FRONT-OF-THE-METER DER PROGRAM DESIGN

Draft Program Proposal

Prepared for Maine Department of Energy Resources

Date: August 27, 2026

DOER welcomes written comments on any aspect of this draft report. In Section 6, DOER identifies specific topics where stakeholder feedback is particularly requested; however, commenters are encouraged to provide input on any matter relevant to the proposed program.

Written comments are due no later than September 11, 2026, and should be submitted by email to DOER@maine.gov. To facilitate review, commenters are requested to, where applicable, identify the report section and topic to which each comment pertains.

ABOUT THIS DRAFT, UPCOMING WEBINAR, AND HOW TO COMMENT

This document is a straw proposal: a draft program design prepared by DNV and Clean Energy Group (CEG) for the Maine Department of Energy Resources (DOER) in response to LD 1777 and published for public review and comment. It describes the program framework currently under consideration, the reasoning behind key design choices, and areas where DOER is specifically seeking stakeholder input. The purpose of publishing the proposal at this stage is to give stakeholders an opportunity to review the proposed approach, identify concerns or implementation issues, suggest alternatives, and provide information that should be considered before DOER finalizes its recommendation to the Maine Public Utilities Commission (MPUC).

Public Webinar

DOER will hold a public webinar on September 2, 2026, from 11:00 a.m. to 12:00 p.m. to walk through the straw proposal, explain the major program design elements, and provide an opportunity for stakeholders to ask questions and provide feedback.

Webinar registration https://mainestate.zoom.us/webinar/register/WN_nu-UgFkyThWqvH_BPjV9ZQ

The webinar is intended to support stakeholder discussion of the proposal; stakeholders are encouraged to review this document in advance and come prepared with questions or comments on the proposed design.

Previously, DOER held the first public webinar on June 25, 2026, and introduced the statutory framework, project objectives, preliminary program concepts, analytical methodologies, and project timeline. DOER presented the initial program design options under evaluation, discussed the economic and technical analyses supporting program development, and invited stakeholder feedback to inform refinement of the proposed program. More than 100 participants attended the webinar. Supporting materials, including the pre-read, presentation slides, and meeting summary, are available on the FTM DER Public Webinar #1 page.

How to Submit Comments

Written comments are due by September 11, 2026, and may be submitted via email to DOER@maine.gov.

To help DOER review and respond to comments efficiently, commenters are encouraged to identify the section of the proposal which their comment addresses and, where applicable, the numbered stakeholder question (see Section 6). Comments are welcome on any aspect of the proposal and do not need to be limited to the specific questions posed in this document.

DOER is particularly interested in feedback that identifies potential benefits, costs, implementation challenges, unintended consequences, or alternative approaches that could improve the program's value to Maine ratepayers.

What Happens Next

Feedback received through the webinar and written comment process will inform the program design update DOER submits to the MPUC by September 30, 2026. DOER will consider stakeholder input as it evaluates and refines the proposed program and will summarize the comments received and DOER's responses as part of DOER's submission.

Under LD 1777, DOER's submission begins the MPUC's review process; it does not itself establish or implement the program. The MPUC may implement the program only upon finding that the benefits to Maine ratepayers exceed the costs.

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1 PROJECT OBJECTIVES & OVERVIEW

The Maine Department of Energy Resources (DOER) is developing a new Front-of-the-Meter (FTM) Distributed Energy Resources (DER) Program. Pursuant to Public Law 2025, Chapter 430 (LD 1777) Section 14 and 35-A M.R.S. §3209-I, DOER will submit a proposed program design to the Maine Public Utilities Commission (MPUC) by September 30, 2026. Following review, the MPUC will implement the program if it determines that the benefits to Maine ratepayers exceed the associated costs.

As defined in statute, the new FTM DER program (Program) should support the continued development of renewable energy resources interconnected to the distribution system on the utility side of customer meters, while developing compensation structures that more accurately reflect the value that DERs provide to the electric system and to Maine ratepayers. Eligible technologies may include, but are not limited to, solar, storage, fuel cells, biomass, and hydroelectric generation resources, so long as they meet statutory requirements and are interconnected within the service territory of a Maine transmission and distribution (T&D) utility.

LD 1777 directs DOER to consider several key design factors as it develops the Program:

- The marginal benefits to ratepayers associated with the time and location of energy generation
- Reasonable compensation rates tailored to DER size and technology type
- The development and application of a value-based compensation model for DERs
- Opportunities to establish a load reduction program for commercial customers
- Incentives for energy storage resources that provide measurable benefits to ratepayers
- Utility system, rate structure, metering, billing, data collection, and operational changes necessary to support program implementation

Beyond these statutory requirements, LD 1777 allows DOER to consider other factors that it deems appropriate. To that end, project consultants DNV and CEG have identified additional objectives, outlined in Table 1-1, that can help ensure the Program achieves long-term success and delivers broad value to Maine stakeholders.

Table 1-1. Guiding project objectives

Objective	Explanation
Affordable energy costs	Program will contribute to lowering electricity costs for ratepayers.
Attractive market for developers	Program incentives support long-term market health without raising costs for ratepayers.
Recognized value streams	Energy services from DER resources are identifiable and compensated appropriately.
Reliable and resilient grid	Program impacts strengthen Maine's grid, protect it against evolving challenges, and support reliable service.
Integrated with grid operations	FTM resources are integrated into planning and operations to provide enhanced services for maximally effective grid management.
Community benefits	Maine people and host communities see material benefits from clean energy investments.
Durable, sustainable market design	Program is flexible enough to adapt to new technologies and market changes.

2 STRAW PROPOSAL

This section describes a potential program design for FTM DERs in Maine. This “straw proposal” applies the insights and lessons of past experience, statutory requirements, approaches used in other jurisdictions, and an understanding of Maine’s current energy and grid needs. The straw proposal is designed to deliver a “stack” of values tied to grid services. DERs can provide a range of grid services—including supplying additional clean energy, stabilizing frequency and voltage, and reducing the need for utility capital investments. The ultimate goal of the program design is to maximize value to Maine ratepayers—and, at minimum, achieve the net benefit threshold required by 35-A M.R.S. §3209-I—by accessing more of these valuable services. The straw proposal accomplishes this through two parallel approaches: first, valuing and compensating verifiable revenue streams and, second, providing a phased roadmap toward additional value streams that compensate advanced capabilities to meet changing system needs.

The straw proposal creates revenue opportunities that compensate multiple grid services. It incorporates industry best practices for utilizing available technologies—distributed generation (DG), storage, and smart inverters—and balances planning-informed deployment with practical needs for program scale and stability.

The proposal is designed around the statutory net-benefit requirement: compensation levels and procurement volumes would be established only where the benefits accruing to ratepayers exceed the associated program costs. Compensation for individual services and value streams would be based on the best available market information, demonstrated performance, and clear and specific requirements. This proposed Program integrates with system planning processes and aligns DER deployment with opportunities that provide the most benefit to ratepayers.

Program Overview

The straw proposal secures clean energy services and time- and location-valued grid services for Maine ratepayers by:

1. Leveraging Maine's existing Standard Offer Service (Standard Offer) program[1] and bundling DER-provided supply components into a defined "Standard Offer Block" integrated into Standard Offer supply.
2. Establishing a separate but compatible and stackable Distribution System Service (DSS) contract process. DSS is a planning-integrated deployment path that supports distribution system needs by providing locationally and temporally defined grid services, compensated on metered performance.

In broad terms, the straw proposal is designed for electric utilities to provide key system information and serve as neutral contract counterparties; project owners to finance, build, and operate projects; and rigorous oversight to ensure cost-effective implementation of the program. The program pays for value that is competitively priced, contractually defined, and demonstrated through measured performance.

DERs participating in the Standard Offer Block would enter into long-term contracts with Maine T&D utilities. These contracts compensate projects for low-cost, clean energy and associated environmental attributes at competitively set prices; the attributes are applied to Standard Offer providers' renewable portfolio standard (RPS) obligations and retired in Maine. Eligible projects may also earn additional compensation through the separate DSS contract for verifiable, location- and time-specific services needed by the distribution system.

Projects in the Standard Offer Block are built and operated to serve the energy supply and RPS requirements of Maine Standard Offer providers; the Block’s aggregated, metered output nets against Standard Offer obligations in the supply solicitations, so suppliers either incorporate the Standard Offer Block into their bids or price the remaining residual load. The Block thereby functions as a long-term clean energy supply hedge, providing time-differentiated energy and environmental attributes for Standard Offer customers. The DSS component builds on this foundation by compensating projects that provide

[1] Maine Statute 35-A M.R.S. §3212, https://legislature.maine.gov/statutes/35-a/title35-Asec3212.html.

additional distribution system value — reliability support, local balancing of supply and demand, and deferral or avoidance of infrastructure investment.

Utility system planning processes, such as Integrated Grid Planning (IGP), identify grid needs and can provide a foundation for determining where and how DERs could provide value to the system. As those processes mature, their results can increasingly inform the sizing of Standard Offer Blocks, the services procured through DSS, and the siting of resources on the grid. In this way, the program can optimize DER deployment to reduce reliance on the bulk power system, defer or avoid capital investment, relieve grid congestion, manage distribution peak demand, and support local reliability and resiliency. By making more efficient use of existing grid infrastructure and avoiding higher-cost system investments, these services can reduce costs for ratepayers.

Additional information on the straw proposal can be found in Section 5 including program eligibility, enrollment, and participation.

LD 1777 and 35-A M.R.S. §3209-I

As described above, LD 1777 (Public Law 2025, Chapter 430), Section 14 and 35-A M.R.S. §3209-I provide DOER with a statutory foundation to design a successor program to Net Energy Billing (NEB) and require the proposal to provide "benefits to ratepayers in the State in excess of the costs to ratepayers."[2] The straw proposal is structured around that net-benefit threshold while incorporating the specific considerations in LD 1777. Each of those considerations communicates a critical need and opportunity for FTM DERs in Maine. Table 2-1 summarizes how each consideration is reflected in the straw proposal.

