purchase power from a power producer or from a utility, subject to applicable federal and state requirements. Most federal agencies purchase power from the local utility in the area or through arrangements directly with power producers or PMAs, such as WAPA. In accordance with 40 U.S.C. § 591(a), federal agencies cannot purchase electricity in a manner inconsistent with state law governing the provision of electric utility service.

The Utah Associated Municipal Power Systems ("UAMPS") Carbon Free Power Project (the "Idaho SMR Project" or "CFPP") involves an SMR being developed by NuScale Power, LLC ("NuScale"), which is currently planned to be developed on land owned by the Department of Energy ("DOE") at the Idaho National Laboratory ("INL"). UAMPS has 45 members which are municipal and other public power utilities in eight states. Currently, the Idaho SMR Project structure contemplates that the power from the SMR will be sold to UAMPS' member utilities, as well as other power purchasers (non-members). Thus, subject to applicable federal and state laws, federal agencies could purchase the power produced by the SMR directly from UAMPS or one of the member or non-member utilities purchasing power from UAMPS.

As further detailed in Chapter 6, for the Idaho SMR Project, scenarios exist for federal agency customers to directly enter into a 10 year PPA under the GSA authority with UAMPS or a utility purchasing power from UAMPS, or enter into an Interagency Agreement with WAPA and for WAPA, in turn, to enter into a longer term PPA with UAMPS or a utility purchasing power from UAMPS.

As depicted in Figure 1, there are several different scenarios through which a federal agency could contract to purchase power produced by the SMR in the Idaho SMR Project. These scenarios are as follows:

*Most Likely Options Contracting Between a Federal Agency and a Utility:*

1. **Option 1: Federal Agency Uses GSA Authority to Contract with a Utility.** Either directly (if DOD or DOE), through GSA, or with delegated authority obtained from GSA, a federal agency can enter into a direct agreement with a utility (either a member of UAMPS or a non-member purchasing power produced by the SMR from UAMPS) to purchase power produced by the SMR for a maximum of ten (10) years. This is likely the most typical method of contracting that will be used by federal agencies, but utilities will likely prefer longer-term agreements outlined below.

2. **Option 2: Federal Agency Collaborates with WAPA to Enter into a Longer-Term PPA with a Utility.** For those federal agencies located within WAPA's service territory, the federal agency and WAPA could enter into an Interagency Agreement. Pursuant to the Interagency Agreement, the federal agency would pay a negotiated charge to WAPA for WAPA to develop a PPA with the utility (either a member of UAMPS or a non-member

purchasing power produced by the SMR from UAMPS) on behalf of the federal agency. The Interagency Agreement would identify that the federal agency is responsible for all costs charged under the PPA, as well as a negotiated annual charge for contract administration. WAPA would also enter into a PPA with the utility with a maximum term of 40 years. For federal agencies located in other PMA jurisdictions, this option can be explored.

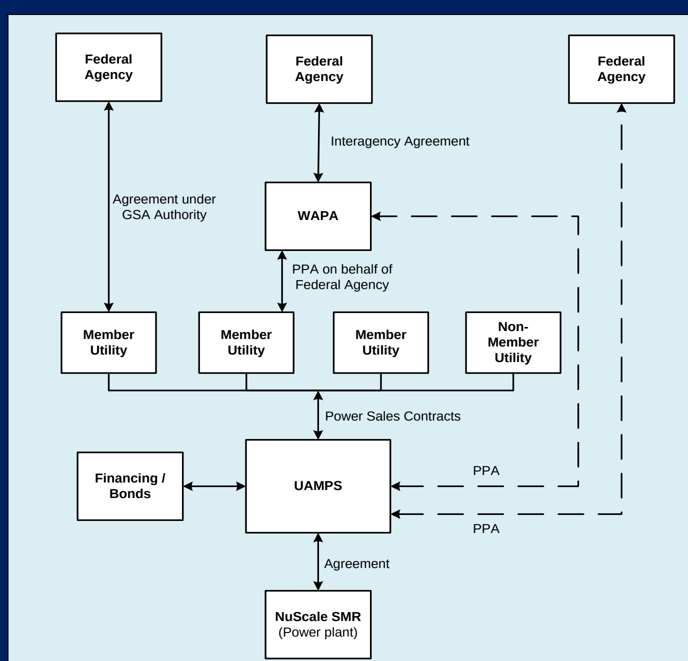
*Additional Options Contracting Between a Federal Agency and UAMPS:*

3. **Option 3: Federal Agency Uses GSA Authority to Contract with UAMPS.** Either directly (if DOD or DOE), through GSA, or with delegated authority obtained from GSA, a federal agency can enter into a direct agreement with UAMPS to purchase power produced by the SMR for a maximum of ten (10) years.

4. **Option 4: Federal Agency Collaborates with WAPA to Enter into a Longer-Term PPA with UAMPS.** For those federal agencies located within WAPA's service territory, the federal agency and WAPA could enter into an Interagency Agreement. Pursuant to the Interagency Agreement, the federal agency would pay a negotiated charge to WAPA for WAPA to develop a PPA with UAMPS on behalf of the federal agency. The Interagency Agreement would identify that the federal agency is responsible for all costs charged under the PPA, as well as a negotiated annual charge for contract administration. WAPA would also enter into a PPA with UAMPS with a maximum term of 40 years. For federal agencies located in other PMA jurisdictions, this option can be explored.

**Figure 1**

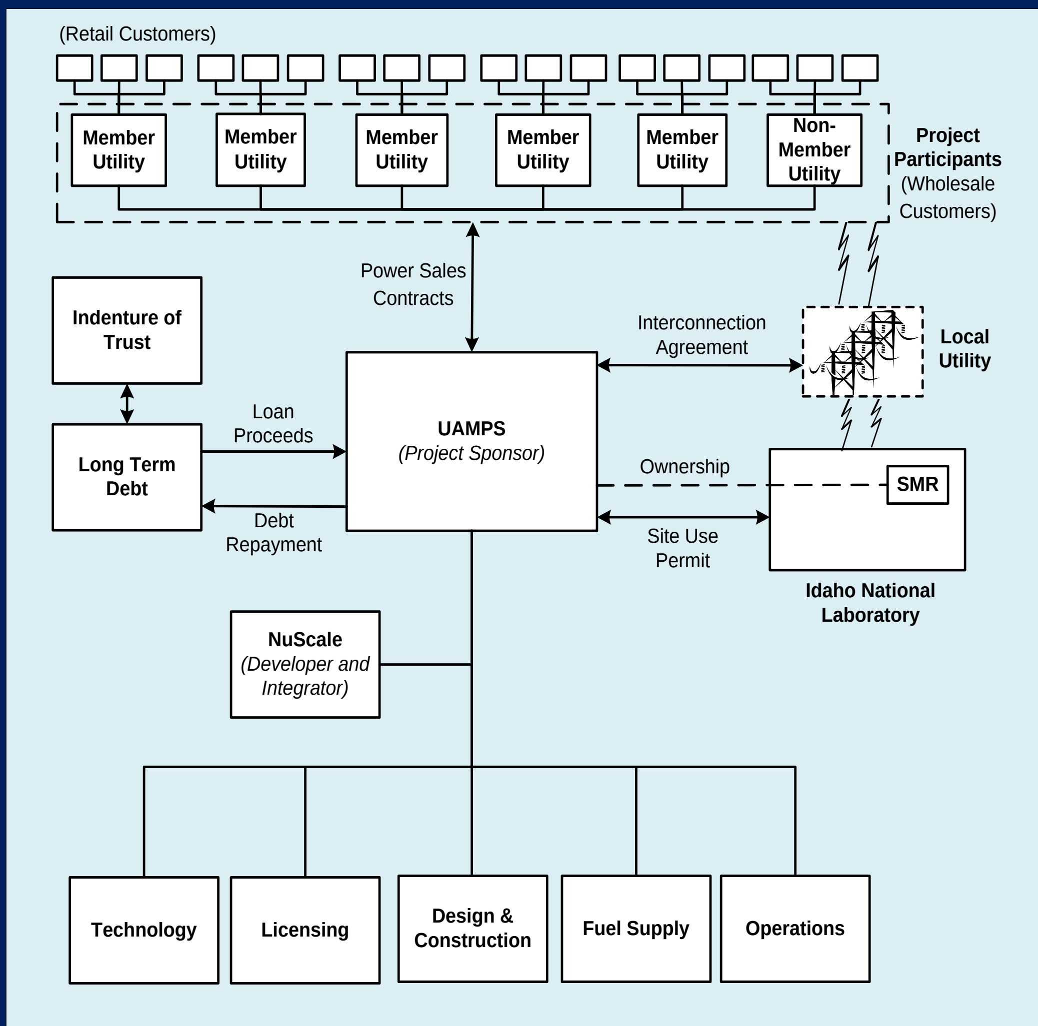
**Potential Ways to Involve Federal Customers in the Idaho SMR Project**



As further detailed in Chapter 6 and depicted in Figure 2, there are many agreements and parties involved in a potential financing structure for the Idaho SMR Project.

**Figure 2**

**Potential Financing Structure for the Idaho SMR Project**




As contemplated, the financing structure of the Idaho SMR Project provides strong credit fundamentals and should facilitate the development and financing of the Idaho SMR Project at a long-term fixed interest rate. Importantly, this structure should improve the competitiveness of the Idaho SMR Project relative to other sources of baseload power. However, a number of challenges are introduced by this first of a kind project:

- **Licensing Risk:** Early in the Idaho SMR Project development process, the Idaho SMR Project will need to obtain a Combined Construction and Operating License ("COL") from the NRC. In order to receive a COL, the Idaho SMR Project will have to invest millions of dollars in early stage development cost. Under the plan, these expenditures will not commence until the Power Sales Contracts have been executed. Therefore, the risk from the COL Application ("COLA") process will fall upon the participating members of UAMPS. Failure to receive a COLA will result in financial losses for UAMPS, and such losses will be incurred prior to plant construction. There is also uncertainty of completion, because the NRC will need to provide approvals before the facility can begin operations. At this stage, the Idaho SMR Project could experience delays in production, adding expense to UAMPS and its subscribers.

- **Technology Risk:** If implemented, the Idaho SMR Project will be the first SMR sited and constructed in the United States. The technology risk associated with this first-of-a-kind project represents a key challenge for the project sponsor to overcome. Idaho SMR Project lenders will need to become comfortable with the Idaho SMR Project's engineering and construction plans, as well as plans for long-term operations. In addition, the licensing risk introduced by an untested regulatory process could introduce delays in the initiation of commercial operations. These considerations will need to be addressed in the Idaho SMR Project's financing plan to ensure adequate protection to Idaho SMR Project lenders.

- **First of a Kind Costs:** A key benefit of SMRs is that component parts and assemblies could be manufactured in a factory and shipped to the Idaho SMR Project site. Over time, this could introduce significant economies of scale into the plant construction process. However, the Idaho SMR Project will not benefit from these economies as it is the first SMR to be built, and thus faces First of a Kind ("FOAK") costs, which are higher than would be expected over the long run as costs decrease.[3]

- **Uncertainty in Long-Term Energy Markets:** While it is widely recognized that the aging fleet of coal fired power projects and nuclear generating stations will need to be replaced over the next decade, the current conditions in the energy markets have introduced long-term uncertainties. In particular, the current low-cost of natural gas makes it challenging for other sources of baseload power to be competitive on price alone. While the historic volatility of natural gas is well recognized, the abundant supply of natural gas and its current cost profile make it the most economic option at this time. There is considerable uncertainty over the changes in demand for natural gas and the market equilibrium that will be achieved over the long-term.

- **Development Timeline:** Given the need to find replacement sources of baseload power, the uncertainty over the Idaho SMR Project's development timeline may introduce challenges to Project Participants. Specifically, Project Participants require a new source of baseload power to be commissioned by 2025, and thus require a precise estimate of the expected commercial operation date of the Idaho SMR Project. Since the Idaho SMR Project is subject to considerable uncertainly in respect to licensing, financing, and construction, this presents a challenge for all involved.

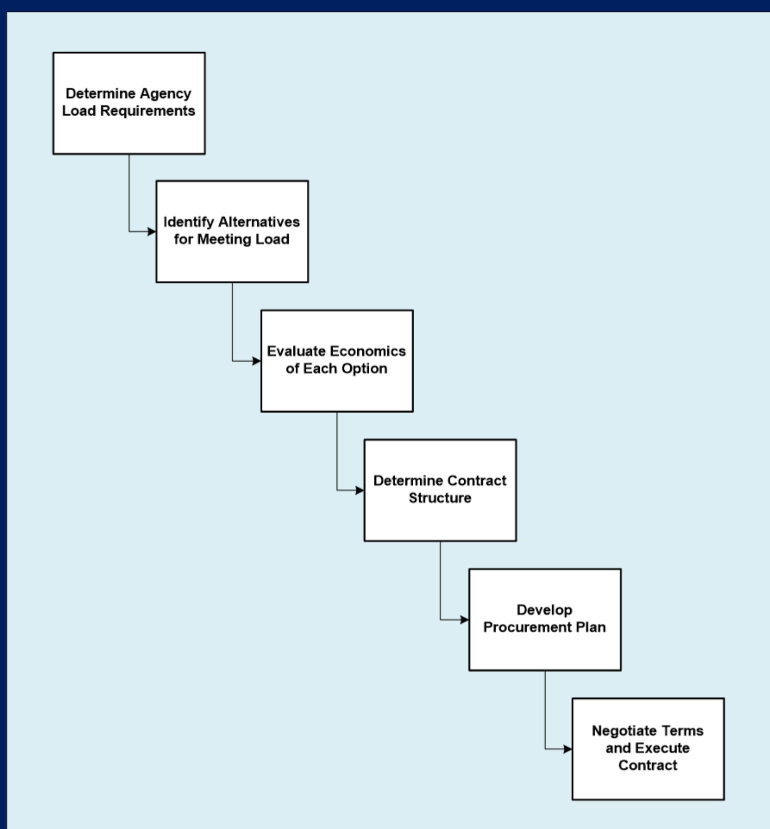
- **Production Tax Credits:** According to the Project Sponsor, the production tax credits that were introduced in EPACT are essential to making the Idaho SMR Project cost-competitive. However, for the Idaho SMR Project to benefit from the tax credits, the sunset date on the production task credits must be extended, and the Idaho SMR Project will need to be structured such that it can benefit financially from the tax credits. To do so, the Project Sponsor will need to allow private ownership of the plant or the amended legislation will need to allow the tax credits to benefit public power producers. Under either scenario, the Idaho SMR Project will require legislative actions.

- **DOE Loan Guarantee:** According to the Project Sponsor, the Idaho SMR Project may seek a DOE loan guarantee for part or all of the Idaho SMR Project financing. Given the new technology risk identified above, the DOE Title XVII Loan Guarantee Program represents an attractive and well-suited source of financing for the Idaho SMR Project. However, by statute, the DOE loan guarantee cannot benefit directly or indirectly from support provided by federal off-takers.[4] Therefore, the purchase of power from the Idaho SMR Project by a federal agency, such as a DOE laboratory, could impair the Idaho SMR Project's ability to obtain a DOE loan guarantee or limit the amount of the loan guarantee. This issue represents an important consideration in designing the Idaho SMR Project's financial structure.

This Report concludes with a roadmap federal agencies may wish to follow when making power purchase decisions that may involve an SMR. Key steps in the decision process are summarized in Figure 3 and described in Chapter 7.

**Figure 3**

**Federal Agency SMR Purchasing Roadmap**



# CHAPTER 1: INTRODUCTION AND BACKGROUND

## 1.1 Purpose of This Report

The purpose of this Report is to provide guidance to federal agencies on procuring power generated by SMRs in accordance with existing federal authorities. By following this guidance, federal agencies can take advantage of the opportunity to purchase highly reliable carbon-free power and provide support for financing the development of the initial SMRs.

After years of development, SMRs are close to obtaining NRC regulatory approval. DOE has identified that these small nuclear power plants will "play an important role in addressing the energy security, economic and climate goals of the U.S. if they can be commercially deployed within the next decade," making it a primary element of the DOE Office of Nuclear Energy's Nuclear Energy Research and Development Roadmap.[5]

Private industry is leading the development of SMRs. There is wide-spread recognition that the risks presented by introducing this new technology in the electric power sector will require public-private risk sharing to achieve commercial deployment. In October 2016, the Nuclear Energy Institute introduced "SMR Start," an advocacy program calling for public-private partnerships to advance commercial deployment of SMRs.[6] Key elements of SMR Start include the extension of PTCs established under the EPACT, DOE loan guarantees established under Title XVII of EPACT, and PPAs.

Given the magnitude of power purchases by federal users, federal PPAs have long been cited as a meaningful method to spur the siting and development of power projects using innovative technologies. By providing a contractual commitment to purchase power from a plant, certain business risks associated with the project are reduced, thereby improving the financial profile of the project for private investors. PPAs may be attractive from a public policy perspective because: (i) power supply is essential to the day-to-day operations of federal facilities and represents an expense that will be funded regardless of the source of supply, and (ii) purchases under a PPA would align the federal government's energy expenditures with federal policy objectives under a near budget neutral profile. However, PPAs have been difficult to implement in practice. Federal legal authorities for entering into long-term contracts, along with budget scoring rules, have made PPAs an appealing yet elusive option for advancing policy objectives.

Several federal agencies have expressed interest in purchasing electric power produced by an SMR. However, there is a myriad of complex regulations and processes to navigate, making it very challenging to implement PPAs on a broad scale to support a policy outcome.

This Report reviews key considerations and best practices for federal agencies seeking to purchase power from an SMR. This Report also reviews an SMR project currently under development – the Idaho SMR Project. The Idaho SMR Project provides an excellent case study for the application of federal PPAs. Using the Idaho SMR Project as an example, key issues are identified and actionable next steps are offered to assist federal agencies and other interested parties understand the benefits and limitations of purchasing power from an SMR.

Additionally, please note that the focus of this Report is on federal contracting authorities. However, it will also be necessary to evaluate applicable state laws prior to purchasing power, as federal agencies are prohibited from expending funds to purchase electricity in a manner inconsistent with state law governing the provision of electric utility service.[7]

## 1.2 The Small Modular Reactor Opportunity

The United States power sector will be defined in coming years by a need to increase the use of low-carbon power while ensuring that power is provided reliably and at low-cost. This is particularly relevant to baseload power. The term "baseload" refers to the minimum amount of electric power delivered or required over a given period of time at a steady rate.[8] Baseload power sources are power stations which can consistently generate the electrical power needed to satisfy this minimum demand.[9] The need to provide an adequate supply of baseload power will introduce challenges to the aging coal-fired power plants and nuclear generation stations. The Energy Information Agency ("EIA") estimates that coal power output will decline by 32 percent from 2015 to 2040, largely due to federal targets for carbon emission reduction[10] – unless those targets are repealed. EIA expects output from nuclear generation to remain largely constant through 2040, as some older plants are retired and some new plants come online.[11] Carbon emission targets are also expected to drive growth in renewable electricity output (mostly from intermittent solar and wind plants), growing by 99 percent from 2015 to 2030 and by 152 percent from 2015 to 2040.[12]

The expected growth of intermittent renewable energy will not replace coal and nuclear plants as baseload power sources. Relying on natural gas power plants to replace retired coal plants would help reduce carbon emissions noticeably relative to today's coal-heavy generation portfolio, but natural gas power plants do nonetheless release significant amounts of carbon.[13]

As baseload power plants are going off-line, there is a need for newly constructed power sources. Environmental considerations are driving consumers to look towards clean energy options. However, renewable power sources are not as reliable as traditional power stations, and thus, ill-suited sources of baseload power.[14] Hence, there is an opportunity for an environmentally friendly, reliable, and fast-responding power source.

The International Atomic Energy Agency ("IAEA") defines a small nuclear reactor as any reactor with an output of 300 megawatts electric ("MWe") or less.[15] Therefore, an SMR is any small nuclear reactor comprised of components, or modules, that are factory-fabricated and transported to a nuclear power plant location for on-site assembly.[16] The definition of an SMR does not formally stipulate the design or fuel type of the reactor; light water, gas-cooled, and liquid metal system types may all appear in different SMR designs.[17] Most SMRs share a common set of basic design characteristics that distinguish them from traditional, large-scale nuclear reactors.

SMRs, which are smaller and cheaper than conventional nuclear power plants and, as compared to certain other baseload power alternatives, may present an opportunity to reduce emissions from baseload power generation in the future, offer a more secure power source, and provide more reliable power.

### 1.3 Benefits Offered by Small Modular Reactors

SMRs bring certain benefits which could justify using them over other, less costly sources of baseload power in some cases. As identified above, much coal generation capacity is expected to be retired in the foreseeable future.

As compared to other power sources, SMRs may offer the following benefits, each of which are explained in more detail in Appendix A:

- Carbon-free baseload power
- Enhanced safety
- Modularity
- Lower cost
- Scalability
- Improved energy security
- Integration of renewables
- Siting flexibility
- Small land requirements
- Process heat
- International export opportunities
- Reduced fuel risk

The potential benefits of SMRs should be weighed against the cost of power from SMRs when making generation investments. These benefits may not justify the use of SMRs in all places for all off-takers, but SMRs may nonetheless be attractive where modular or small baseload power plants are warranted, when there is a need to diversify the baseload generation portfolio, when there is a need for highly reliable power, or where reducing carbon emissions from baseload generation is a key priority.

### 1.4 Challenges for Baseload Power Investments

The high investment cost and long project lives of baseload power plants present financing challenges for utilities trying to align investment in additional generation with customers' demand for power. Adding to these challenges is the uncertainty introduced by wholesale and retail competition over the past 20 years. Despite the uncertainties, large-scale baseload power plants will need to be developed, designed, and constructed to replace an aging fleet consisting largely of coal and nuclear generation. Given the high investment cost, power plants will rely on long-term debt financing for economic feasibility. Current baseload power plants are coal, large-scale nuclear power, natural gas, and hydro facilities. In each region of the country, utility owners are replacing these baseload facilities with new facilities and are reviewing the options of new baseload facilities (such as SMRs) and comparing the prices with building new coal, natural gas, or large scale nuclear power facilities or upgrading existing facilities.

Debt and equity investors in energy projects have a number of issues and concerns that must be addressed before becoming sufficiently comfortable to extend financing for these projects. The availability and amount of funding from each source will reflect the risk profile of the project. Developers and off-takers will seek to maximize the amount of low-cost debt in the capital structure in order to make the project cost-competitive. However, lenders have a limited appetite for risk, so projects with high-risk profiles may require greater amounts of equity, placing upward pressure on rates.

## 1.5 Challenges to Commercial Deployment of Small Modular Reactors

SMRs face certain challenges in reaching commercial deployment common to nuclear power plants and additional specific challenges resulting from the technology being new. These challenges include:

- **Regulatory Uncertainty:** All nuclear plants are regulated by the NRC, in addition to state electricity regulators and other agencies. In 2011, a survey conducted by Scully Capital for DOE identified that industry professionals were worried that standards for SMRs may largely replicate those for larger, conventional nuclear plants.[18] This may pose particular challenges with respect to staffing requirements and sizes of evacuation zones and could increase costs. Also, the timing and process for SMR permitting is not known, which increases uncertainty and potential costs of developing a project.

- **Waste Disposal:** As with conventional nuclear reactors, it is necessary to safely dispose of waste from SMRs. Spent fuel is radioactive, and, thus, must be stored safely in order to avoid harming people or the environment. Most spent fuel in the United States is stored in specially designed pools at reactor sites. No long-term, permanent site for storing spent fuel from commercial power plants has been built.[19]

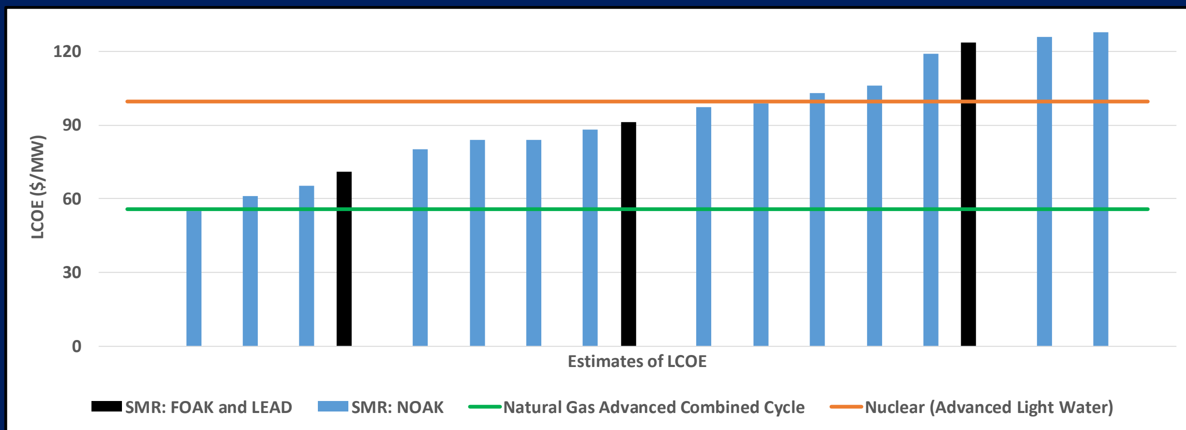
- **Cost:** Electricity from SMRs may not be cost-competitive with most dispatchable generation options, although the price of power from SMRs is expected to fall as manufacturing processes are improved. For example, one study estimated that the cost of power from SMRs with economies of scale (Nth of a Kind or "NOAK") is 50 percent less than for the first batch of SMRs with a design that approaches scalability (FOAK).[20]

- **Financing:** SMRs will face challenges in raising financing to fund construction. The energy markets are in a period of rapid transformation, competing sources of baseload power, namely gas-fired power plants, are highly competitive, and SMR cost and performance has yet to be demonstrated commercially. At a minimum, these considerations increase the cost of financing, undermining the cost competitiveness of SMRs.

Figure 4 shows that Levelized Cost of Electricity ("LCOE") from SMRs (vertical bars) has generally been estimated to be higher than LCOE for baseload power from natural gas (the lower horizontal line).[21, 22] However, NOAK SMRs are generally estimated to be cheaper than conventional nuclear reactors (the highest horizontal line).[23]

**Figure 4**

**Levelized Cost of Electricity for Baseload Power[24, 25, 26, 27, 28]**




Regulatory uncertainty, waste disposal, and cost present challenges to the commercial uptake of SMRs. However, these challenges should be weighed against the advantages of SMRs in replacement of retired baseload power plants in coming years. Future use of SMRs may be encouraged by federal government initiatives to overcome challenges facing SMRs, thus helping realize their full potential for the power sector.

## 1.6 Federal Government Actions to Encourage the Development of Small Modular Reactors

The federal government is supporting the development of SMRs in a number of ways. For instance, DOE has a cooperative agreement with NuScale under which NuScale will receive up to $217M in matching funds over a five-year period to support the accelerated development of its NuScale Power Module™ SMR technology.[29] In addition, in December 2014, DOE's Title XVII loan program issued a solicitation for loan applications to finance advanced nuclear energy projects SMRs.[30] There is also discussion related to legislation extending the expiration date of PTCs for nuclear energy which, if passed, would measurably improve the economics of an SMR.[31]

Leveraging the federal government's strong credit standing and its continual need for baseload power represents another feasible tool that could advance the development of SMRs. Federal agency purchasers can help to set the market and offer more certainty to other initial buyers. Additionally, when making purchases, federal agencies evaluate the best value for the government. Policy considerations will come into play in such a decision, as value does not automatically equate to the lowest cost. For example, a federal user may place a premium on the reliability and energy security offered by an SMR, even though this power source may be priced higher than other available power sources. By electing to use an SMR even though it may not be the lowest priced power source, the federal government may help to increase the marketplace for SMRs and drive down costs for other future potential users.

# CHAPTER 2:
# POWER SUPPLY OPTIONS FOR FEDERAL CUSTOMERS

**KEY POINTS FOR CONSIDERATION**

- The federal government consumes a significant amount of electric power and spends large sums of money on power as part of its day-to-day operations.
- The United States power sector is complex and has a diverse range of power purchase options which are commonly used by large consumers of power. Different options may be better suited to different financial or policy goals.
- Federal law limits the flexibility of federal agencies in purchasing electric power, as compared to the typical range of options available to private entities.

The United States power sector has evolved significantly from its origins in small, private monopoly utilities under municipal regulation to a mix of public and private providers operating in different market structures under different forms of state and federal regulation. In its current form, the United States power sector is a collection of state and regional markets. These markets vary by the regulatory regimes imposed by the states and the extent to which they are competitive. The market and regulatory arrangements impact many issues, such as who can develop projects, who can buy and sell power, how power is priced, and how power is sold. These issues all influence how power projects can be developed and financed.

The variety of ownership arrangements, market structures, and regulations leads to a variety of commercial arrangements for developing and purchasing baseload power in different areas. This Chapter examines the potential offered by federal PPAs and introduces the current contractual mechanisms under which power is purchased in the commercial sector.