Table 2-1. LD 1777 considerations in the straw proposal

LD 1777 program design considerations	How the consideration is addressed in the straw proposal
1. The marginal benefit to ratepayers in the State of the time value of generation and the location of generation	The straw proposal secures clean energy during peak and non-peak hours for all electricity users and establishes locationally-and temporally driven grid services that can reduce system costs and support reliability and resilience. Location and timing are informed by utility planning and by bulk system market information.
2. Reasonable compensation rates specific to a distributed energy resource's size and generation type	The straw proposal is technology-agnostic across the technologies enumerated in statute. Transparent compensation rates are set according to grid needs identified through utility system planning processes. This enables ratepayers to realize the benefits of a "best-fit" solution for grid needs. The spectrum of rates and their associated performance requirements are dictated by need.
3. The development and use of a compensation model based on the value of DERs	The straw proposal proposes that compensation rates would be predetermined and transparent. Each grid service provided to ratepayers is measured and substantiated before a project receives compensation, reducing non-performance risk to ratepayers. A project cannot receive double payment for duplicative services.
4. Opportunities for a load reducer program for commercial customers	Although the straw proposal does not expressly provide for load reduction opportunities for commercial customers, future program stages can integrate features that value load management as a grid service.

[2] LD 1777 (Public Law 2025, Chapter 430), https://legislature.maine.gov/legis/bills/getPDF.asp?paper=HP1188&item=8&snum=132.

LD 1777 program design considerations	How the consideration is addressed in the straw proposal
5. Incentivizing energy storage that provides benefits to ratepayers in the State	The straw proposal anticipates that energy storage would be a component of many participating DERs. Revenue streams identify and value a continuum of grid services, including storage. Services that storage can provide, and which could be compensated via this straw proposal, include supporting the grid during peak demand periods, enabling utilities to defer or avoid capital expenses, and providing grid services at the time and location they are most needed.
6. Necessary changes to utility rate structure, billing systems, data collection or metering to implement the program	Initial program stages reflect existing or anticipated utility administrative and operational systems. However, moderate changes to billing systems, data collection, metering, and system planning will be required to fully implement the straw proposal. The proposal is designed to integrate evolving utility IGP processes and network capabilities by using identified system needs to inform the procured grid services.

3 WHAT A DISTRIBUTED ENERGY RESOURCE (DER) PROGRAM SHOULD PROVIDE

This section reviews the benefits that DERs can provide to Maine's energy system and how they can support the state's energy goals. Ultimately, any FTM DER program design should seek to balance the multiple goals, opportunities, and system conditions discussed in this section.

3.1 Maine's energy goals

Maine's legal, regulatory, and strategic energy landscape seeks to promote affordability, reliability, and clean energy for all customers amidst rising customer energy costs, converging pressures on power system infrastructure, and increasing load growth. DERs have the potential to help mitigate these challenges.

The 2025 Maine Energy Plan provides a strategic roadmap to support Maine energy priorities, achieve a 100% clean electricity system by 2040,[3] and deploy at least 400 megawatts (MW) of energy storage by 2030.[4] The Plan identifies DERs as an important tool to achieve these goals and offers several strategies and actions to leverage DERs in pursuit of the Plan objectives listed below.[5]

- Deliver affordable energy for Maine people and businesses.
- Ensure Maine's energy systems are reliable and resilient in the face of growing challenges.
- Responsibly advance clean energy.
- Deploy efficient technologies to reduce energy costs.
- Expand clean energy career opportunities for Maine people and advance innovation.

3.2 How DERs can benefit the energy system

DERs can address grid needs across many dimensions, helping to defer infrastructure upgrades, meet energy demand, and reduce reliance on bulk power system resources. In this way, DERs serve as an alternative to traditional supply sources and utility investments. The following discussion identifies a set of services that DERs can provide to the grid, as well as their additional potential to advance Maine's energy goals. The straw proposal ultimately translates some of these services into a program design that aims to contribute value to ratepayers because it is rooted in planning-based procurement and an investment-deferral framework.

Grid Services

DERs can provide a wide range of services to bulk electricity and distribution systems. The DER Grid Services architecture (established by the U.S. Department of Energy's Grid Modernization Laboratory Consortium (GMLC)) identifies six primary categories of grid services, a taxonomy within which to identify specific grid needs and operational objectives of certain services, which can inform product definitions and compensation.[6,7] Figure 3-1 outlines this taxonomy.

[3] Maine Statute 35-A M.R.S. §3210, https://www.mainelegislature.org/legis/statutes/35-a/title35-asec3210.html.

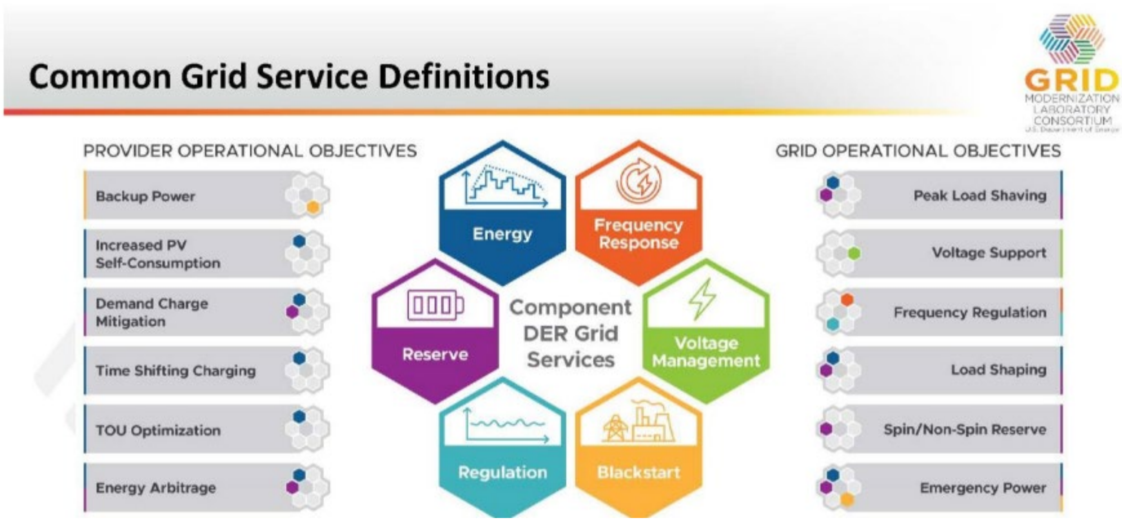
[4] Maine Statute 35-A M.R.S. §3145, https://legislature.maine.gov/statutes/35-A/title35-Asec3145.html.

[5] Maine Department of Energy Resources. "2025 Maine Energy Plan." 2025. https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/energyplan2040.

[6] Kolln J.T., J. Liu, S.E. Widergren, and R. Brown. "Common Grid Services: Terms and Definitions Report." Pacific Northwest National Laboratory. 2023. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34483.pdf.

[7] In some cases, these have different names in specific utility tariffs or organized markets like ISO-NE, which can be used as appropriate to make a DER program fit with corresponding markets and rules.

Figure 3-1. Common grid service terms and the associated objectives



The GMLC organizes DER-provided grid services into six categories that address physical grid needs—ranging from supporting typical electricity demand to ensuring energy resilience when the grid deviates from standard operating conditions.

Power consumption is addressed by **energy service**, a scheduled production of energy at a specific electrical location over a committed period of time.[8] An example of this service is a solar array that sells its energy into the ISO-NE wholesale market, providing energy to meet load needs. Some DERs also can provide **regulation service,** which mitigates and moderates power delivery on a second-by-second (or even shorter) basis, according to grid needs and dispatch signals. In other words, DERs not only provide power but have the capability to regulate how much power is transported in real-time.

However, as grid needs inevitably deviate from this standard (which can happen daily during peak load times, during weather events, and in many other instances), DERs can provide a range of additional services to ensure reliable, safe, and resilient power. These services provide power to the grid at times of need. **Reserve services** (in some instances referred to as capacity) can discharge or turn down load at targeted times to reduce total loading at times and locations as needed. Other system-supporting services include **blackstart,** which re-energizes a portion of the grid when it goes offline. DERs can also provide ongoing, ancillary services to ensure safe and reliable energy delivery, including **frequency response,** which manages frequency levels across the energy system, and **voltage management**, which provides localized voltage moderation support.

Historically, DERs are often contracted for a limited set of these services, primarily energy delivery and some reserve service in the case of load management or peak avoidance, while conventional resources provide the full suite of services to maintain power supply and a stable grid. Realizing a fuller value proposition from DERs, including to unlock their inherent capabilities as a resource sited close to load, requires new contract arrangements and compensation structures that directly reflect additional services.

[8] Kolln, Jaime, Liu, Jingjing, Widergren, Steve, Brown, Rich. "Common Grid Services: Terms and Definitions Report." Grid Modernization Laboratory Consortium, Pacific Northwest National Laboratory, Lawrence Berkeley National Laboratory. 2023. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34483.pdf.

DER benefits and their potential for Maine

Grid services provided by DERs can advance Maine's broader energy goals by addressing increasing demand, promoting resiliency, and providing clean energy to the grid; these in turn can stabilize, curb, and/or reduce energy costs. DERs are particularly well-suited to provide grid services where and when the grid is constrained.[9]

Meet increasing load growth

Maine's electricity demand is projected to increase in the next several years, and could double between 2023 and 2050. Residential electrification drives much of this growth[10, 11] and contributes to shifts in grid operations: The state is currently transitioning from summer energy demand peaks to winter energy demand peaks. Projections for growth in peak energy demand diverge across seasons. Summer peak growth is projected to increase by approximately 10 to 17% by 2030, and winter peak growth is expected to nearly double summer's, rising by 30 to 70%.[12, 13]

Meeting this demand will require a range of interventions, including energy efficiency measures in addition to new energy generation installations. DERs are a tool to deploy supply resources quickly and cost-effectively. DERs can be constructed faster than most large-scale plants and can be cost-competitive. [14]

Furthermore, DERs can provide energy closer to the location of increased demand, reducing the line losses that occur when delivering electricity to customers from far-away energy generation plants. EIA estimates that nearly 5% of energy generated is lost along the T&D system before it gets to the consumer, and Maine shares in this challenge: Versant's average line loss in 2024 was 7.8%.[15, 16] DERs generating or dispatching energy closer to the customer reduces energy loss, ultimately avoiding energy costs for ratepayers.

Advance clean energy goals

Maine aims to be 100% powered by clean energy by 2040 and has made considerable progress toward that goal in recent years. As of 2024, renewables generated 54% of Maine's in-state electricity, fueled by hydroelectric, wind, and solar resources. The remainder of electricity generated in Maine, however, 43.7% still comes from natural gas-fired resources.[17]

Maine also imports 10-20% of its energy from other states and Canada, largely via transmission infrastructure overseen by ISO-NE as well as the Northern Maine Independent System Administrator in Aroostook and portions of Penobscot and Washington counties. Generation across ISO-NE is principally fueled by natural gas (51% of all generation resources in 2024).[18]

DERs can reduce Maine's reliance on fossil fuels by producing more energy in-state and closer to the customers who will use it. For example, if an energy-servicing DER is installed in a constrained transmission zone, it can reduce the need for

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[9] Cutter, Eric, Laundergan, Jeremy, Sontag, Mike, Bonner, Margo. "Compensating DER for Local Distribution Value While Protecting Affordability." Energy+Environmental Economics. July 2026. https://www.ethree.com/wp-content/uploads/2026/07/E3-LVDER-White-Paper.pdf.

[10] Takahashi, Kenji, Carlson, Ellen, Schoff, Aiden Glaser, Fuzaylov, Ariella, Shenstone-Harris, Sarah, Hopkins, Asa S. PhD. Knight, Pat. "Regional Electric Peak Load Forecasts for Maine: Implications of Electrification and ISO-CE CELT Forecast." Synapse, prepared for the Maine Office of the Public Advocate. 2026. https://www.synapse-energy.com/sites/default/files/Synapse%20Maine%20Regional%20Peak%20Load%20Analysis%20%28Final%20Report%29%2024-071.pdf.

[11] System Planning, ISO-New England. "2025 Forecast Report of Capacity, Energy, Loads, and Transmission (2025 CELT Report)." 2025. https://www.iso-ne.com/static-assets/documents/100035/2026_celt.xlsx

[12] Ibid.

[13] These projections reflect the full range (lowest to highest) for summer peaking, but only the medium range for winter peaking, which could be significantly higher if heat pump adoption surpasses current expectations.

[14] Lazard. "Levelized Cost of Energy +." 2026. https://www.lazard.com/media/kcfconhf/lazards-lcoeplus_vf.pdf.

[15] Energy Information Administration. "Frequently Asked Questions: How much electricity is lost in electricity transmission and distribution in the United States?" 2023. https://www.eia.gov/tools/faqs/faq.php?id=105.

[16] Versant Power, "Line Loss Factors, 2024." Last accessed: August 13, 2026. https://www.versantpower.com/suppliers-and-partners/rates/line-loss-factors/.

[17] Maine Department of Energy Resources. "Maine Energy Profile." 2026. Last accessed: August 11, 2026. https://www.maine.gov/energy/about/energy-profile

[18] Murphy, Dean, Raushkolb, Noah. Vincent, Paige. Brattle Group, prepared for the Maine Department of Energy Resources. "Factors Driving Electricity Prices in Maine." 2026. https://www.maine.gov/energy/sites/maine.gov.energy/files/2026-02/Factors%20Driving%20Electricity%20Prices%20in%20Maine%20Feb%202026%20Brattle%20for%20DOER.pdf.

increased energy generation purchased from the ISO-NE wholesale electricity market. This can also reduce system costs for ratepayers by eliminating the need for T&D system infrastructure investments.

Infrastructure investment deferrals: locational value & avoided costs

Utility capital expenses, such as infrastructure investments, are typically recovered from ratepayers, which can increase utility bills for Maine residents and businesses. Distribution system investments account for the largest portion of capital expenditures across the United States—32% of total expenditures in 2025—and their share of total grid expenses is increasing.[19] Maine shares this trend: Residential ratepayers have seen substantial increases in their monthly electric bills. Between 2016 and 2026, electricity prices for residential customers have doubled on average across Maine's utility territories, including in some cases a 40% increase in distribution prices.[20]

While DERs cannot completely address all of the necessary investments that must be made to the distribution grid, they can defer, mitigate, or eliminate the need for a subset of traditional distribution investments.[21] According to the Lawrence Berkeley National Laboratory, infrastructure investment deferral value is the primary location-specific benefit of DERs.[22] When distribution capacity cannot meet load needs (either current or projected), DERs can be deployed to specific locations and dispatched at specific times to help meet those needs. For example, a distribution feeder might be constrained as local demand increases (due to electrification or other large load development) and thus slated or suited for significant capital investment. A DER such as a solar PV or a battery installed at a constrained point along this feeder would extend the feeder's capacity to serve customers without requiring additional capital investment. In this example, the DER installation can avoid distribution system costs and maintain ratepayer affordability. The same principle also applies to transmission system avoided costs.

This benefit, however, is often limited to circumstances where DERs are installed at locations according to specific grid needs. Services that are compensated without regard to specific grid constraints, such as location or time, can leave potential distribution capital costs unaddressed. For this reason, a single system-wide rate may risk incentivizing resources that do not defer substantial costs, ultimately leading to higher costs for ratepayers because of the other costs associated with the DER installation.[23, 24]

Reliability and Resilience

DERs can advance the state's reliability and resilience goals. Because DERs are typically dispersed across the distribution grid, resources that are appropriately equipped, protected, and interconnected for islanded operation—including resources participating in configured microgrids—can provide local power during certain outages or support restoration of isolated grid segments. DERs can also provide voltage and frequency stability on portions of the grid.[25]

Additionally, DERs can be scheduled to dispatch more or less energy based on anticipated needs, reducing stressors on the grid that might lead to brownouts or overload. For example, DERs can serve as load reducers during periods of grid stress, such as Maine's monthly peak hours. DERs are not simply static generators and dispatchers; through curtailment, demand-response, and other services, they can respond to grid needs to ensure security, safety, and resiliency.

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[19] Electric Edison Institute. "Strengthening America's Energy Infrastructure to Increase Reliability & Lower Costs. Industry Capital Expenditures – 2025 Projections." https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/IndustryCapexReport.pdf.

[20] Maine Department of Energy Resources Website. Last accessed August 11, 2026. https://www.maine.gov/energy/electricity-prices.

[21] Mims Frick, Natalie, Snuller Price, Schwartz, Liza, Hanus, Nichole, Shapiro, Ben. "Locational Value of Distributed Energy Resources." Lawrence Berkely National Laboratory. 2021. https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf.

[22] Though DERs can promote deferrals of investments, rather than fully avoided costs, this can reduce the ultimate cost of investments when they do occur due to the time value of money (TVM).

[23] McDonnell, Matt, Nelson, Ron, Mims Frick, Natalie. "Distributed Energy Resource (DER) Integration Framework: Regulatory Innovation for DER Compensation and Cost Allocation." Lawrence Berkeley National Laboratory and Current Energy Group. 2026. https://emp.lbl.gov/publications/distributed-energy-resource-der.

[24] Cutter, Eric, Laundergan, Jeremy, Sontag, Mike, Bonner, Margo. "Compensating DER for Local Distribution Value While Protecting Affordability." Energy+Environmental Economics. July 2026. https://www.ethree.com/wp-content/uploads/2026/07/E3-LVDER-White-Paper.pdf.

[25] Cutter, Eric, Laundergan, Jeremy, Sontag, Mike, Bonner, Margo. "Compensating DER for Local Distribution Value While Protecting Affordability." Energy+Environmental Economics. July 2026. https://www.ethree.com/wp-content/uploads/2026/07/E3-LVDER-White-Paper.pdf.

3.3 Status of DER deployment in Maine

Maine has seen a significant increase in DER deployment in the past 10 years. Annual community solar installations peaked in 2024 with 450 MW. Since the implementation of NEB and related renewable-energy policies, Maine has installed or has received requests to install a significant amount of solar, solar-plus-storage, and storage-only capacity, including:[26]

- 1,743 MW of existing solar, of which 937 MW participated in the original community solar NEB program[27]
- 42 MW of existing solar-plus-storage projects[28]
- Over 250 MW of energy-storage resources[29]
- Another 400 MW of *proposed* solar and 20 MW of *proposed* solar-plus-storage projects.[30]

With the passage of LD 1777 by the Maine Legislature in 2025, new front-of-the-meter DERs are no longer eligible for participation in NEB.

3.4 Integrated Grid Planning to best utilize DERs

Maine's Integrated Grid Planning (IGP) framework under 35-A M.R.S. §3147 provides an important reference for the design and operation of a FTM DER program.[31] The law requires CMP and Versant Power to develop ten-year grid plans that evaluate future load growth, DER adoption, energy storage deployment, grid reliability, resilience, and opportunities to cost-effectively integrate distributed resources. Importantly, the IGP framework requires the utilities to coordinate elements of the grid plans with Maine's State Energy Plan, the Efficiency Maine Trust triennial plan, and additional relevant reports and analysis completed by other state agencies, aligning utility planning and broader state energy policy objectives.[32]

IGPs may be structured to provide many information inputs needed for a value-based DER program, including:

- Hosting capacity analysis
- Locational benefits of DERs and areas of existing or potential congestion[33]
- Load forecasts with and without DERs
- Energy storage installations
- Analysis of technologies enabling load management and flexibility
- DER capacity by location via grid monitoring

As a result, future IGPs can provide a data-driven foundation for identifying where DERs would provide the greatest value to the electric system.

The first round of utility filings highlights the growing role of DERs in Maine's grid. CMP filed its IGP in December 2025, and Versant filed in January 2026. Together, the plans identify approximately 1,400 MW of existing installed DER capacity and an additional 480 MW of future resources in interconnection queues. Versant expects significant expansion of both behind-the-meter (BTM) and FTM resources through 2033.[34] CMP forecasts DG capacity reaching approximately 1,600 MW by 2034.