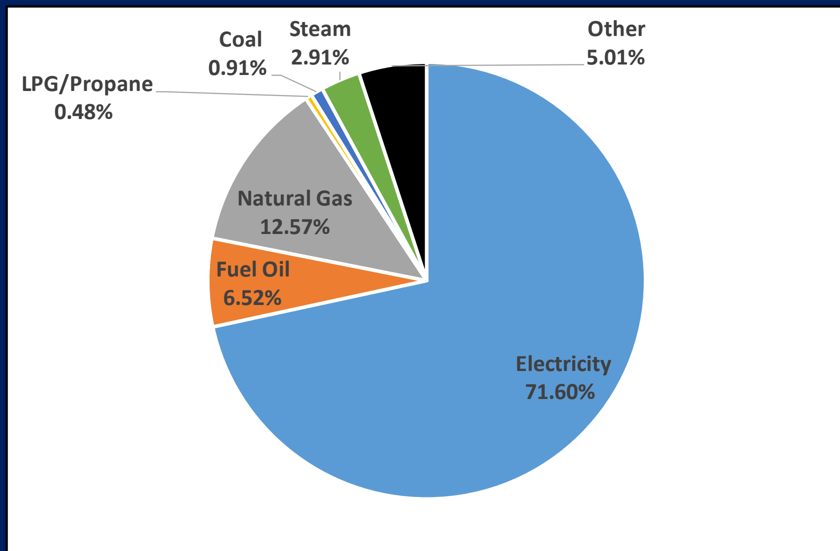
## 2.1 Overview of Federal Power Consumption

The federal government is the largest consumer of energy in the United States.[32] In FY 2015, the federal government spent $21.3 billion on energy to consume 947.0 billion British thermal units ("Btus") of energy.[33, 34] 62% of energy use (584.9 billion Btus) and 69% of spending on energy ($14.6 billion) went to fuel for vehicles and equipment.[35] The remaining 38% of the government's energy use (373,5 trillion Btus) and 28% of its spending ($6.7 billion) was consumed by buildings and other facilities.[36]

Electricity comprised half of energy consumed by buildings and facilities in terms of Btus. The proportional spending on all energy sources for buildings and facilities is shown in Figure 5.

## Figure 5

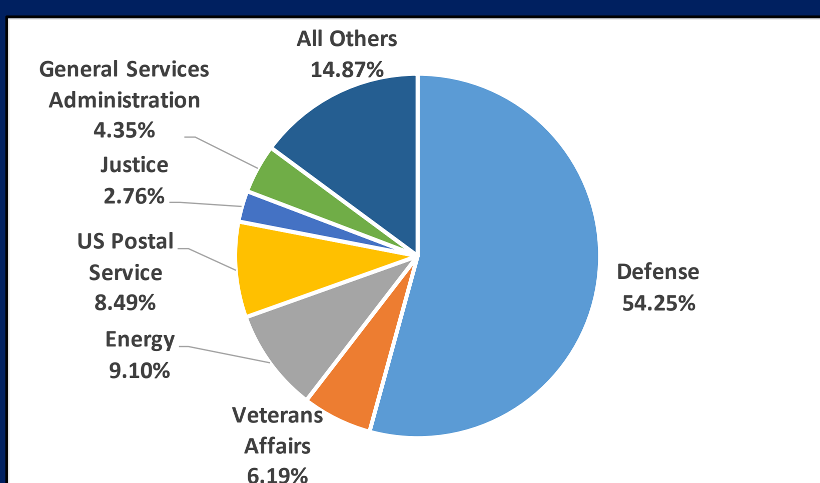
**Energy Use by Federal Buildings and Facilities in FY 2015**[37]




Electricity represents an even larger share of energy spending for buildings and facilities, comprising 72% ($4.8 billion).[38] The largest user of electricity for buildings and facilities is DOD, comprising 54% of electricity use and 54% of spending on electricity.[39] The second-largest user is DOE, comprising 9.1% of electricity use.[40] However, DOE was the fourth-largest spender, comprising 5.9% of spending (the United States Postal Service and the Department of Veteran Affairs came in second and third).[41] Energy consumption by government agencies is shown in Figure 6.

## Figure 6

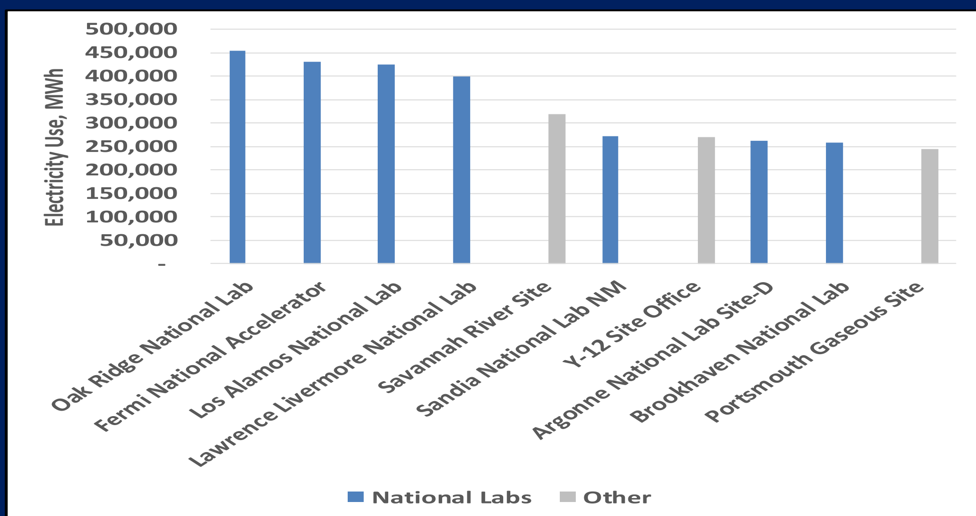
**Electricity Use by Federal Agency in FY 2015**[42]



DOE has 56 sites that report electricity consumption.[43] The 10 largest sites by energy consumption comprise 69% of the agency's total consumption.[44] Seven of the top 10 are national laboratories, including the top four. Oak Ridge National Laboratory consumed the most electricity at DOE, followed by Fermi National Accelerator, Los Alamos National Laboratory, and then Lawrence Livermore National Laboratory.[45] Annual electricity consumption at the 10 largest DOE sites is shown below in Figure 7.

**Figure 7**

**Electricity Consumption at 10 Largest DOE Sites in FY 2015**




Given national laboratories' large power consumption and mission to support innovation in energy technology, they may be attractive off-takers for an SMR. The type of offtake arrangements that laboratories or other sites can employ depend on the legal authorities that the potential off-takers can use for procuring power, the location of the SMR, and the cost implications of entering into a long-term PPA.

## 2.2 Market Context: United States Power Sector

Since the late 1800s, the United States power sector has evolved from urban businesses under municipal regulation to a nationwide industry with public and private service providers operating under federal and state regulation. Federal regulatory reform, starting in the late 1970s, drove increased competition which diversified the ways that power generation could be purchased and financed. Today, some states' power sectors largely consist of vertically integrated utilities which provide all wholesale services (production and long-distance transport of power) and retail services (delivery of power to end users) in a state-regulated monopoly, while others permit competition in certain parts of the sector.

Baseload generation projects have long lives and high investment costs, which can present challenges in arranging adequate financing. Power markets and regulation vary significantly across the states. When planning to buy from or finance a generation project, the local market and regulatory conditions need to be understood. These conditions can significantly impact the economic feasibility of a generation project. In particular, the location of an SMR and where its power is being delivered will be key determinants of the market and regulatory factors that impact a project's financing.

Please see Appendix B for further discussion on the following topics:

1. Main segments of the United States power sector and their ownership;
2. Power sector ownership models;
3. Regulation of the power sector;
4. Wholesale power today; and
5. Retail competition.

## 2.3 Common Options for Large Consumers to Buy Power

The introduction of competitive markets in some states has increased consumers' options for buying power. While traditional utility contracts are still common, many consumers now have options to buy energy directly from generators or generate it themselves. The following Sections describe five power purchase options for large consumers of electricity, such as municipal and private utilities, large industrial facilities, or large federal facilities.

### 2.2.1 Utility Contracts

The most common power purchase option for consumers is a utility contract. Utility services may come in the form of all-requirements contracts. Under these contracts, the utility agrees to meet all demand from the buyer, and the buyer agrees to only take power from the utility. As such, the utility will reserve adequate capacity to meet the customer's load requirements. Consumers typically make regular payments that vary based on the amount of power used. Utilities aim to get permission from regulators to set rates that allow for recovery of all costs. Pricing schemes for electricity services vary significantly across different utilities and users. Large users of electricity may be able to enter into favorable pricing arrangements with local utilities. Many utilities also offer demand management services to help consumers lower their energy costs.

### 2.2.2 Self-Generation

Some large consumers of power may choose to generate their own electricity, if permitted by applicable regulations. This will generally make sense if producing power on-site is cheaper or more reliable than the likely alternative. A consumer that generates its own power, but also buys from the grid, may be required to pay standby charges. These charges are effectively ways for a utility to recover the cost of maintaining capacity and the grid even when no power is sold.

Small self-generation projects are called distributed generation ("DG"). Projects up to 10 megawatts ("MW") in size are typically classified as DG. Much DG in the United States is from solar panels. In some markets, local regulation may permit consumers using DG to sell power into the grid if they produce more power than they need to use. This is called net metering, because a customer's meter can measure whether the customer ends up buying from or selling to the grid.

Net metering can reduce utility bills, because the utility pays the customer for power sold into the grid. Some federal agencies (especially military bases) use DG for solar, co-generation facilities, and other similar projects on large federal facilities.[46]

### 2.2.3 Power Purchase Agreements

A PPA is a long-term contract to sell electricity between a producer of electricity and a buyer. PPAs are typically project-specific, in that a buyer agrees to purchase power from one power plant. Buyers of power in PPAs are typically referred to as "off-takers" and could be utilities or end-users in jurisdictions where the retail sale of power has been deregulated.

Project-specific PPAs are key to enabling developers or independent power producers ("IPPs") to finance power projects through project financing. In project financing, a financier (lender or equity investor) provides capital based on the financial strength of a given project and, in particular, the internally-generated cash flows that the project is expected to produce. This contrasts with corporate financing in which financing is provided based on the financial strength of a whole company, which may have many projects and activities, and provides financers with recourse to the borrower's balance sheet.

The PPA provides revenue to the project company during the term of the PPA. This revenue enables the project company to pay for goods and services according to terms of supply contracts and make payments to lenders and equity investors according to their respective agreements. The capital from lenders and equity is used to pay the engineering, procurement, and construction ("EPC") contractor to build the project. Lenders and equity investors agree to finance projects because they expect their initial capital to be repaid, plus an additional return (interest for lenders, dividends for equity).

Depending upon a project's size, developers or IPPs may seek to enter into one or multiple PPAs in advance of securing financing. If lenders and equity investors lack confidence in the likelihood of being paid under a proposed PPA or if additional PPAs have not been negotiated at the time of financing or for the duration of the financing, they will not agree to finance the related project. Thus, a key determinant of whether financing will be made available to build a project is the availability, scope, and term of PPAs that are negotiated at the time financing is considered.

### 2.2.4 Virtual PPA

A "virtual PPA" is a long-term contract between an off-taker and a producer of power in which power is not physically delivered to the off-taker. That being said, as in a standard PPA, a virtual PPA results in a producer being paid for producing power and the off-taker receiving power. Virtual PPAs also can include a hedging arrangement to provide protection against variations in the market price of power. Virtual PPAs are also known as "synthetic PPAs."

Given the complexity of virtual PPAs, they may be best suited to large consumers of power that are able to bear significant transaction costs in preparing virtual PPAs. Virtual PPAs are sometimes used for renewable energy under a different arrangement that includes the sale of Renewable Energy Certificates ("RECs") and the use of hedging instruments to protect against variation in market prices. At present, power from SMRs does not qualify for RECs.

### 2.2.5 Contracted Capacity

Contracted capacity is an arrangement where a group of off-takers (typically utilities) divides up a project's power production. In these arrangements, multiple off-takers jointly own and finance a project either directly or through a membership association. Each off-taker is entitled to a "slice" or "undivided interest" of the project's output and has to pay for a share of the project's costs. The parties subscribe to specific capacity amounts, and payments represent a take-or-pay arrangement commitment of the subscriber. Therefore, plant performance or the off-taker's actual usage do not affect the payment obligation. Contracted capacity is illustrated in Section 6.2, as it is currently the method that UAMPS is utilizing to finance the Idaho SMR Project. Further, many large utility plants, including recent nuclear power plants, have been financed using this structure.

## 2.4 Challenges for Federal Customers

Despite a compelling demand profile, federal customers face a myriad of challenges when seeking to enter into long-term agreements for the purchase of power. Federal purchases of power must consider the dynamic nature of today's energy market (including base power demands and price fluctuations), while also addressing unique legal, economic, and budgetary accounting considerations. In examining the feasibility of using federal PPAs to support the commercialization of SMRs, all of these factors must be considered and addressed. In many circumstances, the 10-year limitation placed on federal PPAs presents a significant challenge when financing for SMRs will likely require a term of 30 years or more. These topics are explored in the Chapters that follow.

**KEY CHAPTER TAKEAWAYS**

- PPAs are a potentially useful tool for a federal agency to use to purchase power from a specific power plant, and, thus, support specific technologies by purchasing power from plants which use those technologies.

- Since DOE already is purchasing significant amounts of power, purchasing power from a specified technology could be an attractive way for DOE to support technology development through a routine activity.

- Careful consideration will have to be given to developing a PPA for a federal off-taker to buy power from an SMR. Except in certain limited circumstances, federal law typically limits federal off-takers' PPAs to a maximum term of 10 years, while SMRs will typically have financing with a term of more than 30 years.

# CHAPTER 3: FINANCING CONSIDERATIONS FOR ENERGY PROJECTS

**KEY POINTS FOR CONSIDERATION**

- Generation projects can be financed in many ways. The choice of financing arrangement is often heavily influenced by whether the project will be part of an integrated corporation, held in a standalone project company, or owned by a public power utility.

- Introducing federal customers into a project requiring financing can be an asset by helping the developer demonstrate the need and market for the project. However, federal customers also have unique limitations that make financing challenging.

This Chapter describes the typical financing scenarios and common concerns of investors and lenders in financing energy projects generally and additional specific concerns with respect to financing federal power purchases of baseload power. This Chapter provides the basis for the legal authorities and the considerations federal agencies need to evaluate when purchasing power from an SMR, which are described in Chapter 4 and Chapter 5 respectively. In addition, Chapter 6 applies these principles to the Idaho SMR Project.

## 3.1 Typical Financing of Power Projects

The approaches to financing power projects will vary based on the needs of the project sponsor, the risks presented by the project, and the availability of capital. Energy projects can involve complex ownership structures and multiple creditors with secured interests, but the financing approaches can be summarized generally into three financing models. In all likelihood, the SMR financing approach will fall into one of the following three categories:

1. Non-recourse or limited-recourse project financing;
2. Corporate/balance sheet borrowing; and
3. Public power financing.

### 3.1.1 Non-Recourse or Limited Recourse Project Financing

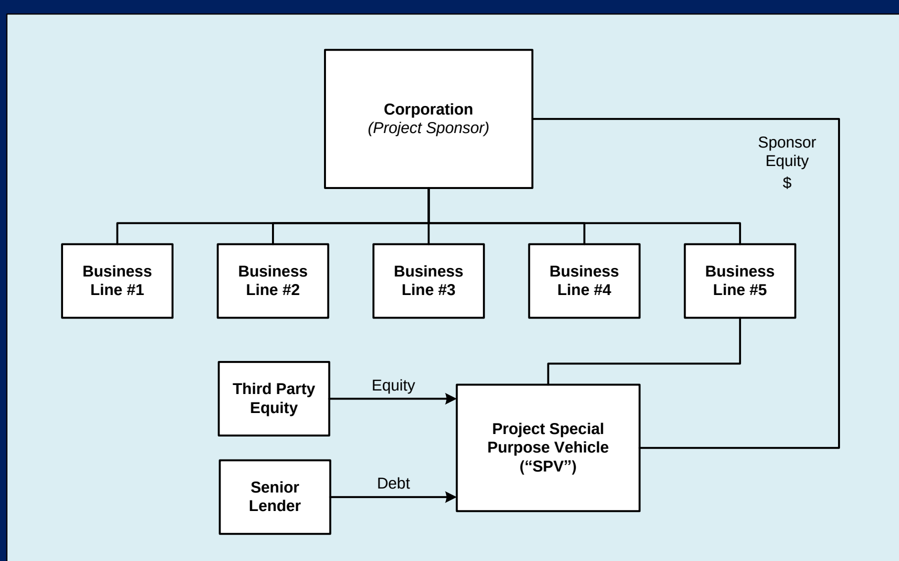
In a non-recourse project financing, lenders look to the performance of the project for payment rather than the project sponsor's balance sheet. This enables the project sponsor to isolate the risks presented by the project, making the loan non-recourse to the borrower. A project financing typically includes a group of agreements and contracts among senior lenders, the project sponsor, and other interested parties, and the formation of a special purpose vehicle ("SPV").

In a typical project finance scenario, the project sponsor sets up a separate company – a SPV. SPVs usually take the form of a limited liability company, which is created for the purpose of allowing the sponsor company to pledge equity to the debt lenders. SPVs typically will issue a finite amount of debt on inception, operate as a single line of business, and ask that lenders look only to specific assets to generate cash flow as the sole source of principal and interest payments and to serve as collateral. The new company allows for most liability and risk to be contained in the new company, thereby insulating the project sponsor from liability in the event of default or other claims. There will also be agreements for the development, construction, ownership and operation of the project, as well as administrative service agreements and technology licensing agreements. This involves multiple parties with varying interests to protect. By design, all repayment of debt under a project financing is derived from the project's operations; the project debt repayment terms do not provide for recourse to the project sponsor's balance sheet.

Once the sponsor places its equity at risk into the overall financing of the project, it will then be leveraged with the debt financing provided by the lender. The more comfortable lenders are with the overall project, the more leverage will be permitted. As depicted below in Figure 8, the SPV is capitalized by equity contributed by its owners or third parties and senior debt secured by the project.

**Figure 8**

**Project Financing**




A limited recourse project financing closely resembles a non-recourse project financing. The principal difference is that a limited recourse project financing has additional financial support during the completion and pre-operational phases of the project (pledged by an affiliate or the project sponsor), which is subject to certain limitations and caps (e.g., completion guarantees, contingent equity commitments).

Over the last several decades dating back to the 1970s, non-recourse project financing has been used extensively to finance energy projects. Although these are complicated transactions with many parties involved and multiple business and legal considerations to address and resolve, there are ample examples of successful project finance transactions. Also, if there are federal or state funds available through grants, loans, or tax incentives, there may be additional complexities to closing the transaction. As such, the project must be of sufficient size to support the necessary upfront work needed to bring the transactions to closure.

To attract lenders to finance power projects, lenders will want to be assured that there is a steady revenue stream that will not be interrupted and that there is a high likelihood that they will be repaid entirely for all principal and interest over the life of the loan. Key elements lenders consider are:

1. **Technology Stability.** Is the technology being financed sufficiently stable so as to be deemed commercially viable? Lenders are unlikely to be the first to finance an untested technology.

2. **Performance Assurance.** Lenders will want to lend to projects that are likely to perform as expected, including completion and operations, and thus generate power for sale as expected. Lenders will often review technical plans and require performance bonds or other assurance instruments to cover certain events in which projects do not proceed as planned. Engineering, design, and procurement contractors typically post some sort of security to provide compensation in the event of construction delays or budget overruns.

3. **Marketplace.** Is there a marketplace for the energy that is produced by the technology so that there is a predictable revenue stream? Typically, this is accomplished through the use of a PPA with the local utility, merchant agreements with private parties who agree to purchase power directly, and other techniques to provide assurance that the debt will be repaid.

4. **Contract Term.** Lenders prefer long-term contracts that last over the period of the repayment of debt. In the absence of a long-term contract, lenders can become comfortable with "merchant risk" under specific circumstances or if there are sufficient assurances through guarantees, warranties, and other contractual commitments to make the project financeable.

5. **Availability of Human Talent and Special Technology.** Lenders will consider whether the human talent and special technology is protected by agreements and not likely to disappear during project performance.

6. **Events of Default.** Lenders ensure they are protected upfront in the event of a default during the construction or operation of the project. Lenders will evaluate in advance whether there are sufficient physical assets or "recovery value" to ensure that there will be repayment in the case of foreclosure either by selling the project outright or operating it until the debt is repaid.

7. **Upfront Consents.** Lenders will want to obtain upfront consents to collateral assignments from some, if not all, of the participating parties to assure their cooperation if an event of a default occurs.

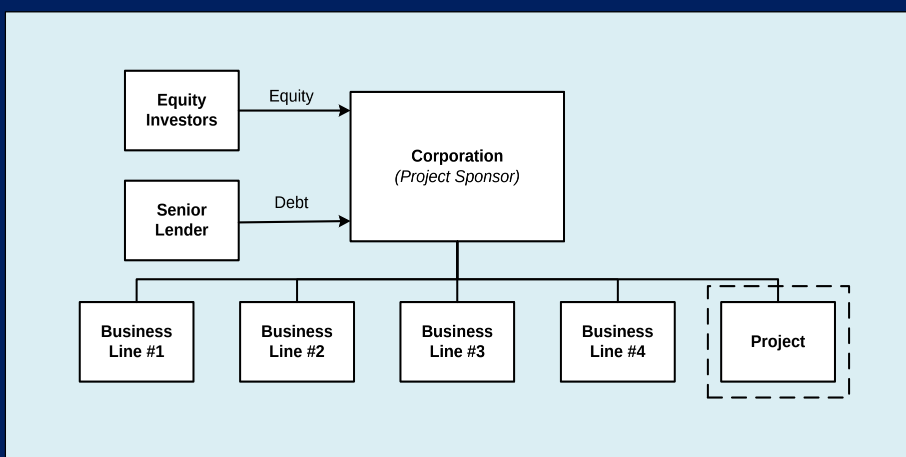
8. **Closing Assurances.** At closing, lenders will want assurances that the technology is commercially viable, the marketplace will sustain the payments necessary to repay the loan, there are no environmental concerns or investigations needed, insurance is available to protect the lender's interests, land surveys and site descriptions are in place, the equity from the sponsor or other parties has been contributed, and all necessary third-party and government approvals and permits are in place.

### 3.1.2 Corporate / Balance Sheet Borrowing

Under a traditional corporate financing, the parent corporation supplies equity to the project and borrows debt from a bank or the bond market to fund a variety of corporate needs and projects. The debt and equity investors benefit from a pledge by the corporation to repay principal and interest. In some cases, corporate borrowings will be secured by specific project assets, while in others, corporate borrowings will be unsecured. In the latter case, bondholders are comfortable with the long-term viability of the business and are willing to lend on an unsecured basis provided assets are not pledged to other creditors. As depicted below in Figure 9, lenders look to the business enterprise for repayment. While the project performance represents a consideration, its success or failure is one of many considerations.

**Figure 9**

**Corporate Financing**




While the balance sheet/corporate borrowing method may be beneficial in that it includes the revenue stream and profitability of other lines of business as a source of debt repayment, it also subjects the project to the financial vulnerabilities of the corporation's other activities.

To attract long-term, low-cost debt capital, utilities financing assets under a corporate borrowing will have to demonstrate strength in a number of areas. Key credit factors considered by lenders include:

1. **Management.** The management track record includes the ability to achieve strategic goals, engage in effective resource planning, and manage and mitigate risks. Importantly, evaluation of management will also include consideration how quickly costs – especially investment costs – can be recovered through rates. Some management teams have been observed over time to be better at receiving permission from regulators for rate increases. In some cases, cost recovery through regulatory processes is transparent, predictable, and consistent, allowing for the issuance of long-term, low-cost mortgage bonds. On the other end of the spectrum, a utility who faces uncertainty in receiving permission for desired rate increases is at a significant disadvantage for raising capital. The regulatory risk associated with long-term cost recovery is highly uncertain in these cases, potentially leading to volatile cash flow performance and stranded assets which cannot recover their costs.

2. **Utility Operations.** This includes an examination of a utility's operating efficiency, reliability, power and fuel resource mix, environmental compliance, and capital needs over time. To inform this analysis, rating agencies often benchmark a utility against its peers for standards of fuel mix, capacity factors, ratio of staff to power output, unplanned outages, line losses, plant heat rates, and other factors. The analysis is targeted at any insight to the day-to-day operational performance of the utility relative to industry standards. Large investment in a new technology that has not been widely used would probably increase uncertainty about future operational performance.

3. **Competitive Position.** In examining the competitive position of a utility, retail rates will be compared to state averages and to neighboring systems. This will include analyzing the utility's cost structure, rate setting flexibility, and rate affordability. The utility's willingness to recover costs through rate increases, as well as its ability to obtain the necessary regulatory approvals, are important inputs for assessing the utility's competitive position. Additionally, the ability of the utility to maintain its position as an essential service and support its monopoly status are important.

4. **Service Territory.** The socioeconomic condition of a utility's service territory provides insight into the affordability of electric rates and the territory's ability to absorb rate increases in the future. Important socioeconomic indicators include demographics, unemployment rates, population growth rates, customer diversity, and overall economic stability of the customer base. Local economic diversity and customer concentration are also important.

5. **Financial Position.** The financial position of the utility provides quantitative measures for assessing the current financial health of the utility, as well as its long-term financial prospects. The key metrics in this analysis include debt service coverage ratios, equity ratios, capital structure, debt profile, and future financing needs. Structure of the existing and outstanding debt including lien position, revenue pledges, rate covenants, and other structural supports will influence the assessment of the financial strength. Equally important is the utility's capital expenditure program and the impact on operational

performance of capital improvements or deferrals of such improvements. The financial performance metrics are often a key input for credit rating agencies.

While the above criteria are all applicable to all power producers, the importance of each criterion will be influenced by the type of utility that is borrowing, the kind of regulation to which the utility is subject, and the financial structure of each baseload generation project.

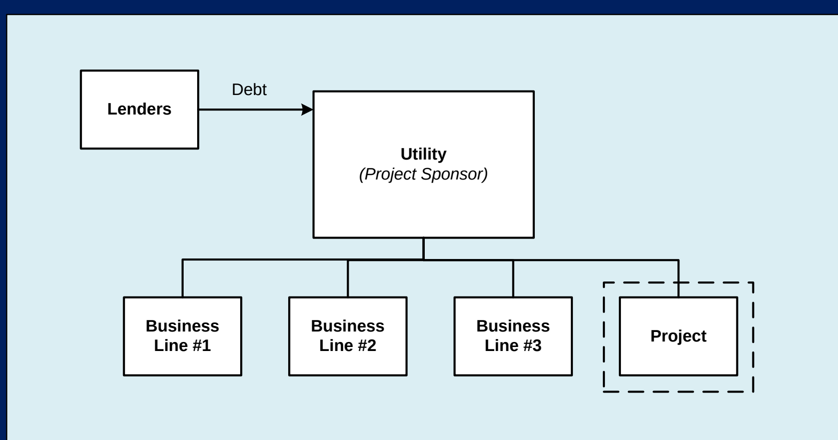
### 3.1.3 Public Power Financing

Public power utilities commonly own power generation and finance this generation through debt. Public power utilities may own and finance generation projects individually or collectively own and finance projects through joint action agencies. When owning and financing a project individually, public power utilities generally borrow against the financial strength of the utility as whole, which should reduce risks to lenders, and, thus, borrowing costs relative to borrowing on a project basis. Thus, a public utility may finance a single generation project through revenues or collateral from across the whole utility, rather than just from the single project. See Chapter 6 for the Idaho SMR Project example that uses this structure.

A typical public utility financing structure is illustrated below in Figure 10, where one utility owns a project.

**Figure 10**

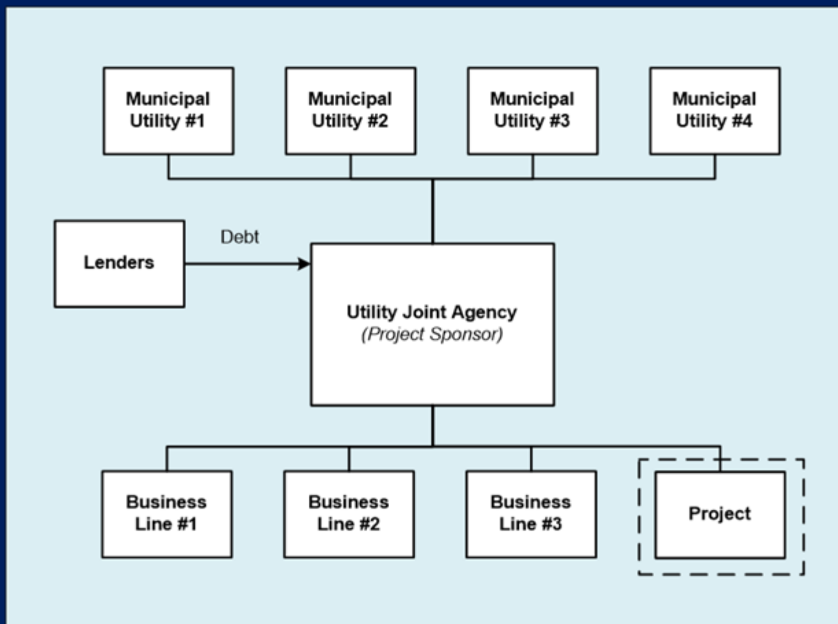
**Public Utility Financing with Single Owner**




Some public power utilities may own and finance generation collectively. Joining together to develop a generation project through a joint action agency allows public power utilities to reduce costs and risks by pooling their financial strength. In a joint arrangement, several public power utilities create a joint agency, through which they have joint participation interests and financial obligations in generation projects. Each project may act as an independent utility for borrowing purposes. This is often done through take-or-pay arrangements, whereby the utilities which jointly participate in a project all remain responsible to pay all project costs (including debt service) even if no power is delivered. This is attractive for lenders, as it helps ensure that funds will be available to repay debt and spreads repayment risk across multiple utilities. A typical joint ownership and financing arrangement is shown in Figure 11.

**Figure 11**

**Public Utility Financing with Joint Ownership**




To be interested in providing financing for a public power project, lenders will have to be assured that there is a steady revenue stream that will not be interrupted and that there is a high likelihood that they will be repaid in full for all principal and interest over the life of the loan. Lenders considering a loan to a joint action agency power project will have the same general considerations as if they were considering a loan to a single utility; however, in the case of a joint action agency project, lenders will analyze multiple public power utilities' likelihood of repaying their respective shares of the debt. Spreading the repayment obligation across multiple utilities can result in lower borrowing costs, all else being equal.

Key elements which lenders consider in financing a public utility, whether as a standalone borrower or as part of a joint financing, are:

1. **Service Territory.** A public utility's service territory is the market into which it sells power. The service territory's ability to absorb rate increases is thus a key determinant of a utility's ability to charge rates that allow for repayment of financing and recovery of other costs. In assessing a utility's service territory, lenders will analyze the strength of a utility's monopoly position; in many territories, a public utility may be the sole service provider. However, some state regulators allow for competition in retail supply of electricity, as discussed in Appendix B. A utility's ability to raise rates also depends on the regulatory regime under which it operates. Most public power utilities, with some exceptions, are not regulated by state regulators, and thus have significant autonomy in rate setting. Lastly,

service areas that are economically diverse and wealthier generally have commercial and residential customers which are better able to absorb rate increases.

2. **Willingness and Ability to Recover Costs.** Public power utilities generally set their rates without regulatory oversight, but they may not always exercise full rate-setting flexibility in practice. This may result from public policy concerns that prioritize the interests of customers over the utility's financial policy. A public utility's ability to raise rates is often a function of its relationship with the government which owns it. Lenders will examine a public utility's timeliness in rate setting to see if it has a history of raising rates relatively quickly to match cost increases. Other factors that are examined are the transparency of a utility's relationship with the owning government and the government's provision of financial support to the utility (such as transfers to a utility from a city's general fund).

3. **Generation and Power Procurement Risk.** Public power utilities which own a significant amount of generation, whether directly or jointly with other utilities, face risks related to the economics of power generation. Lenders will examine the diversity of a utility's generation sources to analyze what generation risks are significant. A utility that relies heavily on one type of fuel (such as coal) will face significant exposure to the price of that fuel. Lenders will also examine technical reliability of generation to assess how often generation facilities are likely to be operational, thus generating revenue. Lenders may also examine utilities' flexibility in switching between fuel sources, which may be a function of transportation constraints (such as pipeline capacity for natural gas), regulatory considerations, and hydrological risk in the case of hydropower.

4. **Rate Competitiveness.** Public power utilities typically do not compete with other service providers, but price competitiveness does impact utilities' ability to raise rates. Lenders typically compare a public utility's average system rates against other utilities (ideally against neighboring utilities in the same state to compare utilities in relatively similar environments). If a utility's prices are relatively high relative to peers, then it may be harder for the utility to raise rates in the future. Generally, utilities that have lower rates relative to peers will have more flexibility in raising rates in the future.

5. **Financial Strength and Liquidity.** A public utility's financial position is an important factor in assessing its ability to repay debt. Lenders will focus on analyzing a utility's current and projected access to cash and how that compares with the utility's debt repayment obligations. This will include analyzing the utility's revenue and its access to credit lines. Lenders can use a range of financial metrics to assess financial strength, such as the Debt Service Coverage Ratio, which divides the expected cash flow available to pay for debt service by the total amount of debt service obligations in a time period.

Other considerations are also meaningful in deciding to lend to public power utilities. In addition to the considerations discussed in Section 3.1.1 and Section 3.1.2, these include operational considerations, such as construction risks faced by a utility and the extent to which a utility is a vital service provider in its service territory (for example, if a utility is the primary provider of transmission services in a large economic region). Lenders may also examine a utility's existing and projected debt structure to assess exposure to interest rates or other financial risks and the extent to which a utility may benefit from guarantees or other preferential support from the government which owns it.

Lenders may also examine the stability and diversity of a utility's revenue. Public power utilities' revenues are generally stable as power is sold through long-term contracts with customers, but some utilities also sell power into wholesale markets with market-based pricing. Smaller utilities may receive a large part of their revenue from a few customers, which increases concentration risks. Utilities which sell other services (such as water supply) may have revenue streams which offset volatility in electricity revenue.

In summary, public power utilities have to ensure potential lenders that they are willing and able to charge rates that will allow for debt repayment, and that other risks are not major impediments to debt repayment. In making a lending decision, lenders will focus on how a utility's ability to raise rates in the future, the utility's financial strength, and how other risks, such as operational and revenue risks, may impact the utility. When lenders consider a loan to a joint action agency project, they will assess the financial strength of at least the larger participating utilities individually, if not all the participating utilities.

### 3.2 Additional Financing Considerations for Projects with Federal Off-Take

As discussed above, lenders conduct extensive due diligence when deciding whether to finance traditional power projects. The emphasis of such diligence will reflect the credit structure involved. The introduction of a federal customer via a PPA raises additional diligence issues and lender considerations which do not fit neatly with commercial financing standards. These issues have been confronted by developers and lenders in third-party financings of energy infrastructure on federal lands and include:

1. **FAR-Based Contracts:** Federal contracts are typically drafted pursuant to the Federal Acquisition Regulation ("FAR"). As such, terms and conditions are subject to a set of precedents which is unfamiliar to many project finance lenders. Additionally, under a FAR-based contract, significant discretion resides with the Contracting Officer. This is contrary to the commercial approach to drafting project finance documents which attempt to predefine remedies for a variety of conditions or circumstances.

2. **Contract Term:** In most circumstances, federal agencies are limited to entering into a PPA with a maximum term of 10 years; however, most traditional financing will be repaid over a 30-40 year term. Depending upon the size of the federal agency's off-take, as compared to the size of the power source being funded, this discrepancy may make it difficult for financing. For example, if a federal customer's needs represent 75% of the project, it will be risky for an investor to provide financing that is repaid over a term greater than the PPA. Alternatively, if a federal customer's needs represent 5% of the project, the lender may be unconcerned with a 10 year PPA from the federal agency and expect that other users can cover that demand in the event that the PPA is not renewed during the debt repayment period.

3. **Lender Step-In Rights:** In the event the project borrower fails to meet its financial payments or agreements, lenders will want to have the right to step-in and take over operations to assure the continuity in the flow of revenue. This may require a special contract clause under the FAR and is often the subject of considerable discussion/negotiation.

4. **Lease Agreement:** All parties to the transaction must be satisfied that there is appropriate legal authority for siting the project – whether it be on federal land or elsewhere. This may require the payment of rent equivalent to the fair market value and often requires considerable discussion over the allocation of risks related to the site environmental condition, particularly if the project is located on federal land.

5. **Termination for Convenience:** By law, all FAR-based contracts must provide for the government's right to terminate for its convenience. This language includes provisions related to compensating the developer, but introduces uncertainty into the project, a condition lenders seek to avoid. A termination for convenience event may or may not compensate the developer for all of its costs.

6. **Cybersecurity:** Cybersecurity has become an issue for projects installed "behind the meter" and integrated with the federal off-taker's supervisory control and data acquisition systems. Generally, requirements related to cybersecurity place requirements on PPA counterparties that are difficult to quantify and will change over time.

7. **Procurement:** Federal agencies must comply with specific procurement policies, which may require competitive selection depending upon the circumstances.

8. **Unique Approval and Negotiation Processes:** In certain circumstances, additional and sometimes time-consuming approvals are required for a federal agency to enter into certain PPAs, such as approvals by the Office of the Secretary of Defense for certain DOD authorities or Congressional notifications. Additionally, in certain circumstances, separate federal agencies may be conducting the negotiations on behalf of the federal agency that will be consuming the power, such as GSA acting on behalf of an office for the U.S. Department of Housing and Urban Development or the Defense Logistics Agency acting on behalf of a DOD department.

### KEY CHAPTER TAKEAWAYS

- Generation projects with PPAs lend themselves to project financing. In these situations, debt is secured by revenue and collateral from a single power plant. PPAs can reassure lenders by providing the project with a reliable revenue stream which should enable the project to repay debt.

- Federal off-takers can enter into PPAs to purchase power that is financed as an individual project. The terms of federal PPAs may differ from common commercial PPAs due to requirements of federal law. Typical PPAs with federal off-takers pursuant to 40 U.S.C. § 501 are required to comply with the FAR, may have terms less than the term of the financing, and may require several agency approvals to be implemented.

# CHAPTER 4: LEGAL AUTHORITIES ENABLING FEDERAL AGENCIES TO PURCHASE POWER

**KEY POINTS FOR CONSIDERATION**

- While there are a wide-range of legal authorities available to federal agencies purchasing power, most federal agencies rely on GSA's 40 U.S.C. § 501 which provides for a maximum 10 year PPA term.
- Certain federal agencies (such as DOD, DOE, and WAPA) have longer-term legal authorities for purchasing power in certain situations.

The federal government purchases over $14.5 billion in utility services from over a thousand utility service providers.[47] To procure the necessary power, federal agencies utilize, and are subject to, a range of legal authorities.

This Chapter provides an overview of the legal authorities most commonly used by federal agencies to purchase power. Additionally, Appendix C provides a listing of additional legal authorities available to federal agencies to purchase power. This Chapter concludes with a description of the authorities most applicable to purchasing power produced by SMRs.

Additionally, please note that the focus of this Chapter is on federal contracting authorities. However, it will also be necessary to evaluate applicable state laws prior to purchasing power, as federal agencies are prohibited from expending funds to purchase electricity in a manner inconsistent with state law governing the provision of electric utility service.[48]

### 4.1 Summary of Key Federal Utility Acquisition Legal Authorities

As described in Section 2.2.3, a PPA is a long-term contract to sell electricity between a producer of electricity and a buyer. Federal agencies enter into PPAs to satisfy their power needs. PPAs are executed under a range of legal authorities.

Most federal agency power purchases are made through "areawide" or direct purchase contracts under the authority of the GSA. These contracts are executed under the authority of 40 U.S.C. § 501 and carry terms of five (5) to ten (10) years. The areawide contracts authorize the purchase of specified quantities of electricity at a specified price or tariff for a specified period of time and specific negotiated or regulatory determined rates. The authority is delegated to specific federal agencies (DOD and DOE), and GSA arranges for or delegates the authority to other federal agencies as outlined below.

Certain other federal agencies, such as DOD, DOE, and WAPA, have additional (sometimes longer-term) legal authorities. Additionally, as renewable energy projects have developed, additional legal authorities have been enacted to permit longer contract terms in certain instances.

Below is a list of key legal authorities that federal agencies use to purchase power. Additionally, Appendix C includes a more extensive listing of legal authorities used by federal agencies to finance power purchases.

| **Key Utility Acquisition Authorities Used by Federal Agencies** | |
|---|---|
| **GSA** | • 40 U.S.C. § 501 (FAR Part 41) authorizes GSA to prescribe policies and methods governing the acquisition and supply of utility services for federal agencies |
| **DOD** | • GSA delegated its authority under 40 U.S.C. § 501 to DOD to enable DOD to enter into utility service contracts not exceeding 10 years<br>• 10 U.S.C. § 2304 and 40 U.S.C. § 113(e)(3) authorize DOD to acquire utility services for military facilities<br>• 10 U.S.C. § 2922a authorizes DOD to purchase power generated on military bases or private property (but not other federal agency or governmental land) for a term not exceeding 30 years |
| **DOE** | • GSA delegated its authority under 40 U.S.C. § 501 to DOE to enable DOE to enter into utility service contracts not exceeding 10 years<br>• 42 U.S.C. § 7251, *et seq.* (the Department of Energy Organization Act) authorizes DOE to acquire utility services<br>• 42 U.S.C. § 2204 (the Atomic Energy Act of 1952) authorizes DOE to enter into new contracts or modify existing contracts for electric services for periods not exceeding 25 years for uranium enrichment installations |
| **Department of Veterans Affairs ("VA")** | • GSA delegated its authority under 40 U.S.C. § 501 to VA *for connection charges only* |
| **Other Federal Agencies** | • If utility services are required for over one year, federal agencies can request a delegation of authority from GSA under 40 U.S.C. § 501 in accordance with FAR Part 41.103(c) |

Federal agencies must comply with the requirements of FAR Part 41 when acquiring utility services (except for utility services produced, distributed, or sold by another federal agency – which follow the rules for interagency agreements – and several other exceptions not directly related to this Report).[49]

Federal agencies typically pay for utility services through annually appropriated operation and maintenance funds. The term of any federal government contractual commitment varies based upon the legal authority used to enter into the contract and most follow the FAR. Such contracts will be subject to cancellation and termination due to lack of appropriation, utility provider default, and the government's convenience. With certain limited exceptions, federal agencies are required to comply with state law governing the provision of electric utility service, including state utility commission rulings and electric utility franchises or service territories established pursuant to state statute, state regulation, or state-approved territorial agreements.[50]

The utility rate that a federal agency pays is either set by a regulatory body or is a negotiated rate. The negotiated rate can be based on federal agency demand and other factors. A stand-alone contract to purchase power only from an SMR will likely require the federal agency to negotiate a rate for the power delivered to the federal agency. A contract to purchase power from a utility where there is mix of power sources, and an SMR is one of the sources, will provide an agency with a "blended rate" for all of the types of power, and the agency will either negotiate a rate or, in the case of a regulated utility, will likely pay a regulated rate that is set by the utility based on the blended costs of the power sources.

### 4.2 GSA's Areawide Contracts and Separate Contracts

GSA is designated as the lead agency responsible for contracting for public utilities (electricity, natural gas, water, sewerage, thermal energy, chilled water, hot water, and steam) on behalf of the federal government.[51] GSA undertakes this responsibility in accordance with 40 U.S.C. § 501 and FAR Part 41.

GSA can enter into multi-year contracts for a term of up to 10 years for utilities. The contracts may take the form of areawide contracts or basic utility service agreements – referred to as "separate contracts" or single-point contracts.

| What is an Areawide Contract?[52] |
| --- |
| • A contract between GSA and a utility service supplier to cover utility service needs of federal agencies within the franchise territory of the supplier<br>• Each areawide contract includes an "Authorization" form for requesting service, connection, disconnection, or change in service<br>• A "franchise territory" is the geographical area that a utility supplier has the right to serve based upon a franchise, a certificate of public convenience and necessity, or other legal means |
| **What is a Separate Contract?[53]** |
| • An agreement (other than an Areawide Contract, an Authorization under an Areawide Contract, or an interagency agreement) to cover the acquisition of utility services |

Any federal agency having a requirement for utility services within an area covered by an areawide contract is required to acquire services under the areawide contract unless (i) service is available from more than one supplier, or (ii) the head of the contracting activity or designee otherwise determines that use of the areawide contract is not advantageous to the government.[54] Upon execution of an Authorization by a contracting officer and a utility supplier, the utility supplier is required to furnish services, without further negotiation, at the current applicable published or unpublished rates, unless other rates, and/or terms and conditions are separately negotiated by the federal agency with the supplier.[55]

Absent an areawide contract or interagency agreement, federal agencies are required to acquire utility services by separate contract subject to FAR Part 41 and the agency's contracting authority.[56] A contract exceeding a 1-year period, but not exceeding 10 years, may be justified and is usually required where:

- the federal government will obtain lower rates, larger discounts, or more favorable terms and conditions of service;
- a proposed connection charge, termination liability, or any other facilities charge to be paid by the federal government will be reduced or eliminated; or
- the utility service supplier refuses to render the desired service except under a contract exceeding a 1-year period.[57]

GSA has delegated its authority under 40 U.S.C. § 501 to DOD and DOE.[58] Additionally, GSA has delegated its authority for connection charges only to VA.[59] Should other federal agencies require a utility service contract for a period over one year (but not exceeding 10 years), such federal agency may submit a request for delegation of authority from GSA in accordance with FAR Part 41.103(c).[60] When acting under delegated authority, a federal agency must act in accordance with, and subject to, GSA's authority.

## 4.3 Interagency Agreements

Federal agencies use interagency agreements (e.g. consolidated purchase, joint use, or cross-service agreements) when acquiring utility services or facilities from other federal government agencies.[61] Such agreements must be in accordance with the procedures of FAR Part 17.502-2 and the Economy Act (31 U.S.C. § 1535). An example of an interagency agreement is described within the WAPA discussion in Section 4.6.

## 4.4 Additional DOD Authorities

Given DOD's need for power and its mission, Congress has adopted certain additional statutes applicable only to DOD; those relevant to power acquisition are further described in this Section and Appendix C.

### 4.4.1 Delegation of GSA Authority

DOD, operating under the above-described GSA utility authorities, can exempt itself from a GSA mandate when "an exemption is in the best interest of national security."[62]

### 4.4.2 DOD Power Purchases (10 U.S.C. § 2922a)

DOD has authority under 10 U.S.C. § 2922a to enter into certain long-term contracts with private developers for electric power produced on military installations or private property. Under the authority of 10 U.S.C. § 2922a, a developer may install an energy production facility on a military installation under a long-term agreement with a military department.

After installation, the developer would own, operate, and maintain the facility for the life of the contract. The military department would purchase the electric power generated by the facility and pay for some or all of the facility through its power payments over the life of the contract. Such contract allows the military department to acquire electric power without providing the capital costs at the time of construction of the facility. The costs of the contract for a particular year may be paid from annual appropriations for that year.[63]

Key provisions of 10 U.S.C. § 2922a are as follows:

| | |
|---|---|
| **Maximum Contract Term** | 30 years[64] |
| **Authority** | Provision and operation of energy production facilities on real property under the Secretary's jurisdiction or on private property and the purchase of energy produced from such facilities[65] |
| **Types of Energy Sources** | Applies to any type of energy production facility |
| **Location of Facility** | Applies to a facility on DOD or private land.[66] According to DOD policy, it does not apply to a facility on non-DOD Federal property, e.g., public domain lands not withdrawn for military uses, or on non-Federal public property, e.g., state or local government property[67] |

Any contracts under 10 U.S.C. § 2922a must be approved in advance of award by the Secretary of Defense.[68] The DOD approval authority has been re-delegated to the Deputy Undersecretary for Installations and Environment.

#### 4.4.3 Enhanced Use Leases (10 U.S.C. § 2667)

10 U.S.C. § 2667 authorizes the Secretaries of the military services to lease non-excess property through a lease referred to as an Enhanced Use Lease ("EUL") or a Site Development Lease. EULs must include payment (in cash or in-kind) by the lessee of consideration for an amount not less than the fair market value of the lease interest.[69]

The term of an EUL can be for more than five (5) years if the Secretary concerned determines that a lease for a longer period will promote the national defense or be in the public interest.[70] As further described in Section 4.8 below, combining EULs with PPAs may have budgetary scoring implications. Hence, the EUL can be used for siting but may be difficult to use for purchasing power produced by an SMR. Most energy EULs are for terms exceeding thirty (30) years.

#### 4.4.4 Utility Energy Service Contracts (10 U.S.C. § 2913)

Under 10 U.S.C. § 2913, a utility may install, maintain, and finance energy and energy related improvements for DOD departments through a Utility Energy Service Contract ("UESC"). The utility is able to recover the resulting energy savings to pay for the project over a period of time. Payments made by the agency equate to the cost savings incurred by the conservation improvement.

### 4.4.5 Utility Conveyance (10 U.S.C. § 2688)

In accordance with 10 U.S.C. § 2688, a Secretary of a military department may convey all or part of a utility system under the jurisdiction of the Secretary to a municipal, private, regional, district, or cooperative utility company or other entity.[71] In return, the new owner agrees to operate and maintain the utility system, as well as undertake upgrades and improvements to the system over the course of the contract, which typically lasts for fifty (50) years.

In exchange for the conveyance, the Secretary may require as consideration an amount equal to the fair market value (as determined by the Secretary) of the right, title, or interest of the United States conveyed.[72] The consideration may take the form of a lump sum payment or a reduction in charges for utility services at the military installation at which the utility system is located.[73] The maximum term of a utility contract under this authority is fifty (50) years.[74]

## 4.5 Energy Savings Performance Contracts (42 U.S.C. § 8287) and Utility Energy Service Contracts (42 U.S.C. § 8256)

Under an Energy Savings Performance Contract ("ESPC"), federal agencies may enter into contracts for the purpose of achieving energy savings and benefits ancillary to that purpose. The maximum term of an ESPC is twenty-five (25) years.[75] Under an ESPC, the contractor is responsible for the costs of implementing energy savings measures, including the costs of 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.[76] The Federal Energy Management Program provides a software program on its website setting forth the escalation rates for the ESPCs.[77]

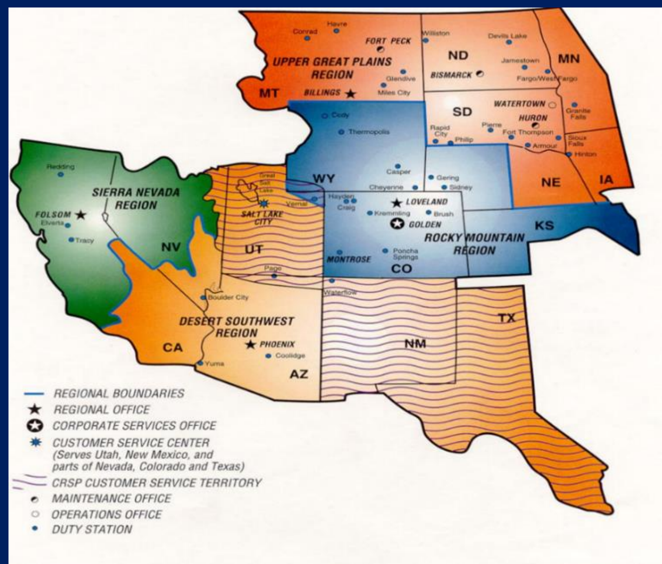
Similarly, utilities may also enter into contracts for energy savings conservation measures with federal agencies under an UESC. In addition to the DOD-specific UESC authority described in Section 4.4.4 above, other federal agencies may also participate in UESCs pursuant to the requirements of 42 U.S.C. § 8256.

## 4.6 Western Area Power Administration Authorities

WAPA is one of four PMAs within DOE whose role is to market and transmit wholesale electricity from multi-use water projects. WAPA's service area encompasses a 15-state region of the central and western United States where its more than 17,000 circuit mile transmission system carries electricity from 56 hydropower plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers, and the International Boundary and Water Commission. WAPA sells power to preference customers such as federal and state agencies, cities and towns, rural electric cooperatives, public utility districts, irrigation districts, and Native American tribes.[78]

**Figure 12**

**WAPA Service Territory**



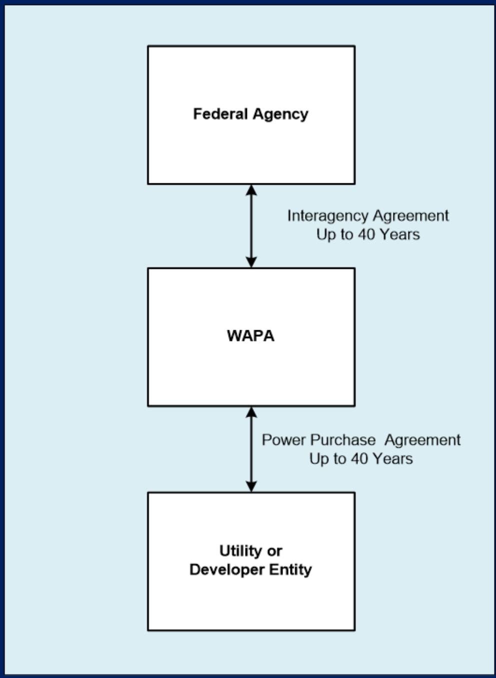

In marketing electricity, WAPA must follow many laws, regulations, and policies. Section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. § 485h(c)) ("Reclamation Act") established a maximum term of 40 years for WAPA's power sales contracts (except Boulder Canyon, which has a 50-year contract term under the Hoover Power Allocation Act of 2011). The Reclamation Act also identifies certain types of prospective customers who must be given preference in federal power sales, such as municipal and public utility districts, water and irrigation districts, state and federal entities, Native American tribes, and rural electric cooperatives. The Reclamation Act also specifies the repayment responsibility of power users – any sale of electric power must produce enough power revenues to cover power users' share of annual operation and maintenance project costs, plus interest on their share of the construction investment.

WAPA transactions with federal agencies also contemplate the use of the Economy Act (31 U.S.C. § 1535), which allows federal agencies to enter into "interagency agreements" with other federal agencies. The combination of the Reclamation Act and Economy Act authorities enable a federal agency within WAPA's service territory to enter into a contract to purchase electric services for up to 40 years.

In order for WAPA to facilitate a purchase of power produced by an SMR, WAPA would enter into agreements with two parties – (i) an Interagency Agreement with a federal agency and WAPA, and (ii) a PPA between WAPA and the utility or developer entity. Costs incurred under the PPA are passed through to the federal agency in accordance with the Interagency Agreement. The federal agency pays WAPA to develop the PPA (one-time cost) and a negotiated annual charge for contract administration to cover the long-term administrative costs.[79]

**Figure 13**

**Summary of WAPA Transaction Structure**




In most cases, the PPA and/or Interagency Agreement will include the following provisions:

- **Direct Billing.** Requirements that (i) the utility/developer entity bill the federal agency receiving the power, and (ii) the federal agency receiving the power pay the utility/developer entity directly. This process decreases administrative costs of the project.

- **Accountability.** Provisions to hold the utility/developer entity accountable for its obligations (i.e. if the generation fails during the term of the contract) and the federal agency accountable for its obligations (i.e. payment contingent on appropriations, site lease, etc.).

- **Off-Ramp Provisions.** Off-ramp provisions if the project cannot go forward, such as if the utility/developer entity cannot obtain licensing for the SMR, is unable to obtain a site lease for the development of the facility, is unable to obtain an interconnection agreement with the local utility, or cannot obtain financing.

- **Applicability of Federal Law.** Applicable federal laws (such as the Freedom of Information Act, Equal Employment Opportunity laws, Contract Dispute Act, etc.) will be referenced.

- **Other Provisions.** Other key provisions will be included, such as prohibitions on indemnifying the other contracting party or engaging in binding arbitration.

WAPA agreements require that all risk of delivery and payment is the responsibility of the federal agency receiving the power. As such, WAPA's role is a conduit to assist with the power purchase consistent with WAPA's legal authority and role in the western United States.

The transaction structure outlined in this Section requires that the utility/developer entity selling the power, WAPA, and the federal agency purchasing the power work closely together. The following example of a Navy/WAPA transaction had support from the top levels of the Navy and WAPA, thereby assisting the project to be completed in a timely manner (as many offices within each organization needed to review and approve the specifics).

**Example: 30 Year Navy Power Purchase with WAPA Assistance**

Through an Interagency Agreement, WAPA is assisting 14 Navy installations in California to acquire renewable power by procuring and awarding long-term contracts to meet the requirements of the Navy for renewable energy from new generation sources.

The Interagency Agreement identified the authorities relied upon by the parties are the Economy Act, the Reclamation Act, and 10 U.S.C. § 2922a. The Economy Act authorizes the head of any governmental agency to place orders with a major organization unit in the same agency or in another agency for goods or services if the order is in the best interest of the government and cannot be provided as conveniently or as cheaply by a commercial enterprise. This provides the authority for WAPA to provide assistance to the Navy. WAPA's ability to purchase power on a long-term basis on behalf of the Navy provides the Navy with needed price predictability and stability.

Under the Interagency Agreement, WAPA:

1. Supports the Navy to define requirements, key project objectives, unique project requirements, and performance expectations;
2. Conducts market research, development, and implementation of acquisition strategies responsive to program and project requirements;
3. Develops requests for proposals and solicit renewable energy and energy-related services;
4. Awards renewable energy contracts and administer such contracts on behalf of the Navy;
5. Invoices the Navy for administrative and energy costs;
6. Pays the renewable energy suppliers; and
7. Conducts annual reviews of performance under the Interagency Agreement and related contracts, including compliance with legal and regulatory obligations under the renewable energy contracts.

In turn, the Navy:

1. Makes sure WAPA is aware of all terms, conditions, and requirements necessary to comply with DOD and Navy statutes, regulations, and directives;

2. Obtains appropriate agency approval for all transaction documents, including those related to renewable energy supply contracts;
3. Provides funding for all renewable energy products and services contracts;
4. Completes required environmental actions including those related to mitigation;
5. Cannot authorize work, change any contractual documents, modify the authorized scope of work, or authorize accrual of costs, except as expressly authorized by WAPA;
6. Advises WAPA immediately of any problems or conditions regarding performance by a renewable energy supplier;
7. Within thirty (30) days, receive, inspect, and accept in a writing forwarded to WAPA the services and procured renewable energy;
8. Executes all responsibilities in a timely fashion in accordance with the Prompt Payment Act (31 U.S.C. Chap. 39);
9. Supports contract close-out functions, including appropriate funding for WAPA assisted service fees, satisfaction of settlement agreements and claims, and acceptance of any excess funds returned by WAPA;
10. Acts as a good steward of the Navy's funds in compliance with applicable laws;
11. Designates and provides contact information for the appointed Defense Accounting Official;
12. Ensures nominated personnel obtain the necessary training for contracting officer appointment, maintain contracting officer eligibility, and promptly notify WAPA of any new contracting officer; and
13. Conducts annual reviews of performance under the Interagency Agreement and related contracts.

It is specifically noted in the Interagency Agreement that the Navy must properly carry out its responsibility to ensure deliverables are received and the quality of the deliverables is acceptable. WAPA, as part of the Interagency Agreement, encourages the Navy to conduct site visits, inspections, and perform close review of all deliverables to ensure the government receives the contract value.

## 4.7 Agency-Funded Projects through Appropriated Funding

In lieu of using the aforementioned authorities to purchase utilities, federal agencies also have the discretion to pay for the development and continuation of an SMR project through budgeted funds which the federal agency then owns and operates. However, in the current budget environment, appropriated funding is constrained and cannot meet all the needs of the federal government on its own.