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[26] Kinross, Andrew, "Maine's Commnity Solar program becomes second largest in the country amid lucrative rates." Power Advisory LLC. 2025. https://www.poweradvisoryllc.com/reports/maines-community-solar-program-becomes-second-largest-in-the-country-amid-lucrative-rates.

[27] Maine Department of Natural Resources (DOER). "Solar." 2026. Last accessed: August 24, 2026. https://www.maine.gov/energy/initiatives/renewable-energy/solar

[28] Central Maine Power. "Integrated Grid Plan." Exhibit 2.10 & 2.18. 2025. https://www.cmpco.com/documents/d/cmp/cmp-integrated-grid-plan.
Versant Power. "Integrated Grid Plan: Planning a Resilient Grid for a Sustainable Future." 2026. Tables 2-10 & 2-14. https://www.versantpower.com/docs/default-source/environmental/111424-integrated-grid-planning-forecasting-approach-compressed.pdf?sfvrsn=cb51c6b_1

[29] Maine Department of Natural Resources (DOER). "Energy Storage." 2025. Last accessed: August 24, 2026. https://www.maine.gov/energy/initiatives/renewable-energy/energy-storage

[30] Central Maine Power. "Integrated Grid Plan." Exhibit 2.10 & 2.18. 2025. https://www.cmpco.com/documents/d/cmp/cmp-integrated-grid-plan.
Versant Power. "Integrated Grid Plan: Planning a Resilient Grid for a Sustainable Future." 2026. Tables 2-10 & 2-14. https://www.versantpower.com/docs/default-source/environmental/111424-integrated-grid-planning-forecasting-approach-compressed.pdf?sfvrsn=cb51c6b_1

[31] LD 1959 (Public Law 2021, Chapter 702), as amended by LD 1726 (Public Law 2025, Chapter 293).

[32] Maine Statute 35-A M.R.S. §3147, https://legislature.maine.gov/statutes/35-a/title35-Asec3147.html.

[33] Maine Statute 35-A M.R.S. §3147(D)(3), https://legislature.maine.gov/statutes/35-a/title35-Asec3147.html.

Additionally, both utilities' current IGPs recognize that DERs should be deployed for values beyond standard generation, adding grid-service solutions targeted to identified distribution system needs.

CMP's plan identifies demand response, DG, and battery storage as tools to address forecasted grid needs. The plan additionally notes that demand response can reduce peak demand and potentially delay or eliminate upgrades, DERs can offset load, and battery storage can provide peak-shaving and other flexibility services, which has the potential to "reduce strain on the grid and potentially defer or mitigate the need for infrastructure upgrades."[35]

Versant's plan similarly evaluates non-traditional solutions against specific distribution system needs and expressly identifies battery storage and other DER/non-wires alternatives (NWA) resources as potential alternatives to conventional infrastructure. The plan further describes circumstances in which targeted battery storage, DER, or NWA solutions could serve as capital-deferral mechanisms by addressing localized increases in load that would otherwise trigger major system upgrades.[36]

Taken together, these IGPs provide a planning foundation for identifying where DERs could address distribution system needs as alternatives to, or a means of deferring, traditional infrastructure. The plans identify system needs at a planning level; however, they do not yet provide the project-specific details needed to match a DER to an identified system need.

The plans also do not establish mechanisms to procure and compensate DERs for providing the distribution grid services that could be identified through the planning process. The straw proposal's DSS component is intended to provide a pathway toward addressing this gap. Under the proposed Program, information developed through the IGP process could inform the identification of distribution system needs suitable for DER solutions, with subsequent utility analysis defining the location, timing, performance, and other requirements necessary to procure DER services capable of addressing those needs.

The straw proposal therefore does not create a parallel distribution-planning framework or assume that the IGPs themselves provide sufficient information to support DER deployment. Rather, it proposes a framework through which actionable needs identified through the utilities' existing planning processes can be further defined and translated into opportunities to procure and compensate DER services that cost-effectively address those needs.

3.5 DER compensation models

As installed capacity of DERs increases and, with it, interest in the expanded services those assets can provide and the impact of these services on ratepayers, compensation structures need to reflect more granular details of costs and benefits offered by distributed resources. Lawrence Berkeley National Lab (LBNL)'s Distributed Energy Resource Integration Framework provides one approach that would recognize additional value streams while aligning compensation with costs and benefits to ratepayers and the grid.[37] This structure can support asset siting and operation that serve grid needs (integrate with operation rather than be paid a proxy rate for estimated grid services) and provide a tariff-based contracting structure that is compatible with common regulatory rules.

Table 3-1 captures the ways in which the LBNL Framework provides direction to manage compensation and cost allocation.

Table 3-1. LBNL Framework direction to manage compensation and cost allocation

Compensation	Cost Allocation
Compensation for an expanded set of grid services, which can evolve over time.	Improved methods to evaluate and assign costs for grid upgrades and use.

35 Central Maine Power, "Integrated Grid Plan." 2025. https://www.cmpco.com/documents/d/cmp/cmp-integrated-grid-plan.

36 Versant Power. "Integrated Grid Plan: Planning a Resilient Grid for a Sustainable Future." 2025. https://www.versantpower.com/docs/default-source/environmental/versant-power-igp-report-01122026.pdf?sfvrsn=db08dda1_1.

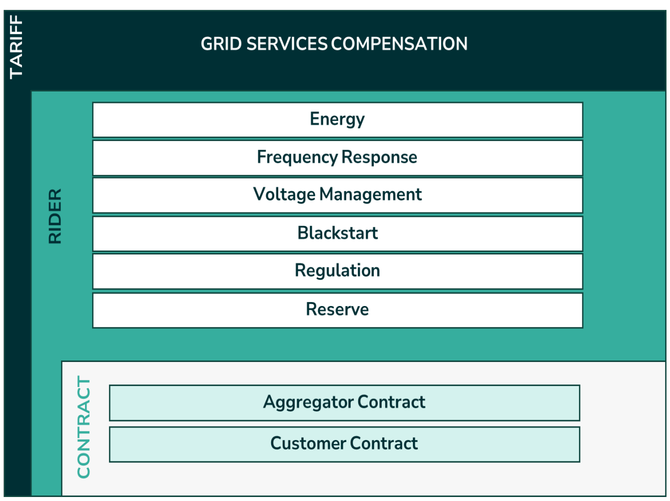
37 McDonnell, Matt, Nelson, Ron, Mims Frick, Natalie. "Distributed Energy Resource (DER) Integration Framework: Regulatory Innovation for DER Compensation and Cost Allocation." Lawrence Berkeley National Laboratory. 2025. https://eta-publications.lbl.gov/sites/default/files/2025-02/der_integration_framework_final_20250117.pdf.

Compensation	Cost Allocation
Encourages value stacking while avoiding double-payment, tier bypassing, other risks.	Promotes contract rules for flexible, right-sized, and sped-up interconnection

Under the LBNL Framework, DER asset owners pay an export charge to defray the costs of their integration with and use of the grid. An appropriately structured charge, derived from established cost-causation principles, has the potential to transparently account for DERs' use of and value derived from the grid, while supporting the increased value of additional services delivered and providing commensurate opportunities for increased revenue.

The LBNL Framework also proposes a rules-based contracting approach that would be compatible with common utility tariff structures, illustrated in Figure 3-2. This approach draws upon a conceptual model introduced by the Hawaiian Electric Companies, later adapted for select DER programs in Hawaii. The approach imagines a fixed, regulator-approved tariff (or set of tariffs) that govern program rules and requirements, within which a set of riders can be used to define specific grid services and compensation amounts. Those riders might be updated more frequently than the tariff (e.g., annually or on an as-needed basis), providing a stable program design that flexibly responds to market updates or changing conditions. In addition, bilateral contracts between applicable parties (e.g., utility to aggregator, aggregator to asset owner, or utility to customer) must be compliant with the tariff and relevant riders while also flexible to their own contract terms or innovative features.

Figure 3-2. Nested contract structure for DER compensation



It may not be appropriate to incorporate all elements of the LBNL Framework into Maine's next FTM DER program. For example, the Framework applies to BTM and FTM distribution-connected resources, while this program is specifically focused on FTM DERs.

4 APPROACHES CONSIDERED

The project consultants considered several program approaches, assessing distinguishing features, which grid services they recognize and compensate, the benefits and drawbacks of each design, and how each approach aligns with Maine's electricity context. Per the statutory requirement of LD 1777, the project team also considered value of DER and load reduction program designs, primarily as optional features of an FTM DER program. Additionally, the project team included feedback provided at a public webinar held June 25, 2026, and additional feedback sessions with key stakeholders.

The straw proposal put forth in this report draws on this review to develop an approach tailored to Maine's specific context and needs. This section reviews these approaches and how they were reflected in the straw proposal.

4.1 Avoided Cost approach

The avoided cost approach creates a standalone program designed to promote market predictability through uniformity—often with equivalent, administratively determined compensation for all projects, regardless of location. Under an Avoided Cost program, long-term project contracts (e.g., 20 years) define a common, narrow set of performance obligations (e.g., energy and capacity value). Table 4-1 summarizes distinguishing features of the Avoided Cost approach.

Table 4-1. Distinguishing features of the Avoided Cost approach

Feature	How it works for Avoided Cost
Program structure	All program elements are designed to **support scalable, common structures and resource functions** (e.g., pre-set compensation rates). Contract terms are standard, regardless of size, location or other project features.
Asset management	**Assets require minimal management,** excluding specific, pre-determined circumstances established in program rules (e.g., time-varying prices, curtailment). Additional capabilities, such as flexible interconnection, can be incorporated into program rules and asset control protocols.
Value streams	**Compensation levels are determined by analytically derived values,** rather than competitive price determination or payment for actual services. A **range of grid- and non-grid-services** can be compensated (e.g., estimates of energy and capacity values, induced price effects, and environmental attributes).