## 4.8 Office of Management and Budget Scoring Issues and Small Modular Reactors

Scoring is the way the White House Office of Management and Budget ("OMB") accounts for and controls agency budgets on behalf of the White House. Since the federal government has no capital budget, and therefore fails to link borrowings (debt) with expenditures (either for annual expenses or purchases of capital assets), OMB controls spending by controlling the amount of obligations that an agency can make (budgetary authority) regardless of whether the payments necessary to satisfy the obligations (outlays) will be made in the current year or in an out-year as a result of a long-term contract. Through the use of OMB Circular A-11, OMB draws a distinction between capital and operating costs and leases through a series of tests. If OMB determines that a project is characterized as a capital lease, the amount of money that may be spent under the contract (regardless of the year of actual payment) must be available (scored) in the agency's budget during the year in which the contract is executed and the obligation incurred. The general rule for scoring is that when an agency enters into a purchase or lease that is characterized as a capital lease, the contract will be scored in the year in which the budgetary authority is first made available in the full amount of the government's total estimated legal obligations over the entire course of the lease or the purchase. In contrast, if the project is characterized by OMB as being an operating lease, then the agency only needs budget authority on a year-by-year basis, similar to a commercial mortgage.

OMB scoring is an in-depth review of any project where the federal government is the purchaser of a good or service on federal land. The scoring rules are complex, and this Section should only be treated as an introductory outline of the issues.

For example, if DOD signs a ten year contract in 2016 to pay $3 per year, OMB can score the contract one of two ways. OMB can require DOD to score $30 in 2016 (10 years x $3) and nothing for 2017 through 2025 (in the case of a capital lease), or OMB can require DOD to score $3 each year from 2016 to 2025 (in the case of an operating lease). As a practical matter, few agencies can afford the first (capital) method of scoring the acquisition of a capital asset; they need the missing $27 now, not over a nine year period.

Appendix B of OMB Circular A-11 details the scoring rules applicable to leases and lease-purchases.[80] Key definitions are as follows:

| **Key Scoring Definitions[81]** | |
|---|---|
| **Operating Costs** | • Costs that keep the government "operating" |
| **Capital Costs** | • Expenditures that are equivalent to the *purchase* of a capital or fixed asset (such as a building, piece of machinery, aircraft carrier) |
| **Capital Assets** | • Land, structures, equipment, intellectual property that are used by the federal government and have an estimated life of two years or more |
| **Lease-Purchase** | • Type of lease in which ownership of the asset is transferred to the government at or shortly after the end of the lease term. Such a lease may or may not contain a bargain-price purchase option. |
| **Capital Lease** | • Any lease other than a lease-purchase that does not meet the criteria of an operating lease. |

| Key Scoring Definitions[81] | |
|---|---|
| **Operating Lease** | • A lease that meets all the criteria listed below. If the criteria are not met, the lease will be considered to be a capital lease or a lease-purchase, as appropriate. Multi-year service contracts (e.g., grounds maintenance) and multi-year purchase contracts for expendable commodities (e.g., aspirin) are not considered to be operating leases.<br>o Ownership of the asset remains with the lessor during the term of the lease and is not transferred to the government at or shortly after the end of the lease term;<br>o The lease does not contain a bargain-price purchase option;<br>o The lease term does not exceed 75 percent of the estimated economic life of the asset;<br>o The present value of the minimum contractually required payments over the life of the lease does not exceed 90 percent of the fair market value of the asset at the beginning of the lease term;<br>o The asset is a general purpose asset rather than being for a special purpose of the government and is not built to the unique specification of the government as lessee; and<br>o There is a private sector market for the asset. |

Appendix B of OMB Circular A-11 states in part:

> Agencies should consult with OMB in cases where enhanced use leases and public-private partnerships are involved. Public-private partnerships should not be used solely or primarily as a vehicle for obtaining private financing of Federal construction or renovation projects. Such transactions should be used only when they are the least expensive method, in present value terms, to finance construction or repair. Agencies should consult with OMB in cases where a contract requires a private contractor to construct or acquire a capital asset solely or primarily to provide the service to the Government to determine the appropriate treatment or obligations.

Thus, in evaluating any energy or SMR project where the federal government is a purchaser of the power, it will be necessary to determine what scoring rules apply. For example, an agency entering into a PPA to receive power that is not generated on federal land and otherwise meets the conditions described above will likely (depending on all factors) only score the amount due under the first year of the contract. Alternatively, if the power source is located on federal land and/or has no other non-federal purchaser of that power, it is likely that the project will be scored as a capital lease with the full amount of the government's payments scored in the year of contract execution. Further, if the project is built on federal land of one agency but the power is purchased by another agency or even the same agency on separately owned land, there is likely no capital lease scoring.

Please note that some exceptions exist to these general outlines (such as 10 U.S.C. § 2922a), and each case must be reviewed on the facts of the project. How the project is scored by OMB in accordance with OMB Circular A-11 will influence whether or not the agency can proceed with the contract.

## 4.9 Most Likely Legal Authorities to Rely Upon for Power Purchases from a Small Modular Reactor

The most likely legal authorities that will be relied upon by federal agencies to purchase power from an SMR are as follows:

- GSA's 40 U.S.C. § 501, which will allow for a contract up to a 10 year term;
- Interagency Agreements, coupled with a PPA, which will allow federal agencies to take advantage of the authorities or power sources of other federal agencies or departments (i.e. DOE may enter into an Interagency Agreement with WAPA, or another PMA, to take advantage of its ability to enter into up to 40 year PPAs); and
- 10 U.S.C. § 2922a (for DOD only) which will allow for up to a 30 year term assuming the project is constructed of DOD or privately owned land.

DOD components may also have the opportunity to take advantage of additional authorities depending upon the location of the SMR.

## 4.10 Impediments to Utilizing Certain Other Existing Legal Authorities for Power Purchases from a Small Modular Reactor

While there are a wide-range of legal authorities that enable the federal government and its various departments to purchase power, each of these authorities is limited in its application. The length of contract term represents a significant constraint. The most common authorities are limited to a maximum of a 10 year contracting term – which makes financing larger investments more challenging. Additionally, as described above, certain legal authorities are applicable only in certain situations (i.e. renewable energy) or for power generated on a federally-owned facility. For example, current guidance requires that PPAs associated with an ESPC or UESC be for power attached to a facility being improved, rendering these authorities moot for any SMRs being considered off-site.

In situations where longer term contracts are available, federal agencies are often challenged by balancing the needs of project financiers with the requirements and restrictions associated with budget scoring. Commitments made for satisfying the investment community often trigger characterizing the project as being a capital lease, thereby requiring budget authority up-front in the year of contract execution. Since energy purchases are treated as an operating expense, requiring budget authority up-front will render a project unaffordable, as appropriations will be required well ahead of outlays for the consumption of electricity.

### KEY CHAPTER TAKEAWAYS

- It is important to understand and evaluate the advantages and drawbacks of the various legal authorities when selecting the appropriate power contracting authority. Additionally, other considerations, such as OMB scoring and the necessity of having the PPA with the federal agency in order to obtain financing, should also be evaluated.

- While there are a range of legal authorities federal agencies may use to purchase power, most often GSA's 40 U.S.C. § 501 is used, limiting PPA terms to 10 years.

- DOD's 10 U.S.C. § 2922a has been used in limited circumstances by DOD to enter into 30 year PPAs.

- A federal agency located within WAPA's jurisdiction may leverage WAPA's long-term contract authority by entering into an Interagency Agreement with WAPA and allowing WAPA, in turn, to enter into a PPA with a power provider on such federal agency's behalf for a term of up to 40 years.

# CHAPTER 5: CONSIDERATIONS FEDERAL AGENCIES EVALUATE WHEN MAKING POWER PURCHASE DECISIONS

**KEY POINTS FOR CONSIDERATION**

- Federal agencies, like all buyers of electricity, need to align purchases of power with demand for power to avoid having to hastily procure electricity when demand unexpectedly exceeds contracted supply.
- Federal agencies, like all buyers of electricity, should consider how power purchase arrangements will affect future expenses on power. Given the complexity of power markets, this requires thorough analysis.

Power purchase decisions are complicated and important choices. Given the range of arrangements available, a potential federal off-taker should carefully consider its options. A purchase decision must start with an estimate of the off-taker's demand to understand what its power needs are. Projects that can meet those needs should be judged for their likelihood of being successfully completed and reliably delivering power over the long-term. In addition, the cost of the source of power should be evaluated against alternative sources.

This Chapter identifies the primary economic considerations federal agencies should evaluate when making SMR power purchase decisions.

## 5.1 Off-taker Demand Profile

A potential off-taker should plan on entering into purchasing agreements that meet its likely demand. Depending on the terms of an agreement, an off-taker could be stuck with making payments for power it does not use. On the other hand, if an off-taker underestimates its demand, it may then have to hastily procure costly power to meet its needs. Since power is often purchased through long-term contracts, a potential off-taker has to estimate its likely demand for power long into the future.

At a minimum, inputs to a demand profile should include the following items:

| Minimum Inputs to a Demand Profile |
|---|
| • The off-taker's historic demand profile (by time of year and time of day)<br>• Historic energy bills<br>• Historic staffing and other factors that have affected demand<br>• Planned staffing levels or other factors that may drive demand<br>• Historic and forecasted demand in the local market, if the project will sell some of its production into a competitive market |

To create a forecast, a potential off-taker should use past trends as a basis for the future, while also accounting for new circumstances in the future which may cause past trends to change. The historical analysis should help identify what drives demand. Different facilities may have different drivers of demand.

| Examples of Drivers of Demand |
|---|
| • Historic demand increases may correlate strongly with staffing levels. Thus, staffing plans may be a key driver of estimated demand.<br>• Planned capital works may affect demand. For example, a federal site may be planning a retrofit which will significantly reduce power consumption for air conditioning in the summer.<br>• Technology use may be a strong driver of demand. For example, a site housing large information technology systems may increase its demand as new systems are installed. |

The demand profile will be a key input to the analysis of a project's impact on rates.

## 5.2 Understanding Performance Risks

Any power project faces challenges in being completed, starting in early development and running through the end of construction. Some of these challenges may be greater for SMRs than for other technologies due to nuclear projects' environmental implications and technical complexity.

SMRs, like all nuclear projects, will have to be licensed by the NRC. There are various processes employed by NRC to issue permits and licenses, as identified in 10 C.F.R. Part 50 and 10 C.F.R. Part 52. In addition to the NRC approval process, key concerns of an SMR project include the following items:

| Key Performance Risk Concerns for SMRs | |
|---|---|
| **1. Regulatory Permissions** | • In addition to the NRC approval process, other regulators, such as state Public Utility Commissions, the Federal Energy Regulatory Commission ("FERC"), and the Environmental Protection Agency, may also be involved, as |

| Key Performance Risk Concerns for SMRs | |
|---|---|
| | well as permits from other state and local agencies. |
| **2. Local Political Support** | • People living near planned nuclear facilities often object to having such facilities nearby or having nuclear materials transported or stored nearby. This can lead to resistance from municipal or state governments.[82] |
| **3. Financing Risk** | • Financing may not be available at the expected times or expected terms to allow projects to proceed. This may be due to changes in the general financial or economic environment, the financial health of lenders, or other factors. |
| **4. Performance Risk** | • Large capital projects often face unexpected delays or cost overruns. Post-completion performance is also a critical concern given the long expected operating periods of energy production facilities. |
| **5. Interconnection Risk** | • Delivery of power to the off-taker may require the construction of lines to "plug" the project into the nearest point of the grid or making improvements to various parts of the grid to allow power to flow from where it is produced to where it will be used. If interconnection works are not completed on time, then a project may not be able to produce as much power as planned. This may also result in congestion charges which increase the price of transmission services in certain power markets. |

The above considerations are relevant to the development of all power projects, but are of particular importance with newer technologies like SMRs. Delays in the start of commercial operations or less-than-expected output can be costly to off-takers as large amounts of baseload power may need to be secured on short notice or provided for on a standby basis. Therefore, off-takers will typically exercise caution in the selection of power sources.

## 5.3 Performing an Economic Impact Analysis

A potential federal off-taker of SMR power should consider the relative economic attractiveness of different power purchase options. It is not enough to see if an agency can afford an option; the option should be weighed against likely alternatives. This requires making assumptions about likely power supply options in the absence of an SMR project. This Section provides an overview of key considerations in economic impact analysis.

A project's economics should be analyzed in terms of "avoided cost." This means determining whether a potential project will cost less than the likely alternative option, which is referred to as the "avoided cost." For federal off-takers, the avoided cost will probably be purchases from the local power provider using the existing power source mix that the utility uses to supply power to the area. It is important to note that not all utility costs are likely to be avoided. Even after building a large on-site project that bypasses the utility, off-takers typically rely on the utility for at least a small part of their power needs. The charges paid to the utility in that case are called "residual utility rates."

It is possible that a potential project could cost more than the avoided cost, in which case the potential project would be less desirable economically. While a potential project may or may not provide prospective cost savings, the decision to enter into a long-term purchase contract may be influenced by other factors, such as diversity of supply, predictability of costs, or greater energy security in the time of crisis.

The key element in estimating avoided cost is estimating likely energy prices in the future, or utility rate analysis. Utility rate analysis should cover all components of electricity rates. Besides the cost of energy itself, rates may include charges for transporting electricity and charges for maintaining the grid.

Economic impact analysis should start with understanding the relevant market and regulatory structures. As described in Appendix B, states vary significantly in terms of how power is bought and sold. One of the key considerations is how regulation and market dynamics determine prices and charges for a given project.

#### 5.3.1 Charges for Electricity Production

Whether in regulated or deregulated markets, rates may include charges for the generator's cost of producing power and charges reflecting demand for power at different times.

| Types of Charges for Electricity Production | |
|---|---|
| **Energy Charges** | • "Pure" electricity charges, covering the costs of power production.<br>• May vary by time of day due to differences in the marginal cost of power production. For example, solar plants may produce more energy around midday, increasing supply and reducing the price of power on the market at that time.<br>• In regulated markets, these charges are set by regulators as part of allowed rates.<br>• In deregulated markets, generators may agree on an energy charge through a PPA or submit bids in competitive markets. |
| **Demand Charges** | • Charges for supplying power at times of peak demand in the market (a scarcity price).<br>• Recognizes that utilities need to have sufficient capacity available to meet demand, and there is a cost to availability.<br>• Can be peak times of day, week, or year. |

| Types of Charges for Electricity Production | |
|---|---|
| | • In regulated markets, regulators may authorize a fixed structure for raising prices at periods of peak use.<br>• In markets with wholesale competition, prices will rise during periods of high demand as utilities and other buyers outbid each other to meet their requirements.[83] |

### 5.3.2 Charges for Transporting and Delivering Power

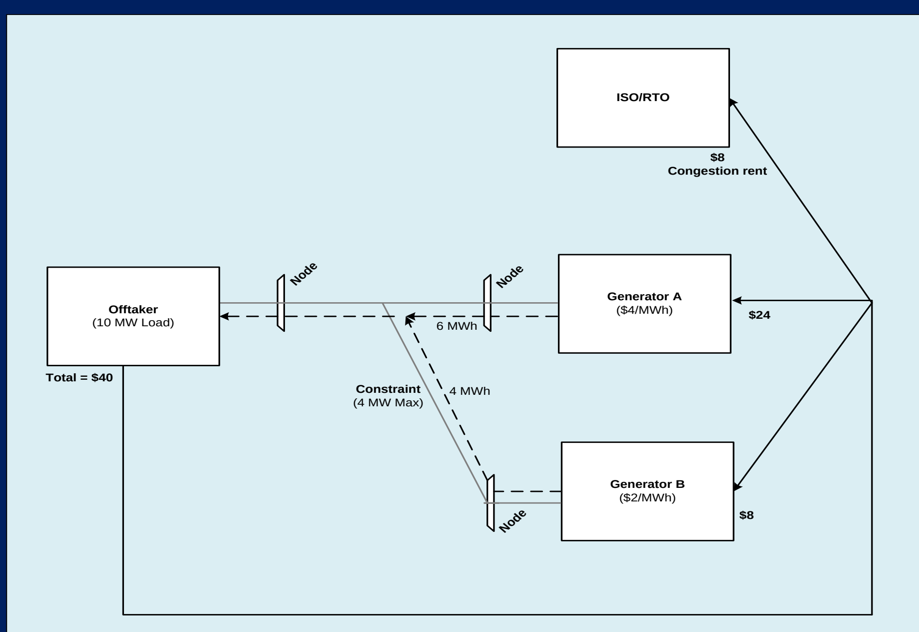
Costs are incurred in moving power through the power sector value chain. These include transmission charges for moving power from generators to utilities and distribution charges for delivery of power to consumers.

Transmission charges cover the cost of using the transmission grid to move power over long distances at high voltage. Some markets have a fixed transmission charge that is approved by a regulator. Other markets determine transmission charges through location marginal pricing ("LMP"), a competitive market pricing mechanism. Wheeling charges may also apply.

- **Location Marginal Pricing:** All markets served by independent system operators ("ISOs") or regional transmission organizations ("RTOs") have LMP pricing. LMP markets are managed by the ISOs and RTOs and based on congestion and demand in different parts of the grid. Figure 14 illustrates how LMP can impact the price of power by creating a charge for congestion which must be paid by the off-taker ("congestion rent").

**Figure 14**

**Location Marginal Pricing**[84]



Congestion may also force an off-taker to buy some of its power from more expensive sources if the congestion is located such that it reduces delivery of power from a cheaper source.

- **Wheeling:** When power crosses from one territory to another, wheeling charges apply. This can include moving power from deregulated utility to another or moving power between a regulated and deregulated market. Wheeling charges are generally set by regulators and aim to cover the cost of building and operating the transmission grid through transmission charges.

Distribution charges cover the cost using the distribution grid to move power at low voltage. These include the cost of building and maintaining lines and commercial services such as metering, billing, and others. These charges are generally approved by state regulators. Even if retail power is purchased from a competitive retailer in a deregulated market, retail prices will include the cost of a regulated distribution charge that the retailer pays to move power over the grid.

#### 5.3.3 Standby Charges

Standby charges may be incurred if an off-taker uses self-generation or buys power from a power purchase agreement that is "behind the meter" – in other words, if the power plant is located on the off-taker's site such that power is delivered to the off-taker without passing through the grid. From the distribution utility's viewpoint, this looks like a reduction in demand. However, if the on-site power plant is offline, the utility will need to supply additional power and thus needs to maintain capacity to do so. Standby charges permit the local utility to charge the off-taker for the cost of maintaining generation assets and the grid such that the off-taker can use them when needed.

Different utilities provide different types of standby services. Some of these services may be attractive for off-takers of on-site PPAs or self-generators, as they provide backup or supplementary power from the grid. Standby services typically include some or all of the following:

| Typical Standby Services[85] | |
|---|---|
| **Backup Power** | • Provides electricity when on-site generation is unavailable due to an unplanned outage |
| **Maintenance Power** | • Provides electricity when on-site generation is unavailable due to a planned outage, such as for routine maintenance |
| **Supplemental Power** | • Provides electricity for customers whose on-site generation typically does not meet all their electricity needs |
| **Economic Replacement Power** | • Provides electricity from the grid when it is cheaper than electricity from on-site generation<br>• Typically applies to on-site generation technologies that have high marginal costs of power production, such as diesel generators which incur fuel costs |

Standby charges typically consist of a fixed charge to make standby power available and then variable charges depending on the quantity and type of service provided. These charges are described below.

| Typical Standby Charges | |
|---|---|
| **Capacity Reservation Charge** | • Covers the utility's cost of making generation capacity available for standby services |
| **Capacity and Energy Charges** | • Covers the cost of electricity provided for backup power |
| **Maintenance Capacity Charge** | • Covers the cost of electricity provided for maintenance power |
| **Facility Charges** | • Cover the costs of delivering power (distribution) and may also include a fixed component for maintaining a distribution connection for the consumer |

Standby charges are approved by state regulators and can vary across utilities in the same state.

### 5.3.4 Calculating Avoided Cost

Avoided cost should be analyzed in present value terms to convert the value of a stream of financial flows over time to a single value in the present. To calculate the present value, the streams of cash flows in each year of the potential project have to be estimated. This allows for comparison of all the payments under the avoided cost scenario with all the payments during the project's life. The avoided cost scenario can also be thought of as the "base case," since it represents a scenario in which the current power purchasing arrangement remains in place.

Seven steps for calculating the present value of cost avoidance are explained below.

1. **Determine Base Case Escalation:** This step estimates the likely rate of growth in electricity rates from the local utility. The escalation rate should reflect likely drivers of electricity prices such as inflation, utilities' future debt payments, and what rates are likely to be allowed by regulators. The time period for the estimate should include the entire life of the project under consideration.

2. **Calculate Base Case Rates:** This step estimates the likely rates under the base case scenario. This is done by applying the estimated growth rates (estimated in the previous step) to the current rates, thus arriving at an estimate of future rates under the base case.

3. **Determine Residual Utility Rates:** Review of the applicable regulations and utility practices should allow an estimation of which utility charges will still apply after the project is operational (such as standby charges). The escalation rate from Step 1 can then be applied to these to forecast them over the life of the project.

4. **Determine Project Rates:** Calculate a project starting rate (first year of operations) and escalation rate over the project's life. This can be done by analyzing financial data on the

project or, in the case of a competitive tender, asking bidders to submit rates in their bid. The escalation rate can then be applied to the starting rate to forecast rates over the life of the project.

5. **Calculate Base Case Electricity Costs:** Multiply the base case rates (from Step 2) by the total expected consumption of the site on an annual basis to calculate base case electricity costs for each year.

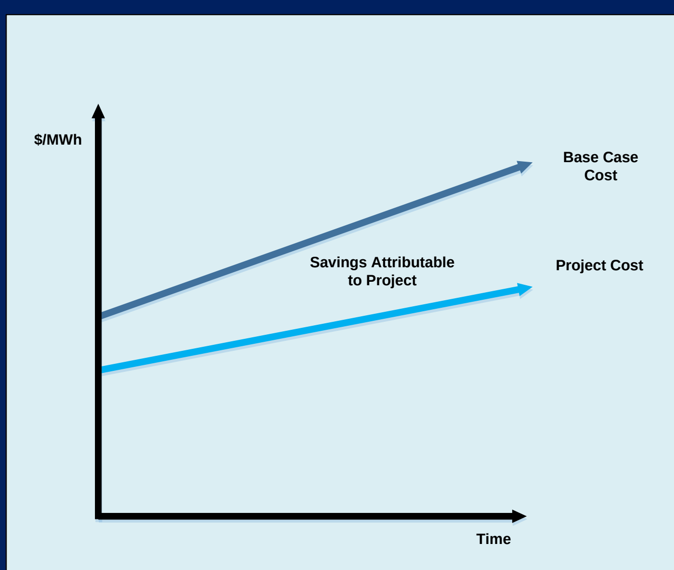
6. **Calculate Post-Project Electricity Costs:** Multiply the expected project rates from Step 4 by the expected generation from the project to get the expected project electricity cost for each year. Similarly, multiply the expected residual utility rate (from Step 4) by the expected consumption of power form the utility to get the residual utility cost for each year. Then, add the project electricity cost and residual electricity cost together for each year to get the total post-project electricity costs for each year.

7. **Calculate Present Value of Cost Avoidance:** Subtract the total post-project electricity costs (Step 6) from the base case electricity costs (Step 5) to get the cost avoidance for each year. If the cost avoidance is positive in a given year, then the project is less costly in that year. If the cost avoidance is negative, then the project is costlier in that year. For each year, discount the annual differences to the present day using the current United States Government discount rate.[86] Then, sum all the annual discounted values to calculate the present value of the cost avoidance**.**

If the present value of cost avoidance is positive, then the project is the less costly option. If the present value of the cost avoidance is negative, then the project is the costlier option. Figure 15 illustrates an analysis of avoided cost in which the project is the less costly option in all years. The savings from the project are represented by the area between the lines.

**Figure 15**

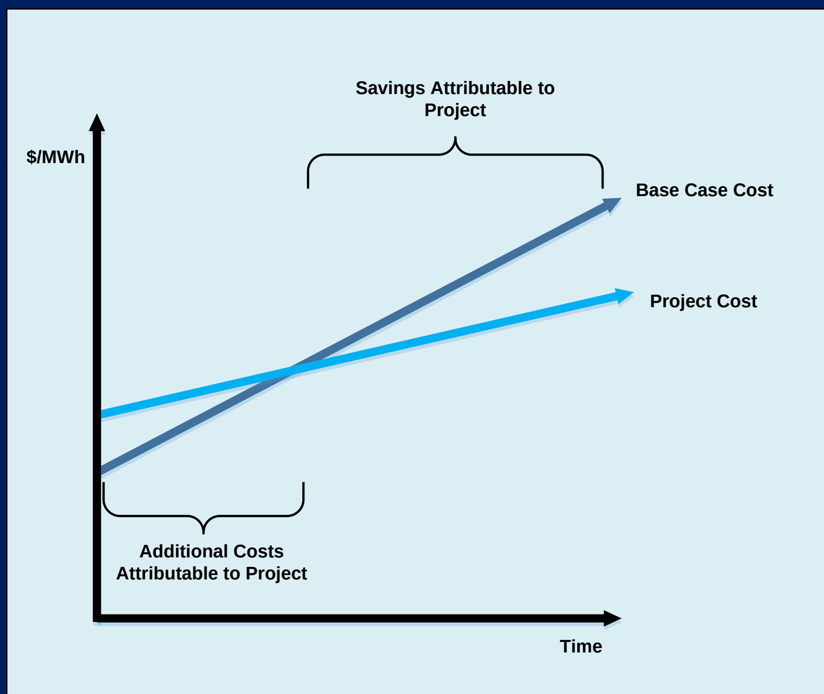
**Avoided Cost Analysis for Project That is Less Costly in All Years**



The project could be the costlier option in some years, but still be the less costly option when all years are considered together in terms of present value. This is illustrated in Figure 16. The triangle on the right side shows the period of positive cost avoidance, while the triangle on the left shows the period of negative cost avoidance.

**Figure 16**

**Avoided Cost for Project that is Costlier in Some Years**




Entering into a power purchase agreement provides the off-taker with greater certainty of future power costs by providing insulation from market volatility. For this benefit, off-takers may find it worthwhile to enter into a power purchase agreement as part of a long-term strategy to manage power cost risks.

Even if a project is more expensive than the base case (the present value of cost avoidance is negative), a federal off-taker may still want to pursue the project for other reasons. These include predictability of electricity rates, diversification of generation sources, or supporting the financing and development of an innovative technology.

## KEY CHAPTER TAKEAWAYS

- Estimating future demand for electricity is a complex process which requires analysis of historic consumption and forecasting of future demand based on expected staffing, capital works, and technology use, among other factors.

- When power purchases require construction of new power projects, performance risk should be minimized to ensure power projects are available to deliver electricity on schedule and at the desired quantity and quality.

- An economic impact analysis aims to compare future spending on power under a new option against continuation of the status quo. Doing this requires the analysis of many drivers of cost which vary across utilities and states. Important cost drivers include energy charges, transmission and distribution charges, and standby charges.

# CHAPTER 6:
# NOTIONAL PROJECT – THE IDAHO SMR PROJECT

**KEY POINTS FOR CONSIDERATION**

- This Chapter applies the concepts described earlier in this Report to the Idaho SMR Project as a case study. The concepts described in this Chapter can also be applied and considered for other projects around the country.
- The Idaho SMR Project has a diverse set of stakeholders, including DOE, municipal utilities, federal off-takers, private firms, and potentially WAPA. The involvement of these stakeholders will require complex, but feasible, legal agreements to facilitate the project.
- Power from SMRs may not be the least costly source of power for federal off-takers. However, price is not the only consideration in choosing how to purchase power.

## 6.1 Overview of the Idaho SMR Project

UAMPS explains the purpose and need of the Idaho SMR Project as:

> ...to provide for additional mid-sized baseload electrical generating capacity to meet the expected future needs of UAMPS' members. UAMPS has determined that new carbon free baseload capacity is necessary to replace the expected retirement of coal fired generating assets and that the UAMPS members need to have a carbon-free baseload generating asset as part of a balanced portfolio of generating assets. UAMPS SmartEnergy analysis concluded that small modular nuclear reactor technology is an important option for future consideration.[87]

### 6.1.1 Key Parties

Key parties involved with the Idaho SMR Project are as follows:

| Party | Role |
|---|---|
| UAMPS | UAMPS will be the Sponsor for the Idaho SMR Project. UAMPS was established in 1980 under the Utah Interlocal Cooperation Act, Title 11, Chapter 13, Utah Code Annotated 1953, as amended, and as a political subdivision of the State of Utah. Under the organizational agreements with its members, UAMPS provides planning, financing, development, |

| Party | Role |
|---|---|
| | acquisition, construction, operation, and maintenance of power generation and transmission projects. UAMPS is primarily a project-based organization, and, as such, members participate in specific projects at their discretion. UAMPS can be considered the Project Sponsor and Project Owner for most of the projects it undertakes. |
| UAMPS Members | UAMPS has 45 members, including public power utilities in eight states. UAMPS members (such as Los Alamos County, NM, Idaho Falls, ID, and others) may elect to buy and distribute power from the SMR. |
| NuScale and Flour | NuScale is the operating company developing the NuScale SMR. NuScale is owned by a number of companies with strategic interests in developing and deploying the NuScale SMR, principal among which is the Fluor Corporation ("Fluor"). Fluor delivers integrated engineering, procurement, fabrication, construction, maintenance, and project management solutions to government and private sector clients in diverse industries around the world. A consortium of Fluor and NuScale will be the developer of the Idaho SMR Project. |
| DOE | DOE owns the property at INL in which the SMR for the Idaho SMR Project will be sited. Additionally, DOE is exploring being a purchaser of power from the SMR (either directly from a UAMPS Member or through WAPA). |
| WAPA | WAPA may be a purchaser of power from the SMR (on behalf of another federal agency). |
| Investors | Provide financing for the construction of the Idaho SMR Project. |

### 6.1.2 NuScale's Small Modular Reactor

NuScale SMRs are housed inside high-strength steel containment vessels and submerged in a large steel-lined pool or water below ground level in the reactor building. The reactor building is designed to withstand earthquakes, tsunamis, tornadoes, hurricane force winds, and aircraft impact. The fuel pool and control room are also housed below ground level.

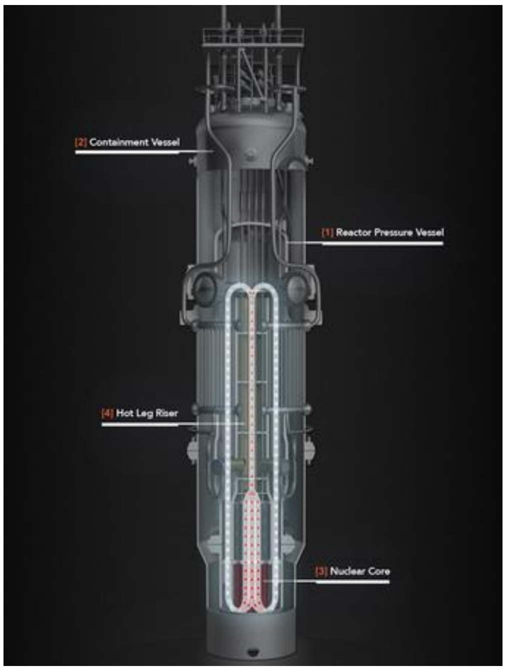
**Figure 17**

**NuScale SMR Model**

© 2013 NuScale Power, LLC

As part of the Idaho SMR Project, UAMPS intends to build a 570 MWe (net) nuclear power plant using NuScale designs. The NuScale Power Module ("NPM") is a 50 MWe integral pressurized water reactor inside a high-pressure steel containment. The Idaho SMR Project would group together 12 NPMs for a single power plant at 570 MWe.[88] The facility is expected to be built in Butte County, Idaho at the INL.

The NPM uses many of the same materials, fuels, and safety systems as existing Light Water Reactors ("LWR"), but incorporates these reactor components inside a single, integral containment vessel.[89] NPMs rely upon natural circulation for normal operation and passive safety systems for decay heat removal for unusual events, such as happened at Fukushima.

| NPM Reactor Diagram[90] | NPM Details |
|---|---|
|  | • Thermal Capacity: 160 MW thermal<br>• Electrical capacity: 50 MWe (gross)<br>• Capacity factor: > 95 percent<br>• Reactor dimensions: 65 feet tall x 9 feet in diameter<br>• Containment dimensions: 76 feet tall x 15 feet in diameter<br>• Weight: 700 tons as shipped from fabrication site<br>• Transportation: Barge, truck, or train<br>• Cost: < $5,100/kilowatt ("KW") due to modular designs, and streamlined construction process<br>• Fuel type: Standard LWR fuel, enriched < 4.95 percent<br>• Fuel configuration: 2 meter-long assemblies set in 17 x 17 configuration<br>• Refueling cycle: 24-month |

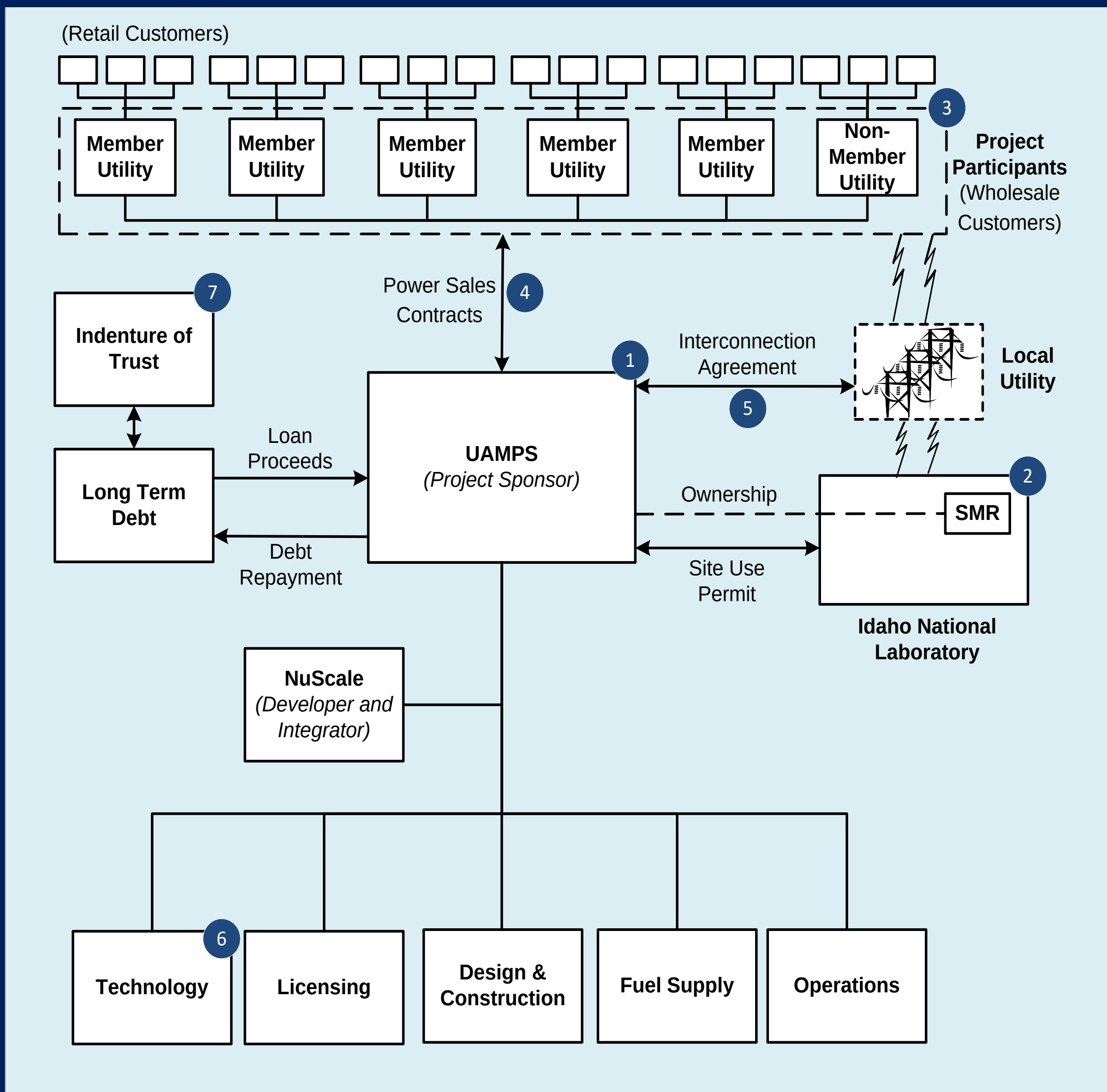
## 6.2 Potential Financial Structure

The Idaho SMR Project is expected to be financed using long-term debt issued by UAMPS and repaid from the Idaho SMR Project's revenues. The Idaho SMR Project's revenues and overall creditworthiness will be derived from long-term commitments to purchase power by the members of UAMPS that elect to participate in the Project. This credit structure supports a financing consisting of 100% long-term debt, thereby lowering the cost of delivered energy to UAMPS' members. This Section presents an overview of the financing structure contemplated for the Idaho SMR Project and the key challenges the Idaho SMR Project may face in shaping a financing structure that meets the requirements of the financial community.

Figure 18 illustrates the financing structure as currently contemplated. As indicated by Figure 18, numerous agreements and commitments must be in place for the Idaho SMR Project to secure debt financing. These commitments, annotated with the numbers 1 through 7 in Figure 18, are described in detail below.

**Figure 18**

**Potential Financing Structure for the Idaho SMR Project**




1. **UAMPS**: UAMPS will be the Sponsor for the Idaho SMR Project.

2. **Site Use Permit**: On February 17, 2016, DOE granted UAMPS a permit (the "Site Use Permit") for a term of ninety-nine (99) years from the commercial operation date for the first nuclear power module of the Idaho SMR Project, which is expected to be within 10 years of the Effective Date. The Site Use Permit identifies that "DOE, under the authority of Section 161g and to further the purposes of Section 3.d of the Atomic Energy Act of 1954, as amended (42 U.S.C. § 2011 et seq.), 42 U.S.C. § 7278, and other applicable law, finds that the permitted

use of the property shall be advantageous to the Government interest. DOE also finds that the potential siting and operation of the CFPP on the INL site shall further the goals of, and should not conflict with, DOE missions at the INL site." The Site Use Permit identifies various phases, activities, and requirements applicable to the development of the SMR at INL.[91]

3. **Project Participants**: The output of the Idaho SMR Project is planned to be sold to participating members of UAMPS or to non-members (the "Project Participants"). The Project Participants consist of municipal utilities and potential other utilities in several western states.

4. **Power Sales Contracts**: The Project Participants' commitment to purchase power from the Idaho SMR Project will be established under Power Sales Contracts between UAMPS and each Project Participant. Under the Power Sales Contracts, each Project Participant will agree to purchase from UAMPS the electric energy allocable to each participant's share of the output of the Idaho SMR Project ("Entitlement Share"). The Power Sales Contracts call for each Project Participant to pay its share of operations and maintenance costs and debt service on a "take or pay" basis. Thus, the Project Participants will pay for the Entitlement Shares of output even if it is not delivered. Importantly, the Power Sales Contracts convey all performance risk associated with the Idaho SMR Project to the Project Participants; payments must be made whether or not the Idaho SMR Project, or any portion thereof, is acquired, completed, or operating. This obligation is not subject to any reduction by offset, counterclaim, or otherwise and is in no way conditioned upon the performance of UAMPS under each Power Sales Contract.

   The obligations of each Project Participant represent a firm commitment that must be paid regardless of Idaho SMR Project performance. Thus, lenders look to the financial health of the Project Participants as the ultimate source (and credit support) of debt repayment. This credit strength is further supported by the obligation of each Project Participant to step up its Entitlement Share by up to 25% in the event of a default by another Project Participant.

5. **Large Generator Interconnection Agreement ("LGIA")**: UAMPS will enter a LGIA with the local utility to allow the facility to interconnect with the grid and export power.

6. **NuScale**: NuScale will integrate the roles of the technology supply, engineering, construction, and fuel supply contractor. These roles will be undertaken under subcontract agreements, the most important of which will be the EPC Agreement. Under the EPC Agreement, the contractor will commit to design and build the Idaho SMR Project on time, within budget, and to expected performance standards. The specific risk allocation is not known at this time, but it is important to note that the risk absorbed under the EPC Agreement represents an important credit feature of the Idaho SMR Project and serves to mitigate the risks assumed by the Project Participants.

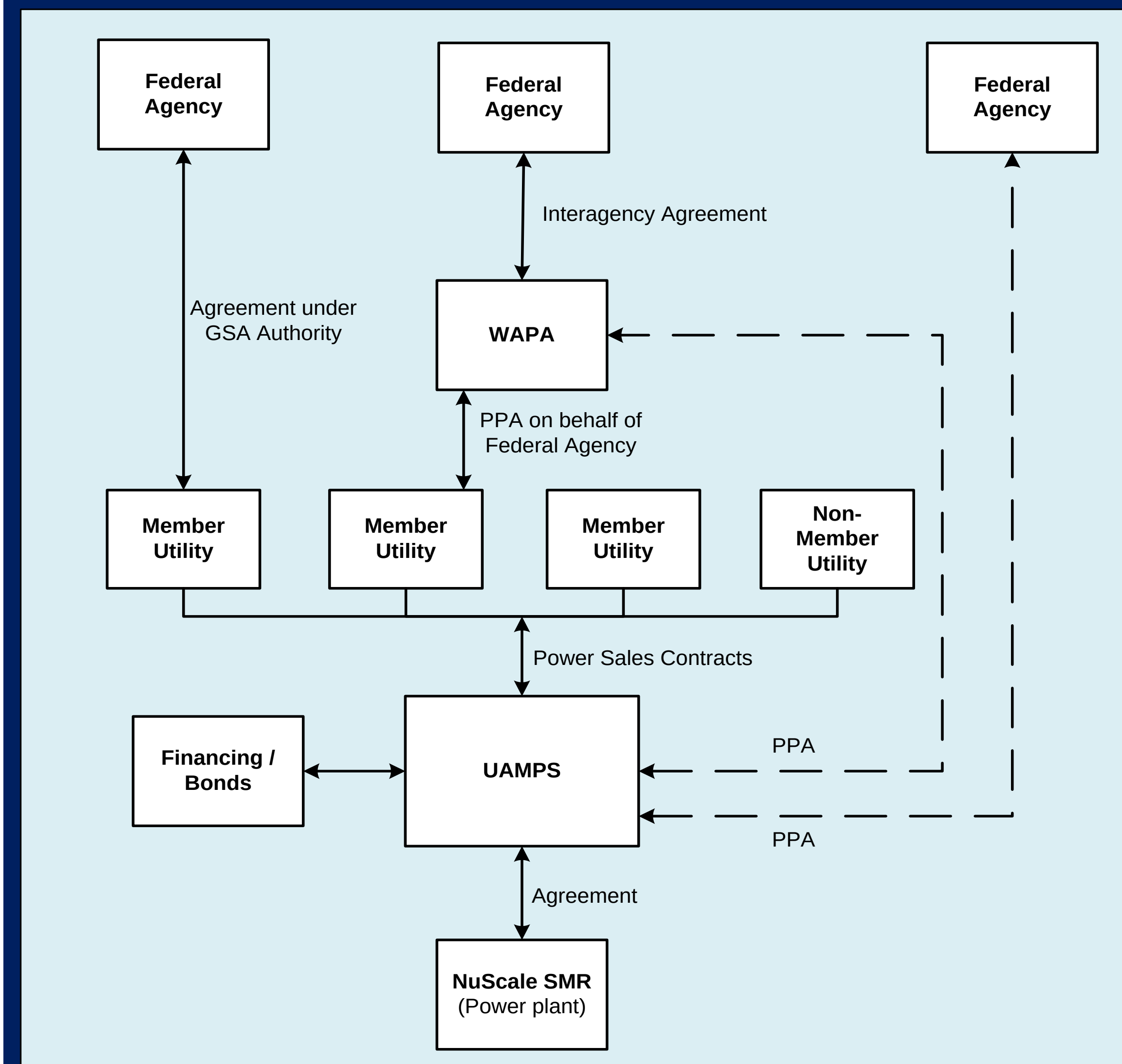
7. **Indenture of Trust**: Pursuant to the Indenture of Trust ("Indenture"), UAMPS will pledge as security for the Idaho SMR Project debt the revenues derived from the Power Sales Contracts and other revenues and income from the Idaho SMR Project. The debt proceeds will be considered special obligations of UAMPS, and, as such, will not be an obligation of the State of Utah, nor will the debt be an obligation or liability of the Project Participants.

### 6.3 Overview of Idaho SMR Project Off-Take Structure

Figure 19 shows an overview of the Idaho SMR Project off-take structure, which is expanded upon throughout this Chapter.

**Figure 19**

**Potential Off-Take Structure for the Idaho SMR Project**




### 6.4 Potential Legal Agreements Involved in a Federal Agency Purchase of Power from an SMR

As depicted in Figure 19, there are several different scenarios through which a federal agency could contract to purchase power produced by the SMR in the Idaho SMR Project. These scenarios are as follows:

*Most Likely Options Contracting Between a Federal Agency and a Utility:*

1. **Option 1: Federal Agency Uses GSA Authority to Contract with a Utility.** Either directly (if DOD or DOE), through GSA, or with delegated authority obtained from GSA, a federal agency can enter into a direct agreement with a utility (either a member of UAMPS or a non-member purchasing power produced by the SMR from UAMPS) to purchase power produced by the SMR for a maximum of ten (10) years. This is likely the most typical method of contracting that will be used by federal agencies, but utilities will likely prefer longer-term agreements outlined below.

2. **Option 2: Federal Agency Collaborates with WAPA to Enter into a Longer-Term PPA with a Utility.** For those federal agencies located within WAPA's service territory, the federal agency and WAPA could enter into an Interagency Agreement. Pursuant to the Interagency Agreement, the federal agency would pay a negotiated charge to WAPA for WAPA to develop a PPA with the utility (either a member of UAMPS or a non-member purchasing power produced by the SMR from UAMPS) on behalf of the federal agency. The Interagency Agreement would identify that the federal agency is responsible for all costs charged under the PPA, as well as a negotiated annual charge for contract administration. WAPA would also enter into a PPA with the utility with a maximum term of 40 years. For federal agencies located in other PMA jurisdictions, this option can be explored.

*Additional Options Contracting Between a Federal Agency and UAMPS:*

3. **Option 3: Federal Agency Uses GSA Authority to Contract with UAMPS.** Either directly (if DOD or DOE), through GSA, or with delegated authority obtained from GSA, a federal agency can enter into a direct agreement with UAMPS to purchase power produced by the SMR for a maximum of ten (10) years.

4. **Option 4: Federal Agency Collaborates with WAPA to Enter into a Longer-Term PPA with UAMPS.** For those federal agencies located within WAPA's service territory, the federal agency and WAPA could enter into an Interagency Agreement. Pursuant to the Interagency Agreement, the federal agency would pay a negotiated charge to WAPA for WAPA to develop a PPA with UAMPS on behalf of the federal agency. The Interagency Agreement would identify that the federal agency is responsible for all costs charged under the PPA, as well as a negotiated annual charge for contract administration. WAPA would also enter into a PPA with UAMPS with a maximum term of 40 years. For federal agencies located in other PMA jurisdictions, this option can be explored.

### 6.5 Financial Impact Analysis of a Federal Agency

This Section presents a notional financial impact analysis of a federal agency considering the procurement of electricity from an SMR via a PPA. The objective of this, or any, financial impact analysis is to determine how the PPA will affect the total power cost of an off-taker relative to existing conditions. Unlike comparing the levelized cost of electricity of alternative generation sources, a financial impact analysis examines the cash flow impact of alternatives on a facility's total electricity bill over a given time horizon and seeks to quantify the added or avoided cost of a new generation source relative to the status quo. For federal agencies, this analysis is an input to the budget planning process. Utility costs are generally funded through annual appropriations, making energy cost forecasts an important consideration.

This analysis considers a PPA consisting of an 8 MW share of the SMR's output, equating to 68,768 MWh per year in generation. Financial impact analysis aims to understand how entering into the PPA will affect the purchaser of power relative to the status quo purchasing arrangement with the local utility.

Conducting financial impact analysis requires a series of simplifying assumptions about how electricity rates may change over time. Some of the key assumptions are summarized here:

- **Bilateral, Firm Power Purchase:** It is assumed that the PPA is signed between the off-taker and SMR owner for firm baseload power. The fixed PPA rate reflects both variable supply and fixed capacity costs; therefore, this analysis accounts for a change in both energy and demand charges from the utility as the SMR electricity substitutes utility power purchases. A failure to deliver under the PPA would result in the utility having to supply power. Therefore, depending on the requirements of the load serving utility, it may impose fixed standby charges.

- **Demand Charges:** It is assumed demand charges will be reduced by the effects of the new generation scenarios on average peak demand for utility power. The specifics for determining changes to demand charges would be found in the tariff of the load serving utility and should be considered in a site-specific analysis. Using the percentage change is a simplification to approximate the result; this location-specific consideration will ultimately reflect the nature of the arrangements among the off-taker, the load-serving utility, and the SMR power producer.

- **Transmission Charges:** It is assumed transmission charges will be the same under the status quo and the new generation scenarios. Transmission charges will need to be factored into off-takers' analyses based on the location-specific considerations.

- **Continuation of Status Quo Costs:** It is assumed that the composition of historical costs not associated with the SMR resemble those in the future.[92]

- **COD/Initial Year in 2025:** This analysis assumes the SMR would be first available for operations following ten years of construction. Status quo costs were escalated between the historical baseline year (2015) and commercial operations (2025).

- **Continuation of Load Profile:** One year of historical usage and billing data was used to establish a baseline for the off-taker's usage and demand.[93] The load profile is assumed to remain the same.

- **Escalation of Non-PPA Rates:** The EIA outlook for future energy costs is used to determine a single compound annual growth rate ("CAGR") in electricity costs that would not be fixed by the PPA.

- **PPA Initial Year Rate:** The PPA Rate is assumed to be \$74.40/MWh.[94]

- **PPA Escalation Rate:** The PPA Escalation Rate would presumably be fixed contractually. A fixed 1% annual rate is used in this analysis based on the PPA pro forma modeling.

- **Discount Rate:** The annual costs of electricity under the status quo scenario and the post-project scenarios are discounted back to the first year at the U.S. Government's discount rate that aligns with the project timeline. In this case, the thirty-year nominal discount rate is 2.8%.[95]

- **Sensitivities:** EIA presents price outlooks across seven different economic scenarios. In this avoided cost analysis, the highest and lowest resulting CAGRs for non-PPA rates were used to present the outcome as a range.

Most of the foregoing assumptions are installation-specific and will vary based on location, load profile, market regulation, and tariff structure. Therefore, in developing a financial impact analysis, it is important to develop inputs that reflect site-specific factors as well as changes that may occur in the future.

As a first step in the financial impact analysis, the status quo cost of electricity was estimated. Based on a review of billing and usage data from a 12-month period, the status quo unit rate for electricity was estimated at $69.80/MWh (for energy, demand, and transmission components), and the annualized status quo energy unit cost was calculated at $34.60/MWh (in 2015 dollars). After applying EIA escalation rates, this energy unit cost was estimated to be between $42.44 and $49.17 per MWh in 2025, the assumed COD year.

The unit of cost energy from an SMR as purchased through a PPA was estimated at $74.40/MWh. The PPA rate and the status quo energy costs (in 2025 dollars) were blended to estimate an initial year unit cost of energy between $47.61 and $53.25 per MWh. This assumes that under the PPA, the buyer's needs in excess of demand met through the PPA would be met through the status quo arrangement. The actual cost of demand is reduced by the percentage reduction in average peak demand and then converted to a cost per MWh consumed. The unit cost of transmission, assumed to be unchanged, but escalated, is then added to the blended energy rate and residual demand rate, resulting in a blended cost of electricity under the PPA between $85.36 and $96.99 per MWh.

The following table summarizes the escalated values in 2025 and compares them to the baseline costs in 2015.

| Comparison of Estimated Unit Costs in 2015 and 2025 | | | |
|---|---|---|---|
| **Assumed COD Year** | 2015 | 2025 | 2025 |
| **EIA Escalation Rate** | N/A | 2.06% | 3.58% |
| | | | |
| **Unit Cost of Energy** | $/MWh | $/MWh | $/MWh |
| Status Quo Cost of Energy | $34.60 | $42.44 | $49.17 |
| Post-SMR Blended Energy Unit Cost | $41.04 | $47.61 | $53.25 |
| **Unit Cost of Demand** | $/MWh | $/MWh | $/MWh |
| Status Quo Cost of Demand | $31.88 | $39.11 | $45.31 |
| Post-SMR Blended Demand Unit Cost | $27.46 | $33.69 | $39.03 |
| **Unit Cost of Electricity (Bundled)** | $/MWh | $/MWh | $/MWh |
| Status Quo Bundled Unit Cost of Electricity | $69.80 | $85.61 | $99.19 |
| Post-SMR Bundled Cost of Electricity | $71.81 | $85.36 | $96.99 |
| **First Year Cost of Electricity (Nominal)** | $ | $ | $ |
| Status Quo Bundled Cost of Electricity | $29,638,790 | $36,354,772 | $42,118,309 |
| Post-SMR Annual Bundled Cost | | $36,247,446 | $41,183,902 |
| (Additional Cost) | | $107,326 | $934,407 |

Having established the cost of electricity under the PPA, the total cost of electricity in the first year of the PPA was estimated at between $36.2 million and $41.1 million. This is between $0.1 million and $0.9 million less than estimated status quo electricity costs in 2025, depending on the effective escalation rate. The same escalation rates were then used to forecast future costs in the status quo and PPA scenarios over forty years.

Based on the escalation scenario used, in present value terms, as summarized in the below chart, the cost of power under the PPA over forty years was estimated at between $25.9 million and $101.0 million less than under the status quo arrangement. While this estimate is subject to significant uncertainty given the rapid evolution in energy markets, it provides an indication of the potential cost impacts of a PPA for SMR-generated power. Financial impact analysis is one tool to assist decision-makers in considering power purchase arrangements and should be weighed alongside other considerations, such as policy objectives, limiting market risk exposure, and economics.

| Summary of Avoided Cost Findings | | |
|---|---|---|
| **Scenario** | **EIA Low** | **EIA High** |
| **EIA Escalation Rate** | 2.06% | 3.58% |
| | | |
| **Nominal Cost - 40 years** | | |
| Status Quo Cost of Electricity | $2,226,341,966 | $3,624,762,425 |
| Post-SMR Cost of Electricity | $2,156,649,841 | $3,354,393,551 |
| Avoided or (Additional) Cost | $69,692,125 | $270,368,874 |
| | | |
| **Net Present Value (in 2015 dollars)** | | |
| Avoided or (Additional) Cost | $25,904,989 | $101,036,675 |

*Alternative Scenario – Off-Site Purchases of SMR Energy via Utility Partnership*

In this notional analysis, the generation from the SMR was assumed to be purchased directly from the project owner; however, a federal off-taker may also consider how it can elect to receive energy from a specific source in partnership with its local electric utility. In this scenario, the cost comparison would be in the hands of the utility, and the exercise would be one in which the cost of energy from the SMR would be compared against the utility's marginal cost of wholesale power.

For this alternative scenario, the analysis can be simplified to a comparison of expected annual costs under the PPA rate and the marginal cost of wholesale power supply. For example, the SMR energy would come at a premium in the first year if the marginal cost of power supply was below $74.40/MWh. However, over the forty year term of the PPA, the low escalation rate would narrow the difference as fuel and operating costs for conventional generation options escalate higher than the PPA escalation rate (1%). Demand charges would remain the same, as procuring off-site energy would not reduce the off-taker's monthly peak demand for utility power.

A more comprehensive analysis of this alternative scenario would have to be market specific and requires knowledge of a utility's marginal cost of wholesale power and their regulatory environment for energy (i.e., competitive or fully regulated). The analysis should address the following three issues in its final recommendation:

1. If the off-taker initiates the decision to purchase SMR energy through the utility, the utility would have to decide how SMR energy costs would be passed through without socializing these across its entire rate base. This could come in the form of a special tariff, in the same style as "green tariffs" that allow off-takers to elect to buy renewable power being procured by the utility.

2. The comparison should take into account decisions by the utility about its generation mix that could alter their blended wholesale cost. This could include

weighing price certainty against cost when comparing the contracted price for utility owned generation against short-term purchases of power.

3. Comparing options that would be effective several years from now requires forecasting and a view on escalating market prices. This level of study goes beyond using EIA for price outlooks and notional growth rates and would need to develop a market specific range of possible costs. However, it is reasonable to assume that the utility, having determined the need for a new source of baseload power, could simply compare the LCOE of alternative sources against that of an SMR and then look to tariff options for allocating the cost and benefits of the SMR power.

Please see Appendix D for more details regarding this notional financial analysis.

## 6.6 Key Financing Issues to Address

As contemplated, the financing structure of the Idaho SMR Project provides strong credit fundamentals and should facilitate the development and financing of the Idaho SMR Project at a long-term fixed interest rate. Importantly, this structure should improve the competitiveness of the Idaho SMR Project relative to other sources of baseload power. However, a number of challenges are introduced by this first of a kind project:

- **Licensing Risk:** Early in the Idaho SMR Project development process, the Idaho SMR Project will need to obtain a COL from the NRC. In order to receive a COL, the Idaho SMR Project will have to invest millions of dollars in early stage development cost. Under the plan, these expenditures will not commence until the Power Sales Contracts have been executed. Therefore, the risk from the COLA process will fall upon the participating members of UAMPS. Failure to receive a COLA will result in financial losses for UAMPS, and such losses will be incurred prior to plant construction. There is also uncertainty of completion, because the NRC will need to provide approvals before the facility can begin operations. At this stage, the Idaho SMR Project could experience delays in production, adding expense to UAMPS and its subscribers.

- **Technology Risk:** If implemented, the Idaho SMR Project will be the first SMR sited and constructed in the United States. The technology risk associated with this first-of-a-kind project represents a key challenge for the project sponsor to overcome. Idaho SMR Project lenders will need to become comfortable with the Idaho SMR Project's engineering and construction plans, as well as plans for long-term operations. In addition, the licensing risk introduced by an untested regulatory process could introduce delays in the initiation of commercial operations. These considerations will need to be addressed in the Idaho SMR Project's financing plan to ensure adequate protection to Idaho SMR Project lenders.

- **FOAK Costs:** A key benefit of SMRs is that component parts and assemblies could be manufactured in a factory and shipped to the Idaho SMR Project site. Over time, this could introduce significant economies of scale into the plant construction process. However, the Idaho SMR Project will not benefit from these economies as it is the first SMR to be built, and thus faces FOAK costs, which are higher than would be expected over the long run as costs decrease.[96]

- **Uncertainty in Long-Term Energy Markets:** While it is widely recognized that the aging fleet of coal fired power projects and nuclear generating stations will need to be replaced over the next decade, the current conditions in the energy markets have introduced long-term uncertainties. In particular, the current low-cost of natural gas makes it challenging for other sources of baseload power to be competitive on price alone. While the historic volatility of natural gas is well recognized, the abundant supply of natural gas and its current cost profile make it the most economic option at this time. There is considerable uncertainty over the changes in demand for natural gas and the market equilibrium that will be achieved over the long-term.

- **Development Timeline:** Given the need to find replacement sources of baseload power, the uncertainty over the Idaho SMR Project's development timeline may introduce challenges to Project Participants. Specifically, Project Participants require a new source of baseload power to be commissioned by 2025, and thus require a precise estimate of the expected commercial operation date of the Idaho SMR Project. Since the Idaho SMR Project is subject to considerable uncertainly in respect to licensing, financing, and construction, this presents a challenge for all involved.