Deployed Avoided Cost programs: Massachusetts' Solar MA Renewable Target (SMART) Program | Massachusetts' Clean Peak Standard | Rhode Island's Distribution Connected Energy Storage Tariff

4.2 Distribution First approach

This approach relies on resource planning and identified network requirements to define project needs or operating requirements, prioritizing distribution grid needs by siting resources close to demand. Under a Distribution First program, distribution system planning processes are essential to asset deployment. Wholesale market values can be recognized, but the focus remains on distribution system balancing settlements. Table 4-2 summarizes distinguishing features of the Distribution First approach.

Table 4-2. Distinguishing features of the Distribution First approach

Feature	How it works for Distribution First
Program structure	**Distribution grid services are prioritized** and secured in long-term agreements, procured through one of two options: 1. **Competitive solicitations** to meet specific grid needs 2. **Open enrollment** that is tariff-informed by avoided cost or utility-identified grid needs
Asset management	Resources can be **aggregated by the utility or a third-party aggregator** and dispatched according to contract agreements, which can include more advanced grid services such as voltage support and distribution capacity management. **Advanced capabilities** (e.g., flexible interconnection, advanced distribution management systems (ADMS), distributed energy resource management systems (DERMS)) can support expanded management capabilities and provide higher value.
Value streams	**Distribution grid services drive value streams and are informed by utility plans**. Value streams can **be locational and non-locational**, including: energy, capacity, T&D capacity, environmental attributes, congestion relief, managed peak demand, resiliency.

Deployed Distribution First programs: Colorado's Distributed Dispatchable Generation (DDG) | Hawaii's Renewable Dispatchable Generation (RDG) | New York's Value of Distributed Energy Resources (VDER) | United Kingdom's Flex Markets

4.3 Wholesale First approach

This approach facilitates projects that are built and operated to participate in wholesale markets, including through FERC 2222 standards.[38] Projects derive revenue from bulk system markets, including energy, capacity, and ancillary service payments. Distribution-level services could be possible on a limited basis, but they are not the primary siting or operational focus of DER resources in this program design. Table 4-3 summarizes distinguishing features of the Wholesale First approach.

Table 4-3. Distinguishing features of the Wholesale First approach

Feature	How it works for Wholesale First
Program structure	Wholesale market participation could be arranged through direct **access to organized wholesale markets** or an aggregation platform under FERC Order 2222. In Maine, for example, third-party aggregators or utilities could administer enrollment, but ISO-NE or NMISA would provide the settlement platform for DERs.
Compensation model	Compensation for wholesale products could **follow market-based, short-term settlement at ISO-NE clearing prices.**
Value streams	**Primary value streams could include wholesale energy, FCM capacity, and ancillary services.** A locational variant might layer in distribution-level services, potentially compensated using an AESC-based price structure for those secondary values. However, attention is needed to avoid competing dispatch or double payment concerns.

Deployed Wholesale First programs: Minnesota's Xcel Energy Capacity*Connect program

38 FERC 2222 was issued by the Federal Energy Regulatory Commission (FERC) in 2020, with updates in 2021, with a goal to better enable DERs to participate in the electricity markets run by regional grid operators by enabling bundling of resources (called an aggregation), with the aggregator being a direct participant in the regional energy markets. More details on FERC 2222 can be found here: https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy.

4.4 Other program design considerations: Load Reduction Programs and Non-Wires Alternatives

Load reduction programs generally incentivize customers to reduce or shift consumption or self-supply rather than pay for a generation or storage asset to inject power onto the grid. LD 1777 directs consideration of a load reduction program for commercial customers, which would entail different or additional features than the FTM DER program that is the primary focus of this report. Maine has existing demand-side programs administered by Efficiency Maine Trust. Programs include compensating commercial and residential customers for reducing or shifting load. These programs represent what is generally considered BTM customer participation, which is a more common deployment than FTM load reduction programs.

Load reduction can complement the FTM DER and storage concepts with which this report is concerned, but it may be complicated to integrate commercial load reduction with an FTM program under Maine's current rules and administrative structures. The project team considered options for load reduction programs but concluded that near-term program development is best suited for DER and storage technology solutions that adhere to the FTM construct.

A non-wires alternative (NWA) design uses portfolios of DERs in place of a specific, identified distribution capital investment, rather than compensating DERs for generic energy, capacity, or ancillary value. NWA value is sometimes narrowly defined as the deferred or avoided capital cost of the identified traditional wires upgrade over a defined time horizon, rather than through a broader payment structure for energy and other services. NWAs are the subject of increasing attention across the U.S., given their potential to reduce expanding capital budgets.

Because value is tied to a specific capital project, procurement and siting is closely coupled with planning, targeting specific locations identified through utility planning processes. Procurement is sometimes structured as a facilitated competitive utility solicitation or, alternatively, as part of a program that targets efficiency or other alternative operating solutions in areas of need. Maine's existing NWA effort as described in statue 35-A M.R.S. §3132-C[39] requires NWAs to be evaluated when T&D utilities identify certain proposed transmission or distribution projects needed for reliability, load growth, or system performance.

4.5 Benefits and drawbacks of approaches considered

In practice, none of these approaches are rigidly defined, and programs often combine or blend various features based on specific context and needs. For example, the Distribution First approach assumes that programs are integrated with robust distribution-system planning processes, which then inform market solicitations for projects that meet identified grid needs. Capabilities such as these, however, may not be immediately available and a Distribution First program may be limited by developing planning capabilities.

Table 4-4 summarizes the benefits and drawbacks of the three primary approaches that the project team considered.

Table 4-4. Benefits and drawbacks of approaches considered

Approach	Benefits	Drawbacks
Avoided Cost	• Relatively simple to administer • Revenue, price certainty for developers • Recognizes grid values that are difficult to observe, validate	• Prices can be high or low (due to analytic valuation) • Available information can limit optimal resource design and siting

[39] Maine Statute 35-A M.R.S. §3132-C, https://legislature.maine.gov/statutes/35-a/title35-Asec3132-C.html.

Approach	Benefits	Drawbacks
Distribution First	• Recognizes more of DERs' inherent values, including proximity to load • Opportunities to provide services incorporated with distribution network management can magnify benefits beyond energy or capacity offsets	• Inconsistent or dynamic system needs and applicable solutions can create diverse contract requirements • Contingent on maturity and capacity of utility planning processes, such as IGPs
Wholesale First	• Offers a competitive, transparent approach • Leverages existing market structures and available tariffs • Larger markets have potential for greater profit for developers	• May not unlock distribution-system values • There is no pre-set rate, which can make projects harder to finance • Could overlook or add to costs of distribution network upgrades

Independently, these programs cannot satisfactorily achieve the identified objectives for Maine's next DER program. Standalone programs, whether based on existing rates or avoided costs, prioritize simplicity, scalability, and ease of participation, but may not ensure DERs are deployed where they provide the greatest grid value. A Wholesale First approach, meanwhile, overlooks distribution system needs and value potential, and fails to provide revenue certainty that is easily financeable for project development. Planning-driven Distribution First programs prioritize optimization and alignment with grid needs but are difficult to implement because planning methods, tools, and processes for DERs are still maturing. As a result, planning-driven programs are often viewed as the long-term ideal, while standalone programs remain a practical way to support DER deployment today.

Between these paradigms, many hybrid forms are possible. In practice, emergent program structures across the U.S. tend to occupy this hybrid domain. These can use the attractive features of a standalone program, including common contract structures or transparent prices, while leveraging utility planning information to inform locational targeting or price-setting for a subset of grid services within the "value stack."

The straw proposal offered in this report seeks to account for all of these dimensions and can provide greater certainty for the most well-established grid services. It also creates options for additional price support and performance opportunities that will leverage new utility planning requirements and anticipated capabilities such as flexible interconnection and advanced distribution management systems (ADMS), unlocking incremental value for Maine ratepayers. Section 5 provides a more detailed overview of the straw proposal.

5 DETAILED STRAW PROPOSAL

This section details the straw proposal for a FTM DER program in Maine and addresses administrative, technical, and operational program parameters.

The straw proposal consists of two complementary components. Part 1, the Standard Offer Block, procures and bundles supply products as a volumetric “block” that provides energy and Maine Class I and Class IA RECs, to serve a portion of the energy supplied to customers receiving utility Standard Offer default service. These products are secured through long-term contracts under a capped, open enrollment tariff structure. The existing Standard Offer Bid Solicitation process would continue to select suppliers to serve the remaining Standard Offer load, while the DER block would reduce the volume of supply procured through that process and provide a long-term price hedge for Standard Offer customers.

Under the straw proposal, the volume procured through each Standard Offer Block would be known in advance and incorporated into the Standard Offer procurement, reducing the load obligation Standard Offer providers must price and serve.

Part 2, Distribution System Services (DSS), provides an additional compatible and stackable revenue opportunity for qualifying projects that can meet specific distribution system needs identified through utility planning. DSS contracts compensate DER projects for verified, location-and-time-specific distribution grid services. Targeted grid services obtained through the DSS contract could range from meeting forecasted electricity demand to providing congestion relief, investment deferral, voltage stability, or resilience services. Because DSS implementation depends on sufficient identification and valuation of distribution grid needs, Part 2 may be phased in as utility IGP and other planning processes mature.

5.1 Part 1: Standard Offer Block

The capped, open-enrollment tariff structure of the Standard Offer Block facilitates procurement through long-term contracts of delivered energy and RECs compliant with Maine’s RPS requirements (§3210 Class I and Class IA RECs).[40] The benefits achieved in Part 1 are twofold: (1) a portion of Standard Offer supply need is met with a defined volume of clean energy and RECs at rates fixed at contract execution; creating a long-term supply hedge; and (2) time-differentiated rates incentivize energy delivery during predetermined bulk-system peak demand windows. Performance windows can be informed by ISO-NE published coincident peak data, with rates structured to reward incremental delivery during periods of high system demand.