- **Production Tax Credits:** According to the Project Sponsor, the production tax credits that were introduced in EPACT are essential to making the Idaho SMR Project cost-competitive. However, for the Idaho SMR Project to benefit from the tax credits, the sunset date on the production task credits must be extended, and the Idaho SMR Project will need to be structured such that it can benefit financially from the tax credits. To do so, the Project Sponsor will need to allow private ownership of the plant or the amended legislation will need to allow the tax credits to benefit public power producers. Under either scenario, the Idaho SMR Project will require legislative actions.

- **DOE Loan Guarantee:** According to the Project Sponsor, the Idaho SMR Project may seek a DOE loan guarantee for part or all of the Idaho SMR Project financing. Given the new technology risk identified above, the DOE Title XVII Loan Guarantee Program represents an attractive and well-suited source of financing for the Idaho SMR Project. However, by statute, the DOE loan guarantee cannot benefit directly or indirectly from support provided by federal off-takers.[97] Therefore, the purchase of power from the Idaho SMR Project by a federal agency, such as a DOE laboratory, could impair the Idaho SMR Project's ability to obtain a DOE loan guarantee or limit the amount of the loan guarantee. This issue represents an important consideration in designing the Idaho SMR Project's financial structure.

## KEY CHAPTER TAKEAWAYS

- The Idaho SMR Project will be owned by UAMPS and financed by debt on the balance sheet of UAMPS. UAMPS will lease land from INL to site the SMR and sell power to UAMPS' participating member utilities. A federal off-taker could then buy power from one of UAMPS' member utilities or UAMPS itself. UAMPS will contract with NuScale for the development of the SMR.

- The Idaho SMR Project's financial structure has a number of strong features which should enable its access to commercial debt financing. In particular, the Idaho SMR Project's credit is supported by commitments of each of the Project Participants. However, key challenges will have to be resolved to achieve the best financial terms. These include uncertainty and high costs related to using a new technology, uncertainty around future prices of power from other baseload technologies, a tight construction schedule, and availability of support from the federal government through tax policy or off-take.

- In order to contract for a term longer than 10 years, a federal agency within WAPA's territory may wish to enter into an Interagency Agreement with WAPA, who in turn will enter into a PPA with UAMPS or a UAMPS' member for up to 40 years on behalf of a federal agency. The federal agency and WAPA would also enter into an Interagency Agreement providing that the federal agency would make all payments due under the PPA.

- Federal off-takers could also enter into PPAs with UAMPS or UAMPS' member utilities under the GSA authority for up to 10 years; however, such PPAs would not be for the duration of the financing.

- Power from an SMR may be more expensive than the power an agency is currently purchasing. However, this cost may be worthwhile to support a new technology whose costs are expected to fall over time as production efficiencies are realized, offers energy security, or a range of other potential benefits.

- Legislative changes will be required for the Idaho SMR Project to benefit from PTCs; the sunset date for PTCs will have to be extended. Also, UAMPS will have to allow for private ownership of the Idaho SMR Project or legislation will have to be amended to allow PTCs to benefit publicly-owned projects.

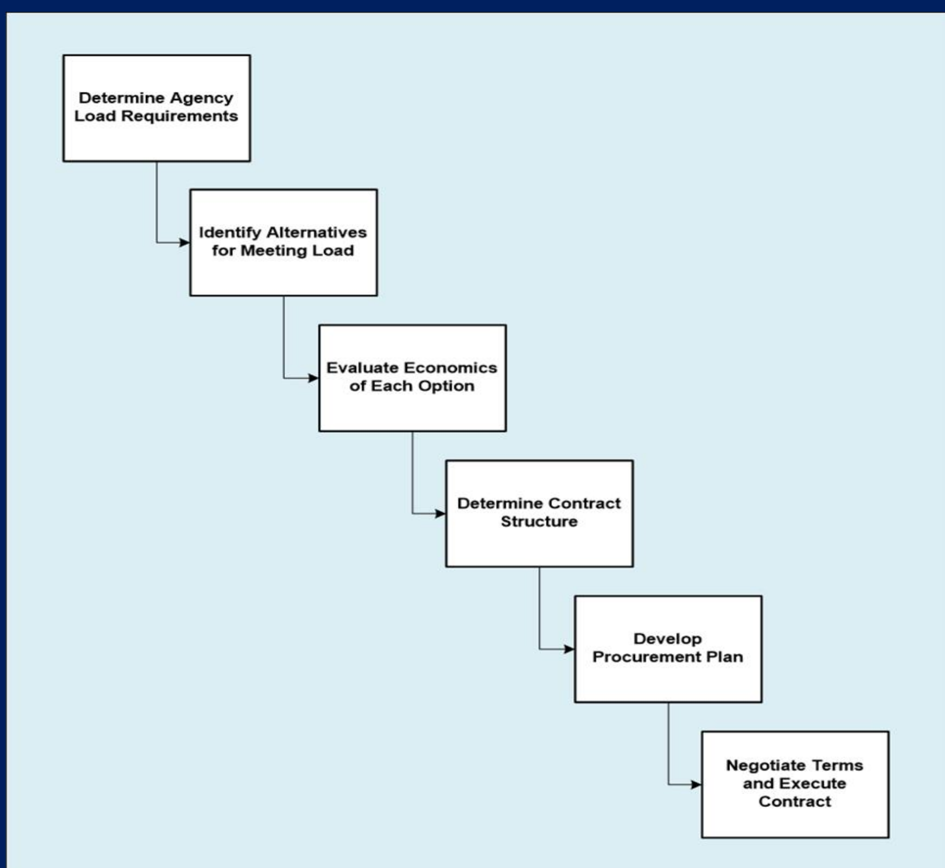
- By law, projects that have a loan guarantee from DOE's Title XVII Loan Guarantee Program cannot have support in the form of federal off-take.

# CHAPTER 7: ROADMAP FOR FEDERAL AGENCIES INTERESTED IN PROCURING POWER FROM SMALL MODULAR REACTORS

As detailed in the preceding Chapters of this Report, federal agencies have significant purchasing power that can provide meaningful support to advancing commercial deployment of SMRs. The delivery of reliable electric power is essential to the on-going operations of federal facilities and directing these expenditures to achieve a policy goal represents an efficient use of government financial resources. Despite the compelling rationale for utilizing federal PPAs, federal facilities face a complex and challenging process for entering into such transactions. These requirements relate to energy planning, economic analysis, legal structuring, procurement processes, and negotiation of terms and conditions, as depicted in Figure 20 and described below.

**Figure 20**

**Roadmap For Federal Agencies Interested in Procuring Power from SMRs**



Once the policy objective has been established to support commercial deployment of SMRs through the utilization of federal PPAs, a federal agency will need to shape the acquisition strategy to address a number of factors. As illustrated above, this process can be summarized in six major steps, as described below.

1. **Determine Long-Term Load Requirements:** Based on the mission of the federal agency, its existing load profile, current sources of power supply, and expectations related to changes in the future, the federal agency will need to determine its load requirements over the period of the potential PPA term. This represents a long-term planning exercise akin to an integrated resource plan developed by a utility and should result in the quantification of loads to be served by the SMR. As a source of baseload power, the SMR will serve a portion of the federal agency's total load. The federal agency may also want to consider how the SMR fits into its energy portfolio, including diversity of supply, forward price hedging, and clean energy goals.

2. **Identify Alternatives for Meeting the Projected Load:** In order to perform an economic analysis of the SMR PPA, the federal agency will need to take a view on alternative sources of power that will affect its cost of service over the long-term. The key consideration for the federal agency will be the cost added or avoided by entering into a long-term PPA. This information will likely be required as part of the approval process within the agency or the department, and it is assumed that economics will represent one of several evaluation criteria.

3. **Evaluate Economics of Each Option:** Evaluating the economics of alternative sources of power supply represents a forward-looking analysis of energy loads and sources of supply. Fundamental to this analysis is establishing a base case against which alternatives can be compared. The base case should contemplate the buyer's long-term objectives in terms of different generation sources, exposure to market volatility, and policy objectives / compliance. In addition, an estimate of electric power cost escalation is required for the planning horizon. After establishing the base case, the avoided / added cost associated with an SMR PPA can be determined. These can be enumerated for annual periods and on a net present value basis. To the extent costs are increased, these increases should be weighed against the public policy objectives being pursued.

4. **Determine Contract Structure:** The terms and conditions of the PPA will be influenced directly by the legal authority under which the acquisition is pursued and executed. Accordingly, the federal agency must identify how it can legally enter into a long-term contract with the SMR counterparty to deliver energy over the desired term. As noted previously, a number of legal authorities exist today and careful structuring is required to ensure the utilization of such authorities does not result in negative budget scoring treatment. While there are numerous precedent transactions in the federal sector for long-term energy purchases, each situation is unique and entails careful legal structuring to address the needs of each counterparty and achieve the desired budgetary and economic outcome. Additionally, the federal agency must review applicable state

laws to confirm the proposed transaction is in accordance with the applicable state laws governing the provision of electric utility service.

5. **Develop Procurement Plan:** Depending on the specific circumstances of the federal agency, the procurement of power may involve a competitive solicitation or direct coordination with the local load-serving utility. Therefore, the federal facility will need to identify alternatives for procurement and develop a plan for selecting a provider of electricity produced by the SMR.

6. **Negotiate Terms and Execute Contract:** Depending on whether the contract vehicle for the PPA is a FAR-based contract, under the authorities of a PMA or TVA, or a standard commercial contract, the terms and conditions will be very different. The federal agency will need to negotiate terms to meet its specific requirements, and the contract terms will need to achieve a balanced risk profile such that the contract can support the project's financing needs.

Each of the steps outlined above involves significant technical, financial, and legal resources. While the process will be similar for each federal agency, achieving economies and standardization in this approach represents a challenge. However, the process could be streamlined with the development of policies and legislative changes targeted at advancing the commercial deployment of SMRs and tailored to supporting longer term power purchase arrangements.

In order to overcome some of the obstacles described above and better support the financing of an SMR project with federal customers, legislative changes could include the following:

| Potential Legislative Changes to Better Support an SMR Project | |
|---|---|
| **1. Extend GSA Authority for Certain Types of Power Sources** | • Amend 40 U.S.C. § 501 to permit longer contract terms (i.e. 25 – 40 years) for nuclear or other types of energy that require more regulatory approvals or expensive financing than other power sources |
| **2. Extend DOD's 10 U.S.C. § 2922a** | • Amend 10 U.S.C. § 2922a to apply to a broader federal audience than only DOD<br>• Apply 10 U.S.C. § 2922a to nuclear and other types of carbon-free energy that require more expensive financing that other power sources |
| **3. Create a new legal Authority** | • Similar to amending 40 U.S.C. § 501, create a new legal authority that permits federal agencies to purchase SMR produced power for a term of 30 years |

Additionally, the Department of Energy's January 2017 Quadrennial Energy Review identifies the following recommendations that would assist with the development and purchasing of power from SMRs:

- **“Extend the time frame and the total capacity allowed under the PTC for nuclear generation.** Current law provides a \$0.018/kilowatt-hour production tax credit for new nuclear plants placed in service by 2020 and places a capacity cap of 6,000 MW. Extend the eligibility date so that reactors placed in service after 2020 could qualify and increase the capacity cap.

- **Increase power purchasing authorities for the federal government from 10 to 20 years.** The federal government is currently subject to goals and mandates for the purchase of clean energy which, if achieved, can help to catalyze action in the private, state, and local sectors. However, widespread federal government clean energy purchases are constrained by generally applicable procurement rules that prohibit entering long-term contracts. Congress should authorize all federal agencies to negotiate 20-year power purchasing authorities for clean energy.”[98]

# APPENDIX A
# POTENTIAL BENEFITS OFFERED BY SMALL MODULAR REACTORS

| Potential Benefits Offered by SMRs | |
|---|---|
| **Carbon-Free Baseload Power** | • SMRs provide carbon-free baseload power. |
| **Enhanced Safety** | • SMRs may be safer than conventional reactors since they will be built below ground, and thus could be better protected from human and natural risks.<br>• Passive safety systems allow for improved accident avoidance and tolerance.[99, 100]<br>• Transportation of fuel may be minimized since the reactors can be fueled when manufactured in a factory.<br>• The small size of SMRs means that they have a smaller radioactive inventory than larger nuclear plants. Uranium requirements for making fuel for traditional plants are 53% higher than for SMRs, with a respective difference in spent fuel volume.[101]<br>• Containment of fuel during all stages of the fuel cycle could be carefully monitored. SMRs would be fabricated and fueled in a factory, sealed, and transported to sites for power generation, and then returned to the factory for controlled defueling. This model could help mitigate risk involved in transporting and handling nuclear material and assist in the quick decommissioning of plants and remediation of sites.[102] |
| **Modularity** | • As major components can be manufactured off-site and shipped to the point of use, SMRs allow for the separation of constructor and operator roles and the centralization of manufacturing expertise.[103]<br>• Limited on-site construction is required.<br>• Individual factories could fabricate components for multiple SMRs, increasing fleet-wide design consistency and standardization. By manufacturing multiple reactors of smaller size at centralized facilities, manufacturers are likely to experience rapid learning curves, which should transfer to a more robust understanding of the technology.[104]<br>• Modularity and standardized designs can also increase the safety and efficiency of plant operations, as they eliminate idiosyncratic design features between plants and streamline operating and maintenance procedures.[105] |

| Potential Benefits Offered by SMRs | |
|---|---|
| **Lower Cost** | • The cost of an SMR has been estimated to be between $800 million and $2 billion per unit, whereas a large reactor typically costs between $10 billion and $12 billion.[106]<br>• The smaller size of SMRs should translate to each reactor being less capital intensive; costs associated with manufacturing and construction are reduced as less material is required. Factory fabrication can mean quicker on-site construction, which reduces the cost of labor and shortens the interval between construction of the reactor and when the reactor begins to generate electricity.[107] |
| **Scalability** | • SMRs have a responsive, adaptable site capacity and can provide power for a range of applications.<br>• In developing countries or rural communities that lack the transmission infrastructure to support a large nuclear plant, SMRs provide a way for utilities to still have baseload power on the grid.[108]<br>• Nuclear plant operators can gradually scale up the number of SMRs at a single plant location as demand grows, distributing cost evenly throughout the lifetime of a nuclear power plant.[109]<br>• Utilities could use SMRs as on-site replacement for aging fossil fuel plants – taking advantage of existing transmission infrastructure.[110] |
| **Improved Energy Security** | • Having an SMR located on-site may provide long-term energy security to the federal agency, rather than relying on a separate grid that is outside the control of the federal agency.<br>• By providing two years of fuel on-site, vulnerabilities relating to fuel transportation disruptions are minimized. |
| **Integration of Renewables** | • NuScale's SMR design allows for output to be varied over days, hours, or seconds. This can allow SMRs to adjust their output in response to changes in electricity output from intermittent renewable generation. |
| **Siting Flexibility** | • The small size of SMRs may allow them to be sited in places where a large baseload plant is not feasible or not needed. For example, SMRs have been considered as a power source for remote mines in Canada which cannot access the grid.[111] |
| **Small Land Requirements** | • SMRs require significant less land than would power plants with the same output which use wind, solar, biomass, or hydropower. NuScale estimates that SMRs require only 1 percent of the land area required for similar generation by other technologies. |
| **Process Heat** | • SMRs heat water in the process of producing electricity. Some SMR designs may be useful for producing process heat for desalination and other industrial activities. |
| **International Export Opportunities** | • United States companies that produce SMRs or sell related goods or services may have opportunities to sell to foreign markets. EIA estimates that global electricity generation will increase by 69 percent from 2012 to 2040.[112] |

| Potential Benefits Offered by SMRs | |
|---|---|
| **Reduced Fuel Risk** | • SMRs can help diversify a generation portfolio and reduce fuel risk. The price of electricity from SMRs, especially under a long-term contract, should be relatively stable and predictable.<br>• Natural gas prices have historically been very volatile, although they have been low in recent years. Higher natural gas prices generally increase the price of electricity produced from natural gas. |

# APPENDIX B
# OVERVIEW OF THE UNITED STATES POWER SECTOR

**Main Segments of the United States Power Sector and Their Ownership**

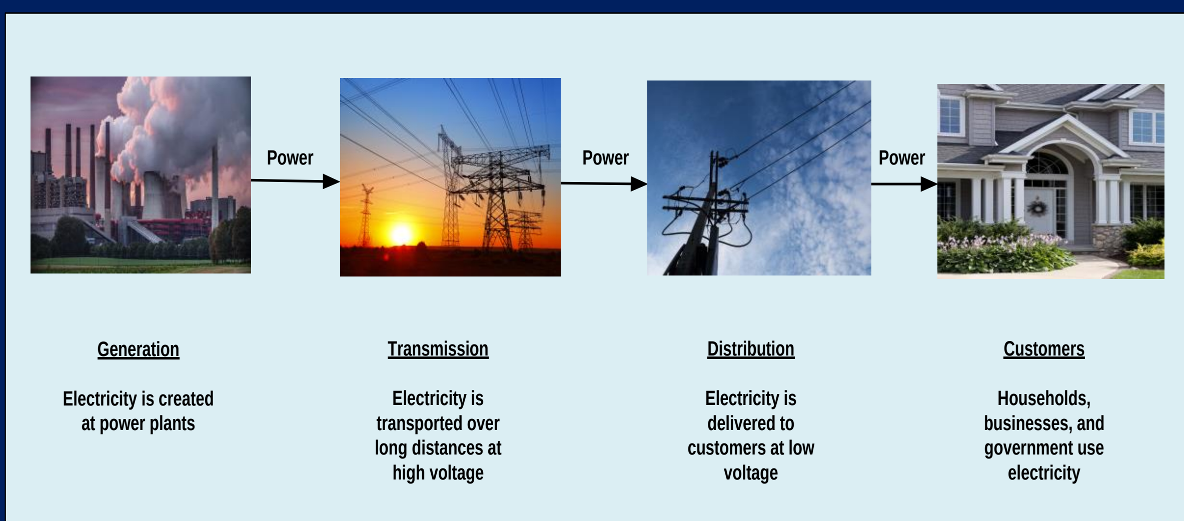
The United States power sector has three main segments which work together to produce power and then bring that power to customers. These segments are:

1. Generation;
2. Transmission; and
3. Distribution.

The three segments, and how they work together to create electricity and transport it to customers, are shown in Figure 21.

**Figure 21**

**Main Segments of the Electricity Sector**




### *Generation*

Generation refers to the creation of electric power through conversion from thermal sources (such as steam or heat) or kinetic sources (such as wind or flowing water). Electricity can also be generated through electro-chemical processes, such as converting solar energy to power. The performance characteristics of different energy sources and generation technologies vary immensely. For example, thermal sources such as steam turbines offer a reliable source of baseload generation, because they can operate 24-hours a day, 7-days a week. In contrast, photovoltaics generate electricity only when the sun is shining and are thus called an intermittent resource (as is wind power). The management of generation resources is a critical function in maintaining the reliability and stability of a power grid. Accordingly, generation assets are dispatched by the grid operator to meet changing load requirements over the course of a day.

#### *Transmission*

Transmission refers to the movement of electricity over long distances through high voltage lines. Transmission is also a wholesale activity. Transmission lines generally transport power from the generation sources to utilities and within and between utilities. In addition, transmission lines are important for balancing supply and demand for power, as they can be used to move power from a region with excess supply to another region with inadequate supply at a given time. Transmission lines can also allow utilities in one area to draw power from cheaper generation sources which are far away. The movement of electricity from one utility's territory to another is called "wheeling."[113] Wheeling occurs, for example, when power is produced in one territory and delivered to a user in a neighboring one or when power is produced in one territory, transported across one or more territories, and then delivered to a user in yet another territory.

#### *Distribution*

Distribution refers to the delivery of electricity to end users over low voltage lines. This involves the conversion of high voltage current to lower voltage current via transformers and the delivery of low voltage current to the end user, often referred to as a retail customer. Thus, distribution has a focus on managing billing and communications with a large group of end users.

### Power Sector Ownership Models

Private and public entities own assets in all segments of the power sector. These entities possess unique characteristics, operating within specific segments or across the entire value chain.

#### *Investor Owned Utilities ("IOUs")*

IOUs are private shareholder-owned companies that own generation, transmission, and distribution systems. IOUs' activities are subject to applicable state and federal regulations.

In 2016, about 68 percent of retail power customers were served by IOUs. In certain parts of the United States, such as the Southeast, it is common for all generation, transmission, and distribution in an area to be owned by one company. Some IOUs are part of holding companies which may own multiple businesses in one or more areas. A number of IOUs also provide retail natural gas services. Examples of IOUs in the United States include PacifiCorp, a utility whose subsidiaries serve many western states, and Southern Company, a utility holding company with regulated subsidiaries serving many southeastern states.

### *Public Utilities and Cooperatives*

Public utilities are usually owned by cities or counties, although some are owned by states. In 2016, 32 percent of retail power customers were served by public utilities (15 percent were served by municipal utilities, 13 percent by cooperatives, and 4 percent by federal entities). Examples of public utilities in the United States include the Los Alamos Department of Public Utilities, owned by the County of Los Alamos, New Mexico, and the Los Angeles Department of Water and Power, owned by the City of Los Angeles.

Like IOUs, public utilities may own generation, transmission, or distribution assets. Many public utilities, including the two mentioned above, also provide services outside of electricity, such as water supply and sewerage. Public utilities are generally regulated by the governments that own them.

Cooperatives are similar to public utilities in that they are not private businesses; they are non-profit organizations which are owned by their customers.

### *Independent Power Producers*

IPPs are privately-owned businesses focused exclusively on power generation. An IPP could own one power plant or a portfolio of plants.[114] IPPs produced about 40 percent of United States power output in 2016. Some IPPs may sell all their output to one buyer (often a utility) through a long-term contract, to multiple buyers through different contracts, or sell power into a competitive market. IPPs must comply with the regulations of the states in which they operate.

Examples of IPPs in the United States include Calpine Corporation, which has power plants in 21 states and is traded on the New York stock exchange, and RPM Access LLC, a small company that owns wind generation projects concentrated in Iowa.

### *Independent Transmission Companies*

An independent transmission company owns transmission lines. Examples of independent transmission companies include ITC Holdings Corporation, which operates in six mid-western states, and Trans-Elect Development Company LLC, which has developed projects around the United States. The operations of transmission companies are regulated by states and by the federal government when they cross state lines.

### *Federal Power Authorities*

The federal government is a significant player in the wholesale power sector in much of the country through four PMAs and the Tennessee Valley Authority (“TVA”). TVA is technically not a PMA, but it carries out similar functions.[115]

The PMAs do not serve the northeastern United States or much of the Midwest and Florida. Additionally, a fifth PMA serving Alaska was divested in 1995 because its goals had been met, and utilities were deemed able to manage the PMA’s projects beneficially.

As their name would imply, PMAs generally do not own generation facilities (with the exception of Bonneville Power Administration ("BPA") which owns a nuclear power plant). PMAs market power from facilities owned by other federal agencies, primarily the Army Corps of Engineers and Bureau of Reclamation. The International Boundary and Water Commission also owns two plants along the Rio Grande on the border with Mexico. Except for Southeastern Power Administration, all PMAs own transmission infrastructure, and all are involved in managing transmission in their territories. In 2012, the PMAs marketed 42 percent of all hydropower output in the United States.

The federal government also owns TVA, which generates power and sells it to commercial and industrial customers, including the United States Army, and to distribution utilities serving nine million people across seven states in the southeastern United States. TVA also owns transmission infrastructure. Outside of electricity, TVA provides flood control, navigation, and land management services, and supports economic development. TVA is a significant generator of power, owning 73 power plants, including three nuclear plants. TVA also operates fossil fuel, hydropower, solar, and wind plants.

**Regulation of the Power Sector**

Regulation of the power sector has changed significantly over time and now varies across the states, with some activities under federal regulation. The state regulatory regimes are a major determinant of the structure of the states' power markets. Some states employ the "traditional" regulatory system in which an integrated utility has a monopoly for all electricity services in a territory and sells at prices approved by a regulator. Other states have been partially or fully deregulated.

The federal government's regulatory role has grown over the years, overseeing transport of power between states and encouraging the use of competitive markets. Federal policy has encouraged other states to pursue deregulation, which turns some segments of the power sector into competitive markets. Competition is most common in generation where competitive markets are managed by independent entities that also ensure open access to transmission. Some states also allow competition in retail sales to end-users.

The following Sections detail the evolution of power sector regulation and its impact on the structure of the power industry.

**Foundations: State Regulation of Private Utilities**

The first utility was developed by Thomas Edison as a privately-financed business in 1882 in Manhattan. This business generated power and distributed it to nearby buildings, thus establishing the basis for integrated utilities to provide generation, transmission, and distribution. Other early utilities were also private enterprises in urban areas.

Regulation of private utilities in the United States started in the late 19th century with franchise licensing by municipalities.[116] This regulation resulted from court decisions that determined that natural monopolies which provided public services could have their rates and service quality regulated by the government. Many utilities had overlapping territories in more densely populated urban areas and would compete for customers.

Georgia, New York, and Wisconsin established the first state utility regulators in 1907, which took over regulatory responsibilities from municipalities. In the next seven years, 27 other states assumed responsibility for regulation of utilities and the remaining states followed soon thereafter. In addition to the 50 states, the District of Columbia, Guam, Puerto Rico, and the Virgin Islands have utility regulators.[117]

Through regulations, the states granted utilities exclusive franchises to generate, transmit, and sell power in specific geographic areas in exchange for meeting price and service quality requirements. These franchises combined wholesale and retail services. Regulation focused on "cost-of-service" pricing in which regulators aimed to set prices that would allow utilities to recover costs and make a profit, while keeping prices reasonable for consumers.

In order to reduce costs and improve technical performance, utilities started forming power pools to share generation and transmission resources. The first of these was the Pennsylvania, New Jersey, and Maryland Pool ("PJM") established in 1927.[118] Power pools are multilateral agreements in which utilities cede control over their generation and transmission to a common operator. Utilities also entered into many bilateral agreements to share resources. Power pools are still active today in some parts of the United States that are not covered by an ISO or RTO, as discussed in Section 5.3.2.

**Increasing Federal Role**

Federal involvement in electricity started to approach its modern form with the establishment of the Federal Power Commission ("FPC") in 1920 to coordinate federal hydropower projects. The Federal Power Act of 1935 turned FPC into a regulator with the mandate to oversee the sale and transport of electricity across state lines.[119] Growing generation capacity encouraged growth and consolidation of utilities to realize economies of scale. A later law gave FPC a regulatory mandate over natural gas.

While there was significant growth in private power companies, they did not expand much into rural areas. The Federal government stepped in to support expansion of the grid into areas that were not economical for private utilities. One of the first major actions in this regard was the establishment of the TVA in 1933, a federally-owned transmission company with a mandate to build lines in underserved areas. This was followed by the establishment of the Rural Electrification Administration ("REA") in 1935 and the passage of the Rural Electrification Act of 1936, which enabled lending by REA. Although REA offered loans to private utilities to expand into rural areas, there was little interest from them. However, rural cooperatives did want loans, and the Electric Cooperative Corporation Act was passed in 1937 to facilitate the creation and operation of not-for-profit cooperative utilities.[120, 121]

Also during the 1930s, the federal government pursued large flood control and irrigation projects, including the construction of large dams owned by the Army Corps of Engineers and the Department of the Interior's ("DOI") Bureau of Reclamation. These dams could also be used to produce power, and the Federal government created PMAs to market power from them.[122] The first PMA, the BPA, was created by Congress in 1937 to market power from dams in the Pacific Northwest.[123] The Southeastern Power Administration was created in 1943, and the Southwestern Power Administration was created in 1950.[124, 125] WAPA was created in 1977 to sell hydropower in response to high gas prices.[126] The PMAs also own and operate transmission lines and produce power to a limited extent.

The federal government's regulatory reach into the states was extended by the 1964 *City of Colton v. SoCal Edison* court case, which established that FPC had jurisdiction over intrastate sales of power that had been previously transported over state lines. In 1977, in response to the electricity brownouts of the 1960s and oil embargo in the 1970s, Congress reorganized the FPC as FERC.

The North American Electric Reliability Council ("NERC") was created in 1968 to help ensure the reliability of the transmission system after the New York blackout of 1965. NERC is a voluntary association of utilities in the United States, Canada, and a small part of northern Mexico. NERC is divided into ten regions, each of which sets its own planning and system operation requirements. NERC is legally empowered to enforce regulatory standards for system reliability in the United States and Canada. In Mexico, the federal electricity regulator has adopted some NERC standards.[127]

**Federally-Driven Deregulation and Competition**

Since the late 1970s, the power sector has moved towards increasingly competitive and integrated markets, especially in wholesale power. The Public Utility Regulatory Policies Act of 1978 ("PURPA") aimed to support investment in cogeneration and small renewable power plants (called Qualifying Facilities or "QFs"). This stimulated the market for development of privately-financed generation facilities owned by IPPs which are not part of integrated utilities.[128]

In 1988, FERC allowed the states to open the IPP market to projects that were not QFs. This meant that any generation technology could be used by an IPP. FERC also allowed state utility regulators to let electricity rates be set based on competitive bids from IPPs to supply specified amounts of generation capacity.

The extent to which states encouraged growth of IPPs varied. Some states, such as Connecticut and New Hampshire, ordered utilities to divest generation assets through legislation or regulatory orders. In other states, such as Pennsylvania, Maryland, and New Jersey, utilities divested their generation assets without an explicit mandate, although legal and regulatory incentives may have encouraged them to do so. In other regions, such as much of the Southeast, as of 2010, IPPs were still relatively rare.[129]

Transmission grids were opened up to unrestricted access by the Energy Policy Act of 1992, which allowed FERC to grant access to transmission lines upon request. FERC then enacted Order No. 888, which mandated open transmission access to all transmission lines and extended open access to municipal, cooperative, and federal utilities. This facilitated competition in generation by allowing power to flow more freely across the grid, effectively connecting a wider range of generators and utilities.

Order No. 888 also supported the creation of independent system operators ("ISOs"), which are non-profit organizations charged with operating the transmission grid to ensure open access and managing competitive electricity markets in their territories. ISOs and competitive electricity markets are described in more detail in the next Section. FERC Order No. 2000 helped further the goals of the Energy Policy Act of 1992 by refining the role of ISOs as a type of RTO. Private transmission companies can also become RTOs, although thus far all RTOs have taken the non-profit ISO form.

In the 1990s, 22 states and the District of Columbia enacted legislation to effect deregulation. However, after the 2000-2001 energy crisis in California, seven states halted progress towards deregulation. This includes California, which was already relatively deregulated, but has little retail competition. As of 2015, 15 states and the District of Columbia are deregulated.[130] Now, about two thirds of electricity customers are served by markets in which wholesale prices are set in a competitive market. Some state regulators have also allowed for retail competition. The states' progress towards deregulation is shown in Figure 22.

**Figure 22**

**States' Progress Towards Deregulation[131]**


## Wholesale Power Today

As discussed above, federal policy opened up the wholesale market to competition and aimed to enable greater private investment in generation and open access to transmission. Competitive markets managed by ISOs or RTOs marked a significant change from the past in which p ower was traded through bilateral contracts and power pools. Many power pools converted themselves into ISOs or RTOs after FERC Orders No. 888 and No. 2000. The variety of market arrangements used by ISOs and RTOs and the lack of competitive markets in some states means that wholesale power markets vary greatly across different areas. Altogether, the ISOs and

RTOs serve about two-thirds of demand for electricity in the United States. As shown in Figure 23, large parts of the country remain outside the ISOs and RTOs.

The ISOs and RTOs in Figure 23 are: California ("CAISO"), the Electric Reliability Council of Texas ("ERCOT"), New England ("ISO-NE"), Midcontinent ("MISO"), New York ("NY-ISO"), PJM, and the Southwest Power Pool ("SPP"). The other regions are not served by integrated markets: Northwest, Southwest, and Southeast.[133] In those regions, utilities and generators still buy and sell wholesale power through bilateral or multilateral contracts, because regulation does not allow for competition in wholesale power.

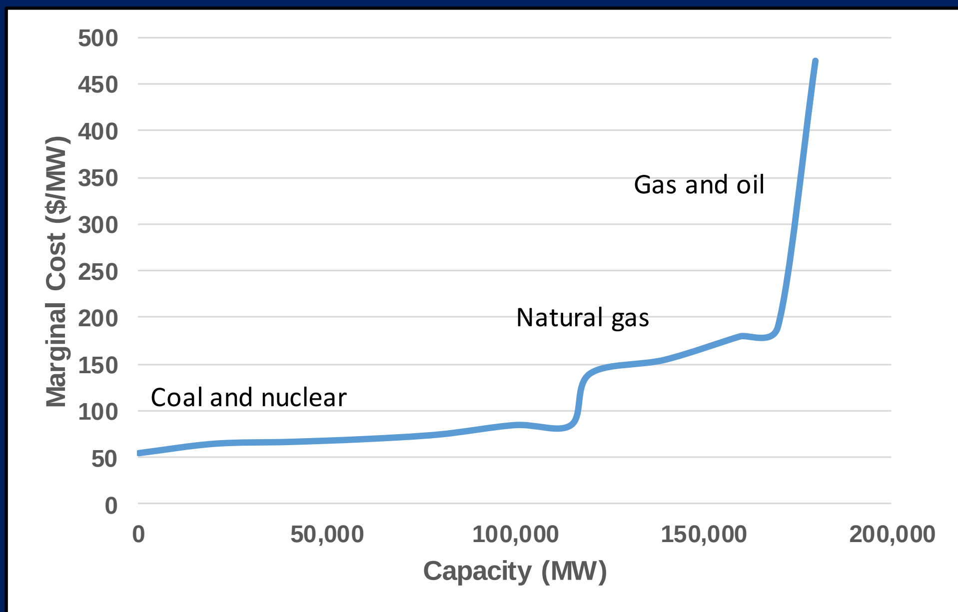
**Figure 23**

**Map of Power Markets[132]**


One of the core functions of ISOs and RTOs is to "dispatch" power plants. This means deciding which power plants should be used, when, and to what extent. Plants are generally dispatched in "merit order," meaning that the cheapest power sources are used first. Sometimes this is not possible due to technical constraints at a given time. A dispatch curve for the PJM market from 2008 is shown in Figure 24. The dispatch curve shows that, as the amount of power being provided increases (horizontal axis), the marginal cost of power rises (vertical axis). Note that oil plants, which exhibit the highest marginal cost of power, were largely used in the far-right end of the curve, when output was highest and cheaper resources were already utilized.

**Figure 24**

**Pennsylvania, New Jersey, and Maryland Pool Dispatch Curve, 2008[134]**




ISOs and RTOs try to forecast power needs in advance to the fullest extent possible. They lock in advance commitments from generators (either through competitive capacity markets or bilateral contracts, depending on the market) and buy commitments on short notice when actual demand exceeds the forecast demand.

The ISOs and RTOs also manage the competitive markets in which generation, as well as ancillary services, can be bought and sold. Ancillary services are electrical services that help the grid maintain service quality.[135, 136] Since ISOs and RTOs are non-profit entities and independent of the market participants, they should be able to plan and manage markets without favoring any of the buyers or sellers. Some markets also include retail competition, in which customers can choose the retailer from which they buy power (although power from various retailers still flows over one distribution grid in a given area). Retail competition is described below in more detail.

ISOs and RTOs ensure open access to the transmission grid and are involved in long-term transmission planning. ISOs price transmission through LMP, which is a variable pricing structure for power based on conditions in different parts of the grid.[137] LMP structures vary between the RTOs and ISOs. LMPs are determined by different factors in different markets, including the quantity of power transmitted; congestion at different points in the grid; and charges for power losses in the grid.

Wheeling charges apply when power is moved between utilities that are not in an ISO or RTO or moved into or out of an ISO or RTO. These charges are intended to cover the cost of providing transmission services. Wheeling charges are approved by state regulators or by FERC when power is wheeled across state lines.

ISOs and RTOs also manage electricity markets in their areas. All the markets trade electricity and ancillary services, but the markets offer different tradable products. Some of the key tradable products on competitive markets are defined below.

- **Capacity:** In capacity markets, generators make longer-term commitments to sell power, and off-takers agree to buy it. Capacity commitments may be made for one or more months in the future or even one year in advance.

- **Day-Ahead Energy:** The day-ahead markets commit generators to produce power, and off-takers to buy power, in a specified hour of the day. These commitments are generally made a few hours before the start of an operating day for each hour in that day.

- **Hour-Ahead Energy:** The hour-ahead markets fill gaps between day-ahead forecasts and what is expected in the immediate future. Generators commit to producer power, and off-takers to buy that power, in specified 5-minute intervals. Generally, the market runs hourly, making commitments for each 5-minute interval in the hour to come.

- **Real-Time Energy:** The real time markets fill gaps between day-ahead or hour-ahead forecasts and the actual requirements on the grid.

- **Ancillary Services:** As mentioned above, ancillary services help maintain service. As with energy, ancillary services are sold in day-ahead and real time markets.

- **Financial Transmission Rights ("FTRs"):** These are hedging instruments which help protect against transmission congestion costs in the day-ahead market. These provide coverage for congestion in a specified path in the transmission grid. Congestion occurs when the demand for moving power over a path in the grid in a certain time period exceeds the amount of power that path can handle. These are often sold in auctions for annual, monthly, and shorter-term products. FTRs have different names in different markets.

- **Virtual Trades:** Virtual trades buy and sell power between two different power markets in the same ISO or RTO (for example, between the day-ahead and hour-ahead markets), but do not require the virtual trader to produce or receive power. This is possible because virtual trades are always offset such that the net impact on power demand is zero – the virtual trader could buy a certain amount of power in the hour-ahead market and then sell that same amount in the day-ahead market (or vice versa). The virtual trader is effectively a middleman between generators in one market and off-takers in another. Virtual trades should cause prices in two markets to converge.

Figure 25 shows which products are traded in the ISOs and RTOs. All markets trade day-ahead energy, real-time energy, ancillary services, and FTRs. All but ERCOT allow virtual trades. Trading of hour-ahead energy and capacity is relatively rare.

| Figure 25: Products Traded in ISO and RTO Markets | | | | | | | |
|---|---|---|---|---|---|---|---|
| **ISO or RTO** | **Day-ahead energy** | **Hour-ahead energy** | **Real -time energy** | **Ancillary services** | **Capacity** | **FTRs** | **Virtual trades** |
| CAISO | ✓ | ✓ | ✓ | ✓ | - | ✓ | ✓ |
| MISO[138] | ✓ | - | ✓ | ✓ | - | ✓ | ✓ |
| ISO-NE | ✓ | - | ✓ | ✓ | ✓ | ✓ | ✓ |
| NYISO | ✓ | - | ✓ | ✓ | ✓ | ✓ | ✓ |
| PJM | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| SPP | ✓ | ✓ | ✓ | ✓ | - | ✓ | ✓ |
| ERCOT | ✓ | - | ✓ | ✓ | - | ✓ | - |

CAISO also manages a wider market for real time energy called the Energy Imbalance Market ("EIM"). EIM includes CAISO's territory and some utilities in seven other states.[139] The utilities outside CAISO are in non-competitive markets (Northwest and Southwest). Expected benefits of EIM include:[140]

- **Price Reduction:** Power prices should fall by reducing use of costly thermal reserves and avoiding transmission congestion charges.

- **Reduced Carbon Emissions:** Use of renewables should increase by expanding the area in which renewable generators can sell power. This should help avoid curtailment of renewables (mandatory reduction of power production). Since intermittent renewable projects cannot control when the sun shines or wind blows, there are times when demand is low enough that those projects must sell less power than they could otherwise produce.

- **Improved Grid Reliability:** Increasing the size of the market will create a wider grid across which to manage congestion, which should help avoid technical problems.

CAISO estimated the value of these benefits as $18.9 million in the first quarter of 2016.[141] CAISO aims to expand the scope of EIM into day-ahead energy, thus effectively creating a regional ISO across the EIMs' territory.

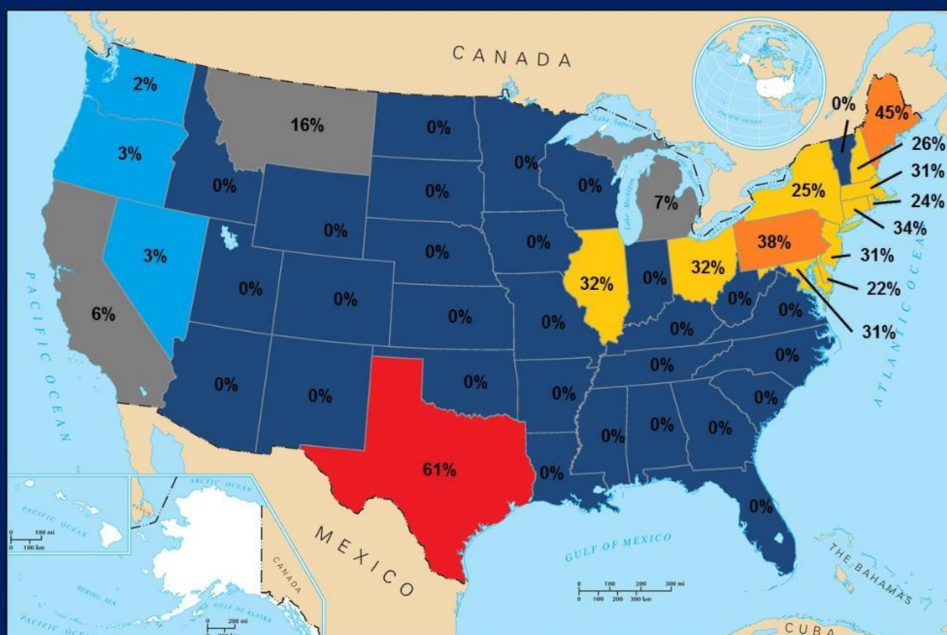
Wholesale power markets and regulation vary significantly across the states. When planning to buy from or finance a generation project, the local regulatory and market conditions have to be understood.

**Retail Competition**

Some ISOs and RTOs have retail competition in their territories, where permitted by state regulators. Under retail competition, only one utility owns a distribution grid in any given area, but other retailers may sell power across the grid to end-users. Retailers that do not own the grid then pay a fee to the distribution utility for using the grid, much like open access in transmission. Customers can choose the retailer from whom they wish to buy power. In many states that allow for retail competition, little power is bought from power retailers. For example, only 8 percent of power in California and 7 percent in Michigan from retailers. However, retailers sell the majority of power in Texas (61 percent), and from 22 to 45 percent in much of the Northeast. This is shown in Figure 26.

**Figure 26**

**Share of Retail Sales from Non-Utility Power Marketers[142]**



# APPENDIX C
# SUMMARY OF PRIMARY FEDERAL LEGAL AUTHORITIES TO PURCHASE POWER

| General GSA Related Authorities | |
|---|---|
| 40 U.S.C. § 501 | • Gives authority to GSA to negotiate public utility service contracts for other federal agencies "for a period of not more than 10 years"<br>• DOD has special exemptions allowing them to leverage certain contract options for periods of up to 30 years |
| FAR Part 41.103 | • GSA delegation of authority<br>• GSA delegates authority to certain other federal agencies and sets forth a process for delegation to others to enable these agencies to purchase power under GSA's authority |
| 42 U.S.C. § 7251 | • Recognition of certain federal agencies that have already been given delegated authority<br>• DOE and DOD have been delegated authority to negotiate utility contracts for periods under 10 years via the Department of Energy Organization Act |
| 42 U.S.C. § 8287 | • Maximum 25 year contracts for the purpose of reducing energy costs and increasing the use of renewable energy<br>• Agencies may enter into contracts to achieve energy savings and benefits ancillary to that purpose<br>• A federal agency cannot establish a federal agency policy that limits the maximum contract term to a period shorter than 25 years |
| 42 U.S.C. § 8256 | • Agencies are authorized and encouraged to participate in programs to increase energy efficiency and for water conservation or the management of electricity demand conducted by gas, water, or electric utilities and generally available to customers of such utilities. |
| **DOD Specific Authorities** | |
| 10 U.S.C. § 2304 | • Contracts: competition requirements<br>• Provides for full and open competition with competitive procedures in accordance with the requirements of this chapter and the Federal Acquisition Regulation. |
| 10 U.S.C. § 2667 | • Leases: non-excess property of military departments and Defense Agencies<br>• Authorizes the lease of lands under the Defense Secretary's control that otherwise are not needed at the time for public use or defined as excess property under 40 U.S.C. § 102.<br>• The lease may not exceed 5 years unless the Secretary determines that a longer lease period would promote national defense or public interest. |

| | |
|---|---|
| | • The lease payment (in cash or in kind) cannot be less than the fair market value of the lease interest.<br>• The lease terms cannot provide for a leaseback in excess of $500,000. |
| 10 U.S.C. § 2686 | • Utilities and services: sale; expansion and extension of systems and facilities<br>• Permits DOD to sell or contract to sell utility services (electric power) to purchasers within or in the immediate vicinity of a military activity if the services are not available from another local source and that the sale is in the interest of national defense or in the public interest. |
| 10 U.S.C. § 2688 | • The Secretary of a military department may convey a utility system, or part of a utility system, to a municipal, private, regional, district, or cooperative utility company or other entity.<br>• Consideration for a conveyance may be an amount equal to the fair market value and may take the form of a lump sum payment or a reduction in charges for utility services.<br>• Contracts normally cannot exceed 10 years, but may exceed 10 years but not more than 50 years, if determined that a contract for a longer term is cost effective |
| 10 U.S.C. § 2913 | • Energy savings contracts and activities<br>• Military departments and Defense Agencies may participate in gas or electric utility programs for managing energy demand or for energy conservation. |
| 10 U.S.C. § 2917 | • Development of geothermal energy on military lands<br>• Authorizes the Secretary of a military department to develop, or authorize the development of, any geothermal energy resource within lands under the Secretary's jurisdiction, including public lands, for the use or benefit of the DOD.<br>• Development cannot deter commercial development and use of other portions of such resource if offered for leasing. |
| 10 U.S.C. § 2922a | • The Secretary of a military department may enter into contracts for periods of up to 30 years for the provision and operation of energy production facilities and the purchase of energy from such facilities. |
| DFARS PGI 241.2 | • Acquiring Utility Services<br>• Defines "definite term contract" as a utility services contract for a definite period of not less than one or more than 10 years.<br>• "Indefinite term contract" means a month-to-month contract for utility services that may be terminated by the government upon proper notice. |
| **DOE / PMA Authorities** | |
| 42 U.S.C. § 7152 | • Transferred functions from DOI relating to electric power and administrative authority for the Southeastern Power Administration, Southwestern Power Administration, BPA, Bureau of Reclamation power marketing functions, and Falcon Dam – Amistad Dam – Rio Grande project to DOE. |
| 16 U.S.C. § 825a | • Sale of electric power from reservoir projects; rate schedules; preference in sale; construction of transmission lines; disposition of moneys |

| | |
|---|---|
| | • Authorizes the Secretary of Energy to transmit and dispose of excess energy generated at Army (Corps of Engineers) reservoir projects at the lowest possible rate (wholesale) to consumers.<br>• Further authorizes the Secretary of Energy to make energy available in wholesale quantities to federally owned facilities. |
| 16 U.S.C. § 825s-1 | • Southwestern area sale and transmission of electric power; disposition of receipts; creation of continuing fund; use of fund |
| 16 U.S.C. § 825s-5 | • Southeastern Power Administration; deposit and availability of advance payments |
| 16 U.S.C. § 831 | • TVA<br>• Authorized to provide and operate facilities to generate electricity at any such dam for "use of the United States or any agency thereof, ... in order to avoid the waste of water power, to transmit and market such power." |
| 31 U.S.C. § 1535,<br>43 U.S.C. § 485h(c) | • WAPA has authority to work as an intermediary in the negotiation of longer term contracts between federal agencies and utility providers |
| 16 U.S.C. § 839c | • Sale of Power<br>• In addition to the authorities to sell electric power, the Administrator of the Bonneville Power Administration is also authorized to sell electric power to federal agencies in the region. |
| 42 U.S.C. § 2204 | • Authorizes DOE to enter into new contracts or modify existing contracts for electric services for periods not exceeding 25 years for uranium enrichment installations |

# APPENDIX D
# FINANCIAL IMPACT ANALYSIS FOR NOTIONAL PROJECT

This analysis was based on a notional federal agency site ("the off-taker") with approximately 59 MW of demand and 425 GWh of usage. The off-taker's bundled cost of electricity from its utility includes energy, demand, and transmission components. To simplify the notional analysis, costs do not include fees, taxes, or administrative costs that could apply. This analysis evaluates a PPA with a fixed escalation rate of 1% for forty years, subscribing for 8 MW of baseload power from an SMR. Therefore, the cost of new power, given as the PPA Rate, will be combined with the cost of other sources of power and will result in a blended post-PPA rate for electricity, which can be compared against the status quo rate.

**Assumptions**

This analysis involves several important simplifying assumptions, including:

- **Bilateral, Firm Power Purchase:** It is assumed that the PPA is signed between the off-taker and SMR owner for firm baseload power. The fixed PPA rate reflects both variable supply and fixed capacity costs; therefore, this analysis accounts for a change in both energy and demand charges from the utility as the SMR electricity substitutes utility power purchases. A failure to deliver under the PPA would result in the utility having to supply power. Therefore, depending on the requirements of the load serving utility, it may impose fixed standby charges.

- **Demand Charges:** It is assumed demand charges will be reduced by the effects of the new generation scenarios on average peak demand for utility power. The specifics for determining changes to demand charges would be found in the tariff of the load serving utility and should be considered in a site-specific analysis. Using the percentage change is a simplification to approximate the result: this location-specific consideration will ultimately reflect the nature of the arrangements among the off-taker, the load-serving utility, and the SMR power producer.

- **Transmission Charges:** It is assumed transmission charges will be the same under the status quo and the new generation scenarios. Transmission charges will need to be factored into off-takers' analyses based on the location-specific considerations.

- **Continuation of Status Quo Costs:** It is assumed that the composition of historical costs not associated with the SMR resemble those in the future.[143]

- **COD/Initial Year in 2025:** This analysis assumes the SMR would be first available for operations following ten years of construction. Status quo costs were escalated between the historical baseline year (2015) and commercial operations (2025).

- **Continuation of Load Profile:** One year of historical usage and billing data was used to establish a baseline for the off-taker's usage and demand.[144] The load profile is assumed to remain the same.

- **Escalation of Non-PPA Rates:** The EIA outlook for future energy costs is used to determine a single CAGR in electricity costs that would not be fixed by the PPA. The specific dataset used is the EIA outlook for end-user industrial electricity prices in the WECC Southwest Region.[145] The assumed forty year length of the PPA establishes the time period to calculate the CAGR.

- **PPA Initial Year Rate:** The PPA Rate is assumed to be $74.40/MWh.[146]

- **PPA Escalation Rate:** The PPA Escalation Rate would presumably be fixed contractually. A fixed 1% annual rate is used in this analysis based on the PPA pro forma modeling.

- **Discount Rate:** The annual costs of electricity under the Status Quo scenario and the post-project scenarios are discounted back to the first year at the U.S. Government's discount rate that aligns with the project timeline. In this case, the thirty-year nominal discount rate is 2.8%.[147]

- **Sensitivities:** EIA presents price outlooks across seven different economic scenarios. In this avoided cost analysis, the highest and lowest resulting CAGRs were used to present the outcome as a range.

Most of the foregoing assumptions are installation-specific and will vary based on location, load profile, market regulation, and tariff structure. Therefore, in developing a financial impact analysis, it is important to develop inputs that reflect site-specific factors, as well as changes that may occur in the future.

**Determining Annual Financial Impact**

The approach for a financial impact analysis consists of several steps targeted at determining the values for the existing conditions (hereafter the "Status Quo" costs) and for estimating costs after giving the effect of the execution of the PPA. The steps are performed to find the avoided cost for the first year of the PPA. The process is then repeated, escalating relevant costs using corresponding escalation rates, to determine how total costs change over time. The annual differences in cost are discounted back to the present using the U.S. Government's discount rate (effective thirty-year rate for 2017 is 2.8%) and added up to find the PPA's net present value of avoided or added costs.

The first step is to establish the Status Quo cost of electricity in actual and unit cost terms. Based on a review of billing and usage data from a 12 month period, the Status Quo cost of electricity was approximately $29.6 million and total usage was 424,637 MWh. On a per unit basis, the Status Quo rate was $69.80/MWh inclusive of energy, demand, and transmission components. The annualized Status Quo energy unit cost was calculated at $34.60/MWh.

The second step is to find the cost of power from the SMR in actual terms and on a per unit basis. The PPA will explicitly state what the price of energy will be, and, in this analysis, the PPA rate is assumed to be $74.40/MWh. For the 8 MW block being considered, the analysis further assumes 68,678 MWh in actual billable production.

The third step is to blend the PPA rate and Status Quo energy unit costs into a blended unit cost. Since the off-taker's load is assumed to remain unchanged, the energy from the PPA will displace some of the Status Quo usage. The proportional share of electricity from the SMR and any residual utility power needed to fill out the load can then be represented as a percentage of total MWh. Status Quo energy costs are escalated from 2015 to 2025 dollars and then blended with the PPA rate (also in 2025 dollars) by taking the weighted average of the two unit costs. This reflects their proportional share of the total usage in MWh and results in a post-PPA blended energy unit cost between $47.61 and $53.25 per MWh.

This analysis assumes that actual charges for demand are reduced by the percentage change in average monthly peak demand. The actual cost is then converted to a unit cost by dividing it by the total MWh load. These unit costs are escalated at the EIA rate from 2015 to 2025 dollars.

The unit cost of transmission, assumed to be unchanged but escalated, is then added to the blended energy rate and residual demand rate. The post-PPA unit costs (energy + demand + transmission) result in an initial, blended cost of electricity between $85.36 and $96.99 per MWh, depending on the annual escalation rate. The Status Quo cost is estimated to be between $85.61 and $99.19 per MWh, again depending on the annual escalation rate.

The last step to finding the first year avoided cost of electricity is to compare the Status Quo cost with the post-PPA cost. If the cost avoidance is positive in a given year, then the PPA is less costly in that year. If the cost avoidance is negative, then the PPA is costlier in that year. In this analysis, the total cost of electricity in the first year of the PPA was estimated at between $36.2 million and $41.1 million. This is between $0.1 million and $0.9 million less than estimated Status Quo electricity costs in 2025, depending on the effective escalation rate.

The figures described above are highlighted in the below chart.

**Comparison of Estimated Unit Costs in 2015 and 2025**

| **Assumed COD Year** | 2015 | 2025 | 2025 |
|---|---|---|---|
| **EIA Escalation Rate** | N/A | 2.06% | 3.58% |
| | | | |
| **Unit Cost of Energy** | $/MWh | $/MWh | $/MWh |
| Status Quo Cost of Energy | $34.60 | $42.44 | $49.17 |
| Post-SMR Blended Energy Unit Cost | $41.04 | $47.61 | $53.25 |
| **Unit Cost of Demand** | $/MWh | $/MWh | $/MWh |
| Status Quo Cost of Demand | $31.88 | $39.11 | $45.31 |
| Post-SMR Blended Demand Unit Cost | $27.46 | $33.69 | $39.03 |

| | | | |
|---|---|---|---|
| **Unit Cost of Electricity (Bundled)** | $/MWh | $/MWh | $/MWh |
| Status Quo Bundled Unit Cost of Electricity | $69.80 | $85.61 | $99.19 |
| Post-SMR Bundled Cost of Electricity | $71.81 | $85.36 | $96.99 |
| **First Year Cost of Electricity (Nominal)** | $ | $ | $ |
| Status Quo Bundled Cost of Electricity | $29,638,790 | $36,354,772 | $42,118,309 |
| Post-SMR Annual Bundled Cost | | $36,247,446 | $41,183,902 |
| (Additional Cost) | | $107,326 | $934,407 |

The findings of the financial impact analysis suggest that the post-PPA cost of electricity in the first year is between 0.3% and 2.2% lower than the off-taker's Status Quo cost in 2025. The energy cost component is approximately 8% to 12% higher than the Status Quo estimate in 2025. As the analysis assumes behind-the-meter generation, demand unit costs decrease nearly 14%. Notably, this change assumes that the blended cost of service of the load serving utility remains unchanged. It is probable that the SMR power will displace one or more specific sources of baseload power which would affect the blended cost of service.

**Estimating Long-Term Cost Avoidance / Additions**

A PPA offers the off-taker the benefit of having a predictable cost profile and serves as a hedge against future electric cost increases. One way to determine the value of this hedge is to compare an estimate of the total additional or avoided cost over the life of a PPA against Status Quo costs over the same period.

To make a comparison over time, this analysis escalated energy unit costs annually. This analysis assumes that the PPA Rate escalates by 1%. The Status Quo energy cost is escalated by two different rates, a High (3.58%) and Low (2.06%) rate, based on a range of CAGRs from the EIA to present the outcome as a range.[148] For example, the Status Quo energy unit cost in 2015 is $34.60/MWh and would escalate to $42.44/MWh in the initial year (2025) under the Low Case and $49.17/MWh under the High Case. The PPA Rate is $74.40/MWh in year one, and by year two would be $75.14/MWh.

The weighted average energy rate is recalculated annually, since rates change every year. In year two of the PPA, this results in a weighted Post-PPA unit cost of energy of $48.47/MWh under the Low Case and $54.85/MWh under the High Case. After blending the rates, the demand and transmission unit costs are escalated by the same blended EIA rate and added back to the blended energy unit cost. Demand and transmission are escalated in this analysis, because the chosen EIA escalation rates are based on outlooks for fully bundled electricity prices, not only energy costs.[149]

This notional impact analysis found that the long-term cost of electricity using an SMR could be lower than the cost of electricity under the Status Quo. This is summarized in the below chart:

**Summary of Avoided Cost Findings**

| Scenario | EIA Low | EIA High |
|---|---|---|
| **EIA Escalation Rate** | 2.06% | 3.58% |
| | | |
| **Nominal Cost - 40 years** | | |
| Status Quo Cost of Electricity | $2,226,341,966 | $3,624,762,425 |
| Post-SMR Cost of Electricity | $2,156,649,841 | $3,354,393,551 |
| Avoided or (Additional) Cost | $69,692,125 | $270,368,874 |
| | | |
| **Net Present Value (in 2015 dollars)** | | |
| Avoided or (Additional) Cost | $25,904,989 | $101,036,675 |

Due to differences in escalation rates and reduced demand charges over a long term, the PPA provides an opportunity for avoided costs by the time the SMR is operational in 2025. The net avoided cost is sensitive to changes in escalation rates. In 2015 dollar terms, the net present value of avoided cost of electricity from a forty year PPA to supply SMR power could be between $25.9 million and $101.0 million less than Status Quo costs. While this estimate is subject to significant uncertainty given the rapid evolution in energy markets, it provides an indication of the potential cost impacts of a PPA for SMR-generated power.