Contract Model

The Standard Offer Block contracts would specify baseline annual delivered MWh, minimum REC volumes, performance requirements, and other obligations. Where applicable, contracts may also establish minimum delivery requirements during designated seasonal peak periods. Projects receive predetermined compensation rates for measured energy, environmental attributes, and any other values provided to the grid. The block volumes, contracted and aggregated by utilities in annual procurements for new projects, build a supply price hedge for the Standard Offer rate by insulating an increasing portion of supply from short-term market trends. Project performance conditions help assure the effectiveness of Standard Offer Blocks and reduce risk to Standard Offer providers.

The Standard Offer Block contract reflects time-differentiated prices for energy, accounting for the varying benefits achieved by delivering low-cost, low-emitting energy during periods of high demand. Time-differentiated compensation provides an additional incentive for delivery during standardized or defined peak-performance windows.

[40] Maine RPS requirements described at Maine Statute M.R.S. 35-A §3210, https://www.mainelegislature.org/legis/statutes/35-a/title35-asec3210.html.

- **Note**: The project consultants seek input on how capacity should be treated and valued in the program. Should capacity be included in the Standard Offer Block and conveyed to the Block at ISO-NE Forward Capacity Market settlement price? Or available to be retained and monetized by projects? Are there other approaches to procuring and valuing capacity that DOER should consider?

Price Setting

The proposed tariff contains pricing for energy and environmental attributes that reflect transparent and measurable costs. Options identified for calculating and establishing Standard Offer Block prices may include one or more of the following:

- Economic analysis of avoided costs (e.g., Avoided Energy Supply Costs in New England (AESC) studies)
- An informational solicitation that surveys project development costs and market conditions, and is verified by third-party data
- A competitive solicitation that relies on submitted bids to establish and procure energy and RECs
- A modified version of the Standard Offer retail rate that only reflects the value of the energy and REC components

An avoided cost evaluation enables measurement and verification of realized ratepayer benefits by establishing a counterfactual that is used to value and confirm the project's contributions to the grid, which then flows through to the tariff price. The informational solicitation sets the tariff price by combining appraisals of project economics, historical and projected market conditions, and objective third-party data to generate a value and verify that the value aligns with existing and expected financial and economic trends. Alternatively, a competitive solicitation would establish each block's tariff rates at the clearing level set by submitted bids, executing contracts with projects that can clear the tariff rate. In this way, competitive solicitation both prices and allocates the block. A hybrid approach could use project cost or competitive information to establish compensation values; and then subsequently confirm that the resulting procurement satisfies the applicable ratepayer-benefit threshold using an avoided cost methodology.

Each solicitation approach would be intended to reflect both the immediate and long-term value of securing energy and REC supply hedges for Maine ratepayers. Under any price setting approach, annual enrollment caps would be sized so that each block satisfies the §3209-I ratepayer-benefit determination, and caps and rates would be re-derived and published before each block opens.

- **Note**: The project consultants seek stakeholder feedback on this element of the program design. What would be the benefits or drawbacks of a hybrid price-setting approach that combines elements of the above? What would be the benefits or drawbacks of an alternative price-setting approach not listed here?

The project consultants do not advise deconstructing and using a modified version of the Standard Offer retail rate to price the cost of energy and RECs because the timing of the Standard Offer rate and the long-term agreements do not align. The Standard Offer rate reflects the cost to provide electricity supply to customers for 12 months, while the alternative price-setting methods reflect the value to Maine ratepayers over a multi-year period.

Cost Allocation and Recovery

Part 1 costs—including project compensation and reasonable utility billing, settlement, and administrative costs—could be recovered either from Standard Offer customers or from all retail customers. Recovery from Standard Offer customers would align the costs with customers receiving the direct supply-price hedge. Broader recovery could be considered if it is determined that the portfolio's energy, REC, and price stability benefits extend to all retail customers.

Possible recovery methods include requiring suppliers to incorporate Standard Offer Block costs into bids submitted to the Standard Offer Bid Solicitation or reducing the load obligation that suppliers price in the Standard Offer procurement process and recovering program costs through a separate rider. Under the first method, suppliers would purchase the Standard Offer Block services and incorporate those costs in their bids submitted to MPUC. Under the second method, the Standard Offer procurement would reflect a reduced load obligation and program costs would be recovered through a cents-per-kWh amount that is calculated according to the cumulative Standard Offer Block cost apportioned between rate classes and divided by the supply volume delivered per rate class over the contracted period. Under this method, Standard Offer solicitation instructions would require bidders to price the residual load and RPS obligation net of the contracted Block, so the transferred energy and REC value is reflected in bids.

- **Note:** The project consultants seek feedback regarding whether to propose recovery of Standard Offer Block costs from either Standard Offer customers or all Maine retail customers. Considerations include cost-causation alignment and migration exposure: recovery limited to Standard Offer customers aligns costs with the customers receiving the hedge but shrinks the recovery base if customers migrate to competitive suppliers; all-customer recovery avoids that exposure but may warrant finding that the portfolio's benefits extend to all retail customers. Which recovery option would be preferable and why? Is there an alternative recovery option that is not reflected here that should be considered? What is the alternative and why?

Table 5-1. Values compensated in the Straw Proposal, Contract Part 1 (Standard Offer Block)

Energy	Calculation that uses avoided costs, an informational solicitation, a competitive solicitation, or some combination to determine tariff pricing. Products are bundled and integrated by suppliers in submitted Standard Offer bids or used to reduce Standard Offer load obligations (supply hedge).
Maine Class I/Class IA RECs	REC conveyance is a condition of settlement: certificates pass through the utility to the standard offer providers serving the associated load for §3210 compliance verified at payment

5.2 Part 2: Distribution System Services contract

A separate DSS contract can provide additional revenue to qualified projects that supply measurable support to local distribution system needs or help defer or avoid distribution infrastructure investment. Part 2 relies on utility planning processes to define the location, timing, magnitude, and value of distribution system needs suitable for DER solutions to achieve distribution system value. As utility IGPs become increasingly specific and sophisticated, DSS can be phased in after Part 1 implementation and made available to qualifying new projects or existing projects with a Part 1 Standard Offer Block contract through amended or expanded long-term agreements. The long-term agreement will define the services provided under Part 2 and establish accompanying performance stipulations for locational and temporal benefits.

Early-stage DSS can contribute to grid services and infrastructure deferrals through distribution-oriented service contracts. For example, electricity demand increases caused by extreme weather or realized load growth can be addressed by energy and reserve services that increase energy production, manage distribution peak loads, and defer network investments. More sophisticated distribution services enabled by ADMS could include real-time voltage management, reactive-power support, or automated peak-load management. ISO-NE ancillary services, including frequency regulation, would remain distinct bulk-system products unless separately coordinated and compensated.

Contract Model

The straw proposal DSS contract tariff is informed by utility IGPs and includes an inventory of distribution system needs suitable for DER solutions, reliability, and resiliency support. For each required grid service, the tariff identifies the location, magnitude, temporal requirement, deferred capital investment opportunity (as applicable), and in-service date, alongside an applicable rate. These details are reflected in contract parameters that describe project performance conditions, a deferral window, operational requirements, and other features necessary to provide grid services. Projects receive compensation for their grid contributions during location- and time-bound performance windows, which could include distribution system peak demand periods. Specific grid service definitions and performance requirements would be the subject of additional review, informed by IGP processes, and could be standardized in MPUC rules.

Price Setting

The value of the DSS component is designed to motivate project deployment and performance at grid locations in greatest need of support. It can be formulated using a methodology specific to the service, time, and location of the need. The DSS value, and resulting price, is calibrated to reflect the applicable grid requirements and can be set at $0/unit for projects that are installed at sites that do not have identified grid or infrastructure needs.

Cost Allocation and Recovery

Costs associated with DSS are applied to all ratepayers in the applicable utility territory, as the associated services are comparable to conventional costs recovered through utilities' delivery charge. Incorporating these costs into rate case proceedings enables MPUC to determine the ultimate cost allocation and recovery methods associated with this program part.

Table 5-2. Selection of values compensated in the Straw Proposal, Contract Part 2 (DSS)

Grid stability services	The specific services provided in support of grid stability (e.g., voltage management, reactive power, etc.) are valued and priced using future utility IGP results or independent studies.
Avoided or deferred distribution infrastructure investments	Price is established using utility IGP results and reflects avoided or deferred distribution capital expenses. A $0/unit contract is possible for projects deployed at grid locations without identified needs.
Distribution network peak management/load management	This service manages resources to support network utilization and substation constraints. Compensation, set according to utility IGP results, can reflect the project's impact on net load during a specific location and time. Importantly, a project can receive compensation for providing concurrent, distinct grid services, but it cannot be compensated twice for the same service.

Note: Grid service definitions and price determination would be subject to additional development and subsequent MPUC rulings, particularly for DSS under the Part 2 contract structure.

5.3 Key roles

In the straw proposal, long-term agreements and tariffs are the primary vehicles for defining roles and expectations for each participating stakeholder. Generally, electric utilities provide key information and neutral facilitation of contracts; project owners finance, build, and operate projects; and regulatory oversight ensures cost-effective implementation of the program.

Utilities

- Utilities, by way of their system planning processes, identify resource requirements, locational and temporal grid needs, and opportunities for infrastructure investment avoidance or deferrals. This information informs the grid services procured in the utility-developed tariff and their associated pricing and performance obligations.
- The utility also provides project interconnection, metering, and billing functions according to standard regulations and practices. This information flows to the Standard Offer Bid Solicitation for incorporation in supplier bids.
- Utilities are also counterparty to DER project owners through long-term agreements facilitated by the program.

Project owners

- Project owners site and build FTM DER projects according to the performance obligations and features described by the tariff. They develop and finance projects based upon the revenue opportunities published in the tariff and assured by the long-term agreement.
- Project owners and utilities coordinate interconnection and asset operation through the utility interconnection process and performance requirements articulated by the tariff and ensuing long-term agreement.

DOER

- DOER proposes a program design to MPUC that meets the net-benefits-to-ratepayers threshold set in 35-A M.R.S. §3209-I. Subject to MPUC approval and available resources, DOER can assist with program implementation and administration.