**Summary**

This notional analysis is intended to illustrate a process that can be used to support a business case for entering into a long-term PPA for the SMR-generated energy. While the analysis in this Section represents a rough order of magnitude estimate of cost increases, it involves numerous assumptions that require further analysis and refinement. In particular, site-specific factors and transmission costs play a significant role in deciding whether to adopt a PPA, including expiring agreements, asset retirements, and growth in a competitive wholesale market or integrated transmission networks. If a major asset were being retired, the post-SMR rate could be compared along with scenarios that allow purchases through other means. As the SMR is expected to begin operations several years from now, the Status Quo could shift between now and then.

The purpose of conducting a financial impact analysis was to identify a range of foreseeable outcomes and measure whether they fall within a range of tolerance for decision-making. The decision-maker must balance a number of competing priorities, including policy objectives, limiting market risk exposure, and economics. Financial impact analysis is a tool to assist decision-making in analyzing such considerations over a long-term planning horizon.

**Calculation of Avoided Cost in Detail**

A detailed breakdown of the calculations is shown below.

| | | |
|---|---|---|
| + Status Quo Cost of Energy<br>+ Status Quo Cost of Demand<br>+ Status Quo Cost of Transmission<br>= Status Quo Bundled Cost of Electricity ($2015) | + $34.60/MWh<br>+ $31.88/MWh<br>+ $3.31/MWh<br>= $69.80/MWh | |
| Initial PPA Rate ($2025) | $74.40/MWh | |
| Historical Baseline Usage | 59 MW; 424,637 MWh | |
| Expected Annual SMR Purchases | 8 MW; 68,678 MWh | |
| Residual Utility Purchases (MWh) as a percentage of Baseline | (424,637 – 68,678) / 424,637 = 84% | |
| Residual Utility Demand (MW) as a percentage of Baseline | (59 – 8) / 59 = 86% | |
| Escalation Rate (CAGR from EIA Outlook) | Escalate: 2.06% | Escalate: 3.58% |
| + 2025 Cost of Energy<br>+ 2025 Cost of Demand<br>+ 2025 Cost of Transmission<br>= 2025 Status Quo Bundled Cost of Electricity | + $42.44/MWh<br>+ $39.11/MWh<br>+ $4.06/MWh<br>= $85.61/MWh | + $49.17/MWh<br>+ $45.31/MWh<br>+ $4.71/MWh<br>= $99.19/MWh |
| Proportional Utility Unit Cost of Energy ($2025) | 84%<br>x $42.44/MWh<br>= $35.58/MWh | 84%<br>x $49.17/MWh<br>= $41.22/MWh |
| Proportional PPA Cost of Energy<br>($2025) | 16%<br>x $74.40/MWh<br>= $12.03/MWh | 16%<br>x $74.40/MWh<br>= $12.03/MWh |
| Post-PPA Cost of Energy | + $35.58/MWh<br>+ $12.03/MWh<br>= $47.61/MWh | + $41.22/MWh<br>+ $12.03/MWh<br>= $53.25/MWh |
| Proportional Residual Unit Cost of Demand | 86%<br>x $39.11/MWh<br>= $33.69/MWh | 86%<br>x $45.31/MWh<br>= $39.03/MWh |

| | | |
|---|---|---|
| Post-PPA Bundled Cost of Electricity | + $47.61/MWh<br>+ $33.69/MWh<br>+ $4.06/MWh<br>= $85.36/MWh | + $53.25/MWh<br>+ $39.03/MWh<br>+ $4.06/MWh<br>= $96.99/MWh |
| Status Quo Electricity Cost ($2025) | $85.61/MWh<br>x 424,637 MWh<br>= $36.4 million | $99.19/MWh<br>x 424,637 MWh<br>= $42.1 million |
| Post-Project Cost of Electricity ($2025) | $85.36/MWh<br>x 424,637 MWh<br>= $36.2 million | $96.99/MWh<br>x 424,637 MWh<br>= $41.1 million |
| Avoided Costs of Electricity in Year One ($2025) | $107,326 | $934,407 |

# APPENDIX E
# LIST OF ABBREVIATIONS

| | |
|---|---|
| **BPA** | Bonneville Power Administration |
| **BTU/s** | British Thermal Unit/s |
| **CAISO** | California Independent System Operator |
| **CFPP** | Carbon Free Power Project |
| **COL** | Combined Construction and Operating License |
| **COLA** | Combined Construction and Operating License Application |
| **DG** | Distributed Generation |
| **DOD** | U.S. Department of Defense |
| **DOE** | U.S. Department of Energy |
| **DOI** | U.S. Department of the Interior |
| **EIA** | Energy Information Agency |
| **EIM** | Energy Imbalance Market |
| **EPACT** | Energy Policy Act of 2005 |
| **EPC** | Engineering, Procurement, and Construction |
| **ERCOT** | Electric Reliability Council of Texas |
| **ESPC** | Energy Savings Performance Contract |
| **EUL** | Enhanced Use Lease |
| **FAR** | Federal Acquisition Regulation |
| **FERC** | Federal Energy Regulatory Commission |
| **FPC** | Federal Power Commission |
| **FOAK** | First of a Kind |
| **FTR/s** | Financial Transmission Right/s |
| **GSA** | U.S. General Services Administration |
| **IAEA** | International Atomic Energy Agency |
| **INL** | Idaho National Laboratory |
| **IOU/s** | Investor Owned Utility/ies |
| **IPP** | Independent Power Producers |
| **ISO/s** | Independent System Operator/s |
| **ISO-NE** | Independent System Operator – New England |
| **KW** | Kilowatt |
| **LCOE** | Levelized Cost of Electricity |
| **LGIA** | Large Generator Interconnection Agreement |
| **LMP** | Location Marginal Pricing |
| **LPG** | Liquefied Petroleum Gas |
| **LWR** | Light Water Reactor |
| **MISO** | Midcontinent Independent System Operator |
| **MW** | Megawatt |
| **MWe** | Megawatt Electric |
| **MWh** | Megawatt Hour |
| **NERK** | North American Electric Reliability Council |
| **NOKA** | Nth of a Kind |
| **NPM** | NuScale Power Module |
| **NRC** | Nuclear Regulatory Commission |
| **NUG/s** | Non-Utility Generator/s |
| **NY-ISO** | New York Independent System Operator |
| **OMB** | White House Office of Management and Budget |
| **PJM** | Pennsylvania, New Jersey, and Maryland Pool |
| **PMA/s** | Power Marketing Administration/s |
| **PPA** | Power Purchase Agreement |
| **PTC** | Production Tax Credit |
| **PURPA** | Public Utility Regulatory Policies Act |
| **QF/s** | Qualifying Facility/ies |

| | |
|---|---|
| **REA** | Rural Electrification Administration |
| **REC/s** | Renewable Energy Certificate/s |
| **RTO/s** | Regional Transmission Organization/s |
| **SMR/s** | Small Modular Reactor/s |
| **SPP** | Southwest Power Pool |
| **SPV** | Special Purpose Vehicle |
| **TVA** | Tennessee Valley Authority |
| **UAMPS** | Utah Associated Municipal Power Systems |
| **UESC** | Utility Energy Service Contract |
| **U.S.C.** | U.S. Code |
| **VA** | U.S. Department of Veterans Affairs |
| **WAPA** | Western Area Power Administration |

# APPENDIX F
# ENDNOTES

[1] "Small Modular Reactors (SMRs)," *U.S. Department of Energy Office of Nuclear Energy*, http://www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors.
[2] "SMR Start: Policy Statement on U.S. Public-Private Partnerships for Small Modular Reactors," *Nuclear Energy Institute*, 25 October 2016, http://www.nei.org/CorporateSite/media/filefolder/Policy/SMR%20Start/SMR-Start.pdf.
[3] See discussion of FOAK costs in Section 2.4.
[4] "Omnibus Appropriations Act, 2009," Public Law 111-8, *U.S. Statutes at Large* 123 (2009): 524 et seq.
[5] "Small Modular Reactors (SMRs)," *U.S. Department of Energy Office of Nuclear Energy*, http://www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors.
[6] "SMR Start: Policy Statement on U.S. Public-Private Partnerships for Small Modular Reactors," *Nuclear Energy Institute*, 25 October 2016, http://www.nei.org/CorporateSite/media/filefolder/Policy/SMR%20Start/SMR-Start.pdf.
[7] "Public Buildings, Property, and Works," *U.S. Code* 40, § 591. WAPA has noted that PMAs do not adhere to state law when purchasing electricity for other federal agencies.
[8] "Glossary," *U.S. Energy Information Administration*, https://www.eia.gov/tools/glossary/index.cfm?id=B.
[9] Historically, baseload plants (typically nuclear or coal powered) generally cost more to build but supply electricity at a lower hourly cost. Peaker plants, such as natural gas facilities, can be built relatively cheaply and generally operate at a higher hourly cost, and they can rapidly be brought on- or off-line in response to changes in electricity demand. Some renewable energy sources, such as solar and wind power, are intermittent and are prioritized as electricity sources by grid operators because of green energy usage requirements and their near-zero operating costs when that energy source is available. The intermittent nature of electricity generated by these renewable energy sources can be a challenge for baseload plant operators – including nuclear power plants operators – because the operators cannot increase and decrease their power production to balance it with that of intermittent electricity sources without additional wear on their equipment or less economic power generation.
[10] Laura Martin and Jeffrey Jones, "Effects of the Clean Power Plan," *U.S. Energy Information Administration*, 20 June 2016.
[11] Ibid.
[12] Ibid.
[13] Ibid.
[14] Electricity is sent through the electric grid, which consists of high-voltage, high-capacity transmission systems, to areas where it is transformed to a lower voltage and sent through the local distribution system for use by business and residential consumers. During this process, a grid operator must constantly balance the generation and consumption of electricity. To do so, grid operators monitor electricity consumption from a centralized location using computerized systems and send minute-by-minute signals to power plants to adjust their output – to the extent possible for each type of electric production plant – to match changes in the demand for electricity.

Electricity demand can vary throughout a day, as well as seasonally, so grid operators use baseload plants, intermittent renewable energy, and peaker plants.

[15] "Advances in Small Modular Reactor Technology Developments," *International Atomic Energy Agency*, September 2014, https://www.iaea.org/NuclearPower/Downloadable/SMR/files/IAEA_SMR_Booklet_2014.pdf.

[16] "Small Modular Reactors (SMRS)," *U.S. Department of Energy Office of Nuclear Energy*, http://www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors.

[17] Ibid.

[18] "Business Case for Small Modular Reactors," *Scully Capital Services, Inc.*, 3 October 2014, http://energy.gov/sites/prod/files/2015/12/f27/BusinesscaseanalysisFinalSMRReport10-15-2014.pdf.

[19] "Historical Information," *U.S. Nuclear Regulatory Commission*, last modified 22 July 2016, http://www.nrc.gov/waste/hlw-disposal/historical-information.html.

[20] Stephen Goldberg and Robert Rosner, "Small Modular Reactors: Key to Future Nuclear Power Generation in the U.S.," *The University of Chicago*, November 2011, http://energy.gov/sites/prod/files/2015/12/f27/ECON-SMRKeytoNuclearPowerDec2011.pdf.

[21] "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016," *U.S. Energy Information Administration*, August 2016, https://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.

[22] Cost of electricity is often compared in terms of LCOE – the "all in" cost of generating power, including the cost of fuel, capital costs, fixed and variable operations and maintenance costs, and other costs incurred over the life of a plant. LCOE takes the costs over the life of the plant and spreads them out over the amount of power expected to be produced. EIA does not consider hydroelectric power to be dispatchable. However, it is much more reliable than wind or solar.

[23] It is important to note that a consumer of power from an SMR may not pay LCOE; the price paid by a consumer could be higher than LCOE due to factors such as fees for transmission of power from an SMR, fees to cover distribution utilities' operating costs, and other factors.

[24] LEAD is the cost of power from the earliest SMRs ("first of the first"), which are not close to serving as the basis for future production at scale.

[25] *Adapted from* Stephen Goldberg and Robert Rosner, "Small Modular Reactors: Key to Future Nuclear Power Generation in the U.S.," *The University of Chicago*, November 2011, http://energy.gov/sites/prod/files/2015/12/f27/ECON-SMRKeytoNuclearPowerDec2011.pdf.

[26] *Adapted from* Geoffrey Rothwell and Francesco Ganda, "Electricity Generation Portfolios with Small Modular Reactors," *Argonne National Laboratory*, May 2015, http://energy.gov/sites/prod/files/2014/06/f16/Electricity%20Generating%20Portfolios%20with%20SMRs.pdf.

[27] *Adapted from* "Business Case for Small Modular Reactors," *Scully Capital Services, Inc.*, 3 October 2014, http://energy.gov/sites/prod/files/2015/12/f27/BusinesscaseanalysisFinalSMRReport10-15-2014.pdf.

[28] *Adapted from* "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016," *U.S. Energy Information Administration*, August 2016, https://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.

[29] "NuScale Wins U.S. DOE Funding for its SMR Technology," *NuScale Power*, http://www.nuscalepower.com/about-us/doe-partnership.

[30] "Department of Energy Issues Final $12.5 Billion Advanced Nuclear Energy Loan Guarantee Solicitation," *U.S. Department of Energy*, 10 December 2014,

http://energy.gov/articles/department-energy-issues-final-125-billion-advanced-nuclear-energy-loan-guarantee.
[31] Timothy Cama, "Panel Votes to Extend Nuclear Power Tax Credit," *The Hill*, 21 September 2016, http://thehill.com/policy/energy-environment/297102-panel-votes-to-extend-nuclear-power-tax-credit.
[32] "Annual Report on Federal Government Energy Management and Conservation Programs, Fiscal Year 2013," *U.S. Department of Energy*, April 2015, p. iii, http://energy.gov/sites/prod/files/2015/05/f22/annrep13.pdf.
[33] "Comprehensive Annual Energy Data and Sustainability Performance," *U.S. Department of Energy*, http://ctsedwweb.ee.doe.gov/Annual/Report/Report.aspx.
[34] A Btu is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit, when water is at its greatest density. *See* "British Thermal Units (Btu)," *U.S. Energy Information Administration*, http://www.eia.gov/energyexplained/index.cfm/index.cfm?page=about_btu.
[35] "Comprehensive Annual Energy Data and Sustainability Performance," *U.S. Department of Energy*, http://ctsedwweb.ee.doe.gov/Annual/Report/Report.aspx.
[36] Ibid.
[37] Ibid.
[38] Ibid.
[39] Ibid.
[40] Ibid.
[41] Ibid.
[42] Ibid.
[43] Ibid.
[44] Ibid.
[45] Ibid.
[46] Solar DG in many markets was originally priced by many utilities equal to the cost of delivered electricity (essentially allowing the customer to have its meter reverse direction depending on if it was generating or using electricity). While this was a great deal for customers, utilities realized that they are not recovering the cost of providing back-up service to these customers.
[47] "Procurement Guide for Public Utility Services: A Practical Guide to Procuring Utility Services for Federal Agencies," *U.S. General Services Administration*, August 2015, p. 5, http://www.gsa.gov/portal/mediaId/240463/fileName/Procurement_Guide_for_Public_Utility_Services_08-2015.action.
[48] "Public Buildings, Property, and Works," *U.S. Code* 40, § 591.
[49] *Code of Federal Regulations*, "Acquisition of Utility Services", title 48, sec. 41.
[50] "Joint Resolution: Making further continuing appropriations for the fiscal year 1988, and for other purposes," Public Law 100-202, *U.S. Statutes at L*arge 101 (1987): 1 et seq.
[51] "Public Buildings, Property, and Works," *U.S. Code* 40, § 501.
[52] *Code of Federal Regulations*, "Acquisition of Utility Services", title 48, sec. 41.101.
[53] Ibid.
[54] *Code of Federal Regulations*, "Acquisition of Utility Services", title 48, sec. 41.204(c).
[55] *Code of Federal Regulations*, "Acquisition of Utility Services", title 48, sec. 41.101.204(2).
[56] *Code of Federal Regulations*, "Acquisition of Utility Services", title 48, sec. 41.101. 205(a).
[57] *Code of Federal Regulations*, "Use of Government Sources by Contractors", title 48, sec. 51.205(d).
[58] *Code of Federal Regulations*, Acquisition of Utility Services, title 48, sec. 41.103(a).

[59] Ibid.
[60] *Code of Federal Regulations*, Acquisition of Utility Services, title 48, sec. 41.103(b) and (c).
[61] *Code of Federal Regulations*, Acquisition of Utility Services, title 48, sec. 41.206.
[62] "Public Buildings, Property, and Works," *U.S. Code* 40, § 501(a)(2).
[63] "Armed Forces," *U.S. Code* 10, § 2922(a) and (c).
[64] "Armed Forces," *U.S. Code* 10, § 2922(a).
[65] Ibid.
[66] "Armed Forces," *U.S. Code* 10, § 2922(a)(2).
[67] John Conger, Acting Deputy Under Secretary of Defense (Installations and Environment), "Memorandum for Assistant Secretary of the Army (Installations, Energy and Environment), Assistant Secretary of the Navy (Energy, Installations and Environment), Assistant Secretary of the Air Force (Installations, Environment and Logistics); Subject: Financing of Renewable Energy Projects Policy," 9 November 2012.
[68] "Armed Forces," *U.S. Code* 10, § 2922(a).
[69] "Armed Forces," *U.S. Code* 10, § 2667(b)(4).
[70] "Armed Forces," *U.S. Code* 10, § 2667(b)(1).
[71] "Armed Forces," *U.S. Code* 10, § 2688(a).
[72] "Armed Forces," *U.S. Code* 10, § 2688(c).
[73] "Armed Forces," *U.S. Code* 10, § 2688(c)(1).
[74] "Armed Forces," *U.S. Code* 10, § 2688(d)(2).
[75] "The Public Health and Welfare," *U.S. Code* 42, § 8287(a)(2)(d).
[76] "The Public Health and Welfare," *U.S. Code* 42, § 8287(a)(1).
[77] "Energy Escalation Rate Calculator Download," *Department of Energy*, http://www.energy.gov/eere/femp/energy-escalation-rate-calculator-download.
[78] "About WAPA," *Western Area Power Administration*, last modified 22 November 2016, https://www.wapa.gov/About/Pages/about.aspx.
[79] Extraordinary contract administration would incur additional cost, e.g., performance issues with the vendor.
[80] "Circular No. A-11: Preparation, Submission, and Execution of the Budget," *U.S. Office of Management and Budget*, July 2016, https://www.whitehouse.gov/sites/default/files/omb/assets/a11_current_year/a11_2016.pdf.
[81] "Circular No. A-11: Appendix B—Budgetary Treatment of Lease-Purchases and Leases of Capital Assets," *U.S. Office of Management and Budget*, 2016, https://www.whitehouse.gov/sites/default/files/omb/assets/a11_current_year/app_b.pdf.
[82] Kara Colton, Allison Doman and Seth Kirshenberg, "A Community Handbook on Nuclear Energy," *Energy Communities Alliance*, 2014, https://static1.squarespace.com/static/55c4c892e4b0d1ec35bc5efb/t/5785444b414fb5a47a51163f/1468351564529/NuclearHandbook.pdf.
[83] Ibid.
[84] "Nodal Market Education," *Electric Reliability Council of Texas*, September 2013, http://www.ercot.com/content/wcm/training_courses/14/nodal101_september_2013.pdf.
[85] James Selecky, Kathryn Iverson and Ali Al-Jabir, "Standby Rates for Combined Heat and Power Systems," *Regulatory Assistance Project*, February 2014, http://www.raponline.org/wp-content/uploads/2016/05/rap-standbyratesforchpsystems-2014-feb-18.pdf.
[86] OMB provides guidance on using discount rates for federal investment decisions and contracts. *See* "Circular No. A-94 Revised: Guidelines and Discount Rates for Benefit-Cost

Analysis of Federal Programs," *Office of Management and Budget*, 29 October 1992, https://www.whitehouse.gov/omb/circulars_a094#1.
[87] "Background on the Carbon Free Power Project (CFPP)," *Utah Associated Municipal Power Systems*, http://uamps.com/index.php/38-items/207-backgrounf-cfpp.
[88] "NuScale Technology to be Used at the CFPP," *Utah Associated Municipal Power Systems*, http://www.uamps.com/index.php/38-items/24-carbon-free-power-project?id=208.
[89] Ricotti, Marco E. "Engineering Fundamentals of Modular and Integral PWR-type SMR Designs and Technologies," *Nuclear Reactors Group*, (presentation, International Atomic Energy Agency Technical Meeting on Technology Assessment of Small and Medium-sized Reactors (SMRs) for Near Term Deployment, Chengdu, China, 2 September 2013), https://www.iaea.org/NuclearPower/Downloadable/Meetings/2013/2013-09-02-09-04-TM-NPTD/4_italy_ricotti_ipwr.pdf.
[90] Ibid.
[91] U.S. Department of Energy Use Permit No. DE-NE700065, 17 February 2016, http://www.id.energy.gov/insideNEID/PDF/DOE_UAMPS%20Use%20Permit%20DE-N700065.pdf.
[92] The Status Quo Cost is a blended rate resulting from the current mix of resources available to the utility. A more comprehensive analysis could take into account cost forecasts, decisions made by the utility such as third party energy purchases, or changes to revenue requirements after retired debt that would alter the blended price by the time the SMR was operational.
[93] A comprehensive analysis would examine multiple years of billing data to support an indicative or "test" year for forecasting purposes.
[94] Source: NuScale Power, LLC. Based on a public power financing and the benefit on production tax credits over 40 years, beginning in mid-2025.
[95] "Circular No. A-94 Revised: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs," *Office of Management and Budget*, 29 October 1992, https://www.whitehouse.gov/omb/circulars_a094#1.
[96] See discussion of FOAK costs in Section 2.4.
[97] "Omnibus Appropriations Act, 2009," Public Law 111-8, *U.S. Statutes at Large* 123 (2009): 524 et seq.
[98] Department of Energy, "Quadrennial Energy Review, Transforming the Nation's Electricity System: The Second Installment of the QER," January 2017, https://www.energy.gov/epsa/downloads/quadrennial-energy-review-second-installment.
[99] For example, in the event of the reactor core overheating, the layout of the SMR would allow gravity to naturally facilitate convection cooling of the core and surrounding vessel without the need of an external electrical power source. *See* Dr. Peter Lyons, "The Case for Small Modular Reactors," *U. S. Department of Energy*, (presentation, Nuclear Energy Institute Small Reactor Forum, Washington, DC, 25 February 2015), http://www.nei.org/CorporateSite/media/filefolder/Conferences/SMR/LyonsSMR2014.pdf.
[100] SMRs could also be submerged in below-grid containment vessels, which would increase the seismic resilience of the structures and make plants more disaster-tolerant than surface-level nuclear power plants. *See* "Safety Features of the NuScale Design," *Nuscale Power*, http://www.nuscalepower.com/smr-benefits/safe.
[101] Alexander Glaser, "Small Modular Reactors: Technology and Deployment Choices," *Princeton University*, (briefing, U.S. Nuclear Regulatory Commission, Rockville, MD, 5 November 2014), http://www.nrc.gov/reading-rm/doc-collections/commission/slides/2014/20141105/glaser-11-05-14.pdf.

[102] M. V. Ramana, "Resource Requirements and Proliferation Risks Associated with Small Modular Reactors," *Princeton University*, (presentation, AAAS Annual Meeting, Chicago IL, 15 February 2014).

[103] Though current large nuclear power plants have factory-fabricated elements to their design, the majority of construction work occurs on-site – often facilitated by the utility that will run the plant once fully operational. *See* "Benefits of Small Modular Reactors (SMRs)," *U.S. Department of Energy Office of Nuclear Energy*, http://www.energy.gov/ne/benefits-small-modular-reactors-smrs.

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[112] "International Energy Outlook 2016: Chapter 5. Electricity," *U.S. Energy Information Administration*, 11 May 2016, http://www.eia.gov/outlooks/ieo/electricity.cfm.

[113] "Wheeling," *Independent Energy Producers Association*, http://www.iepa.com/wheeling.asp.

[114] IPPS are also referred to as Non-Utility Generators ("NUGs") or merchant generators.

[115] "United States Electricity Industry Primer," *Department of Energy Office of Electricity Delivery and Energy Reliability*, July 2015.

[116] "Evolution of the Electricity Industry Structure in the U.S. and Resulting Issues," *Navigant*, 8 October 2013, http://www.emrf.net/uploads/3/4/4/6/34469793/evolution_of_the_electric_industry_for_emrf_10-8-13.pdf.

[117] "About NARUC," *National Association of Regulatory Utility Commissioners*, http://www.naruc.org/about-naruc/about-naruc/.

[118] PJM became a Regional Transmission Organization in 2001.

[119] "History of FERC," *Federal Energy Regulatory Commission*, https://www.ferc.gov/students/ferc/history.asp.

[120] Electric cooperatives serve an estimated 42 million in 47 states today, delivering 11 percent of U.S. power consumption. *See* "Co-ops Are an Integral Part of the $364 Billion U.S. Electric

Utility Industry," *America's Electric Cooperatives*, http://www.electric.coop/our-mission/powering-america/.

[121] Rural cooperatives are also involved in nuclear generation. Oglethorpe Power, an association of cooperatives in Georgia, owns 30 percent of two nuclear plants. The REA was replaced by the Rural Utilities Service as part of a 1994 reorganization of the Department of Agriculture.

[122] TVA engages in activities similar to those of PMAs, particularly in transmission and marketing of hydropower. TVA and PMAs are thus often discussed together, although they are established by different legal authorities, and TVA is technically not a PMA. Unlike the PMAs, TVA owns and operates a large fleet of power plants. *See* Victor S. Rezendes, "The Role of the Power Marketing Administrations in a Restructured Electricity Industry," *U.S. General Accounting Office*, (testimony, U.S. House of Representatives Subcommittee on Water and Power, Washington, DC, 24 June 1999), http://www.gao.gov/assets/110/107984.pdf.

[123] "History," *Bonneville Power Administration*, https://www.bpa.gov/news/AboutUs/History/Pages/default.aspx.

[124] "About the Agency," *Southwestern Power Administration*, http://www.swpa.gov/.

[125] "A History of the Southeastern Power Administration (1990-2010)," *U.S. Department of Energy*, http://www.energy.gov/sepa/downloads/history-southeastern-power-administration-1990-2010.

[126] "WAPA History Shapes its Future," *Western Area Power Administration*, last modified 13 June 2016, https://www.wapa.gov/About/history/Pages/History.aspx.

[127] "Key Players," *North American Electric Reliability Corporation*, http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx.

[128] Up until then, the power sector largely consisted of integrated utilities which included generation, transmission, and distribution in one entity. IPPS are also sometimes called NUGs.

[129] John Kwoka, Michael Gerald Pollitt, and Sanem Sergici, "Divestiture Policy and Operating Efficiency in U.S. Electric Power Distribution," *Journal of Regulatory Economics* 39, no. 1 (August 2010):86-109, doi: 10.1007/s11149-010-9122-3.

[130] Claire Lim, "U.S. Electric Utilities and Deregulation: Trends, States' Choice, and Political Environments," *Cornell University*, 30 August 2016, https://lim.economics.cornell.edu/deregulation_main.pdf.

[131] *Adapted from* "Status of Electricity Restructuring by State," *U.S. Energy Information Administration*, September 2010, http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html.

[132] *Adapted from* "Energy Primer: a Handbook of Energy Market Basics," *U.S. Federal Energy Regulatory Commission*, November 2015, https://www.ferc.gov/market-oversight/guide/energy-primer.pdf.

[133] Note the distinction between the Southwest region (no RTO or ISO) and the SPP (an RTO).

[134] *Adapted from* Mostafa Sahraei-Ardakani, Seth Blumsack, and Andrew N. Kleit, "Zonal Supply Curve Estimation in Transmission-Constrained Electricity Markets," *SSR*N, 2 October 2011, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1937411&download=yes.

[135] Jovan Ilic et al, "Power Market Primers: Ancillary Services," *U.S. Department of Energy*, 12 April 2013, p. 1-4, https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=784.

[136] Ancillary services include frequency regulation (generation that balances short-term gaps between power supply and demand) and reactive power (generation that compensates for drops in voltage).

[137] LMP is a type of "nodal pricing," as prices are determined at certain points, or nodes, in the transmission grid.

[138] MISO has administered a voluntary capacity market previously.

[139] EIM access has been offered to 14 states in total. *See* "Energy Imbalance Market (EIM) Overview," *California Independent Systems Operator*, http://www.caiso.com/informed/pages/eimoverview/default.aspx.

[140] "EIM FAQ: Expanding Regional Energy Partnerships," *California Independent Systems Operator*, October 2016.

[141] Lin Xu, "Benefits for Participating in EIM," *California Independent Systems Operator*, 30 April 2016, https://www.caiso.com/Documents/ISO_EIM_BenefitsReportQ1_2016.pdf.

[142] *Adapted from* Severin Borenstein and James Bushnell, "The U.S. Electricity Industry after 20 Years of Restructuring," *The National Bureau of Economic Research*, April 2015, http://www.nber.org/papers/w21113.

[143] The Status Quo Cost is a blended rate resulting from the current mix of resources available to the utility. A more comprehensive analysis could take into account cost forecasts, decisions made by the utility such as third party energy purchases, or changes to revenue requirements after retired debt that woukld alter the blended price by the time the SMR was operational.

[144] A comprehensive analysis would examine multiple years of billing data to support an indicative or "test" year for forecasting purposes.

[145] "Annual Energy Outlook for 2016," *U.S. Energy Information Administration*.

[146] Source: NuScale Power, LLC. Based on a public power financing and the benefit on production tax credits over 40 years, beginning in mid-2025.

[147] "Circular No. A-94 Revised: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs," *Office of Management and Budget*, 29 October 1992, https://www.whitehouse.gov/omb/circulars_a094#1.

[148] "Annual Energy Outlook for 2016," *U.S. Energy Information Administration*.

[149] EIA does provide price outlooks for generation, distribution, and transmission services; however these are more germane to service providers and do not reflect the off-taker's cost of power, as well as the industrial end-user prices applied in this analysis.