MPUC

- MPUC reviews this program design proposal and evaluates its ability to provide benefits to Maine ratepayers in excess of the program's costs. If MPUC finds the program can accomplish this objective, MPUC will issue a determination and establish rules to implement the proposal.
- MPUC provides oversight of the program and its implementation. This can include reviewing and approving key program parameters such as procured services and quantities, tariffs, long-term agreements between utilities and projects, compensation rates, cost allocation and recovery, and other critical inputs. In addition, MPUC can confirm that utility proposals for grid services procured through the tariff align with system planning processes and state goals and requirements.
- MPUC facilitates the Standard Offer Bid Solicitation in accordance with standard rules and regulations.[41] To effectuate the Standard Offer Block, MPUC can confirm that suppliers and utilities are effectively and efficiently integrating procured Standard Offer Block quantities into customer supply volumes.
- In reviewing and approving tariffs and long-term agreements, MPUC can ensure that financial security provisions are sufficient to protect ratepayers and reduce the risk associated with extended contract lengths.

5.4 Administrative implementation

Straw proposal administration would be subject to additional attention and rulemaking to conform with existing procedures and practical considerations. The following are suggested approaches to guide program implementation.

Project eligibility and enrollment. A tariff establishes project characteristics and requirements for executing a long-term agreement. These stipulations may include developer conditions, connection type, conformance to Maine's RPS-eligible technologies, metering and communication capabilities, and other technical and siting features required to safely connect and operate the project.

Project obligations. Performance requirements are dictated by the grid need being addressed by the project. These can be reflected in the tariff through predetermined operational schedules or dispatch windows, alongside protocols for unscheduled grid services. Compared to the Part 1 Standard Offer Block, locational and temporal benefits procured through the DSS contract require precisely defined obligations and enhanced functional capabilities.

Cost recovery for DER integration. System costs that are created by participating resources can be recovered by one or a combination of methods. Those include traditional cost recovery methods to allocate costs across customer classes through common cost allocation approaches. Alternatively, a portion of program and grid costs could be defrayed through an export

[41] Maine Public Utilities Commission, Chapter 301, https://www.maine.gov/mpuc/legislative/laws-rules.

charge paid by project owners, based on project size or energy output. The preferred method for allocating and recovering costs can be the subject of additional work and would be implemented by MPUC rulemaking.

Annual cycle. The program tariff, or applicable riders, are updated on an annual basis to reflect the results of the most recent price- and volume-setting calculation and planning reports. This includes refreshing compensation rates for projects, establishing the Standard Offer Block quantity, and altering, adding, or removing DSS needs. The process to update the tariff can occur prior to or coincide with MPUC's Standard Offer Bid Solicitation process.

Program evolution. The straw proposal is designed to unlock incremental ratepayer benefits by establishing a durable framework that uses existing capabilities to provide near-term development of low-cost clean energy and integrating advanced system needs and requirements in future program stages. This is accomplished by identifying and resolving increasingly specific grid needs through maturing utility system planning processes and project capabilities. The proposal is technology-agnostic, permitting eligible technologies to provide progressively sophisticated grid services and receive adequate compensation. Tariffs and agreements will evolve alongside the program and enable existing and new projects to provide grid services at the location and time they are most needed.

The project team expects that assets participating in initial program stages will be configured to maximize energy production and dispatch capabilities—distributed solar, for example, or another RPS-compliant renewable energy resource paired with an energy storage asset. Later program phases can reflect the operational and physical evolution of the electricity system, which may include dynamic flexible interconnections, real-time asset dispatch, DERMS integration, and other features that enable provision of more precise grid services.

5.5 Technical implementation

Connection, coordination, and settlement of new DERs require additional functions and procedures to be established. Potential approaches to some of these are described here.

Dispatch priority. In addition to performance requirements, executed agreements specify a priority dispatch order to account for instances where a project may be called upon to serve both Standard Offer requirements and distribution system needs. In most cases, the distribution need should be served first, resulting in possible reduction to metered energy output and Standard Offer Block revenue. Under appropriate circumstances, a project can be eligible for more than one payment for providing multiple, distinct grid services during a single event or period.

Settlement. Settlements are conducted according to program rules and reflect the measured impact a project has on the grid. Gauging resource exports and contributions to the grid requires a revenue-grade interval meter at the project site to accurately assess and compensate for performance according to the time intervals and obligations stipulated in the project agreement. Revenue from Standard Offer Service and delivery charges, collected from customers by utilities according to MPUC rules and regulations, is used to compensate for services provided by projects. Costs associated with the Standard Offer Block are collected and settled monthly. Initially, DSS may require a monthly settlement or an alternative settlement timeframe to ensure measurable grid services are delivered, but advanced program stages may enable sub-monthly or sub-day settlement.

Interconnection. Existing distribution system technical capabilities could allow static, flexible project interconnections with a limit on curtailment events. The interconnection agreement can establish procedures for curtailment events, which may include the use of scheduled or emergency energy export reductions. Evolving utility grid controls and systems, such as

ADMS, can facilitate dynamic interconnections in the future and unlock real-time asset responses to grid conditions. Flexible interconnection requirements should be coordinated with related MPUC proceedings and decisions.

Aggregation. DER aggregation can be conducted by the utility or third-party aggregators, and resources are dispatched based on performance requirements defined in project agreements. Future program layers can reflect maturing system capabilities that result in dynamic grid service opportunities such as those attainable through a DERMS system.

5.6 Program model in practice

This section presents two illustrative scenarios to demonstrate how the straw proposal could be applied to anticipated project types in Maine. Each example is based on a set of hypothetical prices and initial contract terms offered in 2028, for contracts beginning service in 2029. In addition, this section discusses the feasibility under the straw proposal of another set of project types, or whether they might require a separate program design.

Project scenarios

Year 0 (2028) - Tariff setting. For the 2028 procurement Block, the MPUC approves a price for energy delivered during seasonal peak hours and a lower price for energy delivered in other hours. These prices are based on an avoided cost estimate and a survey of project development costs, ISO-NE energy market data, and third-party data to determine the immediate and long-term value of avoided energy. Maine Class I and Class IA RECs will have a separate value.

In addition, a distribution infrastructure investment deferral component (Distribution System Services), denominated in $ per kW-year, is available for projects sited in constrained grid locations as identified by utility planning (e.g., IGP) results, depending on location. Resources can qualify for the additional revenue available via the DSS Part only if they can deliver according to specified operational requirements that reasonably contribute to avoidance or deferral of the identified grid investment need. Each of these rates and their performance requirements are published in the open enrollment tariff and are available to the first 100 MW of projects that execute an agreement in 2028.

Example A: Solar-plus-storage project

Year 0 (2028) - Contract execution. A 3 MW solar-plus-storage (4-hour system) project sited at a constrained distribution grid location secures a 20-year contract through the tariff. Through the Standard Offer Block, the project commits to providing Standard Offer customers with a specified volume of energy during peak periods, a volume of energy during other hours in the year and the Maine Class IA RECs associated with the delivered energy. Through the Distribution System Services part, the project also commits to being available to discharge energy during distribution grid needs windows, set according to distribution peak energy demand hours.

Contract Year 1 (2029) - 100% obligations met.

- Standard Offer Block: The project meets all of its performance obligations set forth in the contract, achieving 100% performance in on-peak energy dispatch windows, off-peak energy volume requirements, and Maine Class IA REC volume requirements. The project receives 100% of the compensation it is eligible for through the Standard Offer Block.
- Distribution System Services: The project also meets all DSS requirements established in the contract by dispatching the battery during 100% of the distribution system's peak hours throughout the year. As a result, the project receives 100% of the compensation for which it is eligible through the DSS component.

Contract Year 3 (2031) - Obligations partially met.

- Standard Offer Block: The project meets 75% of the performance obligations set forth in the contract. The project receives 75% of the compensation for which it is eligible through the Standard Offer Block.

- Distribution System Services: The project similarly meets 75% of DSS requirements established in the contract. As a result, the project receives 75% of the compensation for which it is eligible through the DSS component.

Contract Year 7 (2035) - Conflicting obligations.

- Standard Offer Block: The project encounters concurrent dispatch windows for the on-peak energy portion of the Standard Offer Block and for the distribution system peak energy component of the Distribution System Services. The contract instructs the project to prioritize meeting the DSS need, so the project does not meet the Standard Offer need in this instance. The project does not encounter this situation again and is able to meet 95% of overall performance obligations associated with the Standard Offer Block. As a result, the project receives 95% of the compensation for which it is eligible through the Standard Offer Block.
- Distribution System Services: The contract requires the project to serve distribution system needs when it encounters simultaneous dispatch windows for the Standard Offer Block and DSS. This circumstance occurs once in Year 7, and the project provides distribution grid support in accordance with the contract. As a result, the project meets 100% of overall DSS performance obligations for the year and receives 100% of the compensation for which it is eligible through the DSS Part.

Example B: Storage add-on to existing solar project

Year 0 (2028) - Contract execution. An existing 5 MW solar project is located near a constrained distribution grid segment, resulting in frequent curtailment of the solar output. The project secures a new 20-year contract through the tariff.[42] The project commits to providing Standard Offer customers with a specified volume of energy during peak periods, a volume of energy during other hours in the year and Maine Class IA RECs. Initially, the project is unable to commit to discharging during predetermined distribution grid needs windows, but installation of a 2.5MW, 4-hour energy storage system in Contract Year 3 enables a contract amendment for Distribution System Services.

Contract Year 1 (2029) – Obligations partially met.

- Standard Offer Block: As a result of regular curtailment requests from the utility, the project meets 65% of the performance obligations set forth in the contract and receives 65% of the compensation for which it is eligible through the Standard Offer Block.
- Distribution System Services: The contract does not include Distribution System Services; thus, the project does not receive compensation for this Part.

Contract Year 3 (2031) - 100% obligations met.

- Standard Offer Block: The project installs a battery and despite regular curtailment requests from the utility, is able to meet 100% of requirements for energy during peak periods, energy during other hours of the year, and Maine Class IA RECs. As a result, the project receives 100% of compensation for which it is eligible through the Standard Offer Block.
- Distribution System Services: The contract amendment requires the project to dispatch its new battery during distribution system energy peak periods. The project uses the battery to meet 100% of DSS requirements and receives 100% of compensation for which it is eligible through the DSS Part.

Contract Year 7 (2035) - Evolving distribution system needs.

- Standard Offer Block: The project meets 100% of Standard Offer Block performance obligations and receives 100% of compensation it is eligible for through the Standard Offer Block.

[42] Projects participating in this FTM program would be ineligible for participation in net energy billing.

- Distribution System Services: The utility implements enabling technology and updates the tariff to reflect a set of advanced distribution grid needs, including voltage support. The project elects to amend its agreement to provide voltage support in addition to the Standard Offer Block and the existing Distribution System Services. The project meets 80% of dispatch windows during distribution system peaks and 100% of system voltage needs commanded by the utility. As a result, the project receives 80% of the compensation it is eligible for through the distribution system peak energy DSS Part and 100% of the compensation it is eligible for through the voltage support DSS Part.

Other DER project types

In addition to the two scenarios described above, other DER project types may be useful to address Maine grid needs. Some of these could be supported by the straw proposal, while others may require the creation of a different program to address their circumstances, technology configurations, or project economics.

- **Standalone storage.** There are valuable use cases for distribution-connected storage sited at constrained locations on the distribution network. FTM battery storage, for example, can provide distribution capacity services, defer or avoid substation expansion, and related services. Storage can also be located on distribution feeders with high penetration of existing solar PV, to provide shaping between supply and demand profiles. Within straw proposal design, standalone storage likely relies primarily on DSS contracts informed by utility-identified needs. Eligibility for a compensated distribution service would likely not be conditioned on charging exclusively from an associated renewable generator, provided the resource satisfies applicable statutory, interconnection, metering, performance, and anti-double-compensation requirements.
- **Commercial rooftop solar.** Commercial rooftops, especially medium to large retail buildings, warehouses, and manufacturing facilities, can offer attractive locations for solar arrays. Projects at these locations could be constructed as FTM resources if metering and contracts configured them as such. Commercial rooftop projects could participate in the straw proposal approach, given compatible rooftop leasing arrangements and interconnection rules. Aggregation of multiple rooftops by a third-party developer could also support project economics under the straw proposal.

5.7 Opportunities for enhancement

As the operational and technical capabilities of Maine's utilities and the DER industry evolve, there may be opportunities to layer additional, measurable grid service procurements onto this program design. Advanced system functions and communication and dispatch capabilities can enable greater project integration, achieving a future state where resources are dynamically deployed in response to real-time system conditions. The straw proposal is designed to anticipate and incorporate this type of grid evolution: projects built in the early years of the program would primarily provide value through the Standard Offer Block, while projects built in future years can integrate additional services or expanded performance requirements through DSS components as Maine's utilities improve their own ability to integrate and manage an expanding portfolio of distributed resources.

One such layer could include planning-informed procurement of tranches of repetitive, scalable high-value grid services through a capped tariff. This would rely on advanced network and asset capabilities, with the utility identifying categories of grid needs and infrastructure deferrals that are widespread and ripe for a standardized DER solution. Replicable and scalable projects could be deployed in response to these findings through an expansive tariff structure. The total share of revenue from Standard Offer Block might become relatively reduced in this future state as the need and associated value of energy and environmental attributes could be less compared to a rise in value for distribution grid services.

6 QUESTIONS FOR PUBLIC INPUT

DOER welcomes written comments on any aspect of this draft report. While specific questions for stakeholder input are included below, commenters are encouraged to provide input on any matter relevant to the proposed program.

Written comments are due no later than September 11, 2026, and should be submitted by email to DOER@maine.gov. To facilitate review, commenters are requested to identify the report section and topic to which each comment pertains.

Standard Offer Block Questions:

1. Cost Allocation - The Standard Offer Block component of the straw proposal provides an increasing volume of clean energy that reduces Standard Offer supply obligations or can be incorporated directly into Standard Offer supply volumes. This approach could collect revenue from Standard Offer customers to pay FTM DER projects in the program, while price effects from the new projects would also be experienced by Standard Offer customers. Is this approach to cost allocation and provision of program benefits feasible within available Maine ratemaking structures?
2. Capacity – How should capacity be treated and valued in the program? Should capacity be included in the Standard Offer Block and conveyed to the Block at ISO-NE Forward Capacity Market settlement price? Or available to be retained and monetized by projects? Are there other approaches to procuring and valuing capacity that DOER should consider?
3. Cost Recovery - this straw proposal considers whether to recover Part 1. Standard Offer Block costs from either Standard Offer customers or all Maine ratepayers. Which recovery option should be chosen and why? Is there an alternative recovery option that is not reflected here that should be considered? What is the alternative and why?
4. Price Setting - Which of the price setting approaches mentioned above for Part 1: Standard Offer Block should be proposed? Should the final proposal propose a price-setting approach that combines elements of the above (e.g., hybrid approach)? Is there an alternative price setting approach not listed that should be considered? What is it and why?

Distribution System Service (DSS) Questions:

5. The DSS component of the straw proposal incorporates more advanced utility planning to inform locational values for future FTM DER development. What limitations exist that could hinder the implementation of DSS and how might they be mitigated or alleviated?
6. Based on the straw proposal, what additional cost allocation options or considerations should be accounted for? If participating DER projects should bear a portion of program costs, such as through an export charge on energy or capacity, how should those charges be set?
7. After reading the straw proposal, what are the primary requirements for implementation? For example, what technical or administrative dependencies do you identify, which should be addressed to make the straw proposal feasible?
8. What additional aspects of a FTM DER program should be considered?

7 NEXT STEPS

LD 1777 (Public Law 2025, Chapter 430), Section 14 requires DOER to submit the proposed program design to the Maine PUC by September 30, 2026, with the Commission acting under 35-A M.R.S. § 3209-I. Prior to that filing, the project team will evaluate the program approaches through both a benefit-cost analysis (BCA) and will conduct an Implementation Assessment. Together, these analyses will help identify which program models best satisfy statutory requirements, provide benefits to Maine ratepayers in excess of costs, and support the long-term development of a durable, value-based FTM DER market in Maine.

7.1 Benefit-cost analysis

The BCA is intended to identify whether and, as applicable, demonstrate how, a proposed program creates net benefits for Maine ratepayers, supporting DOER's submission and Maine PUC's review. The BCA will utilize the process and methods specified as national best practices in the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources and Avoided Energy Supply Costs in New England (AESC) and build on the BCA work previously done in Maine. The project team will evaluate each program through the three complementary cost-effectiveness tests:

1. **Utility Cost Test (UCT).** This test evaluates DERs as utility resources and measures whether they reduce system costs by providing services such as capacity, energy, transmission, and distribution benefits. The UCT is the test that will determine whether the program provides net benefits for Maine ratepayers. If multiple programs pass the UCT, the Maine Test and Societal Cost Test will be used to help prioritize which programs to implement.
2. **Maine Test**. This test limits consideration to utility system impacts and key societal benefits relevant to Maine, such as reductions in carbon dioxide (CO_2) and nitrogen oxide (NOx) emissions. It provides a broader statewide perspective than the UCT while remaining focused on benefits accruing within Maine.
3. **Societal Cost Test (SCT).** The SCT assesses whether the program will deliver net benefits to society, capturing broad benefits that extend beyond Maine ratepayers, including wider environmental, economic, and market impacts. It provides important context but is intended as a supplementary perspective rather than the primary determinant of compliance with statutory requirements.

7.2 Implementation assessment

While the BCA evaluates whether a program is expected to produce net benefits for Maine ratepayers, a positive economic result alone does not guarantee a successful program. The program design must also be implementable within Maine's regulatory, operational, and market environment. For this reason, the project team will evaluate the straw program proposal through a structured assessment, considering questions that include:

1. Can the program be launched within a reasonable timeframe?
2. Will the program be attractive to industry now and over the next fifteen to twenty years?
3. Will the program create technical challenges that could inhibit feasibility?
4. Will the program design receive the support needed for successful implementation?

The Implementation Assessment is not intended to determine whether a program is possible in an absolute sense. Rather, it compares program models relative to one another and determines which approaches offer the best combination of implementation readiness, market viability, technical practicality, and stakeholder support.

DOER is required to solicit public input and submit a proposed program design to the Commission by September 30, 2026. In developing that design, DOER must consider, among other factors, the marginal benefit to ratepayers of the time value and location of generation, a compensation model based on the value of distributed energy resources, and incentives for energy storage that provides benefits to ratepayers in the State. The Commission must act on the proposed design no later than 120 calendar days after receiving it. If the commission finds that the proposed program provides benefits to ratepayers in the State in excess of the costs to ratepayers, the Commission implements the program by rule.

APPENDIX A. GLOSSARY OF KEY ACRONYMS AND TERMS

ADMS – Advanced distribution management system

AESC – Avoided Energy Supply Costs

BCA – Benefit-cost analysis

BTM – Behind the meter

CMP – Central Maine Power; an investor-owned utility providing electricity to southern and central Maine.

DER – Distributed energy resource

DERMS – Distributed energy resource management system

DG – Distributed generation

DOER – Maine Department of Energy Resources.

DSS – Distribution system service

FERC – Federal Energy Regulatory Commission

FCM – Forward capacity market

Flexible interconnections – An interconnection arrangement that allows resources to connect under dynamic operating limits, supported by monitoring and automated controls that can modify resource operation when system constraints arise.

FTM – Front of the meter

IGP – Integrated grid plan

ISO-NE – Independent System Operator – New England; a regional transmission organization covering the six states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

LCOE – Levelized Cost of Energy

LD – Legislative Document

MPUC – Maine Public Utilities Commission

MRS – Maine Revised Statutes

MW – Megawatt

NEB – Net Energy Billing

NMISA – Northern Maine Independent System Administrator

NWA – Non-Wires Alternatives

OATT – Open Access Transmission Tariff

OPA – Maine Office of the Public Advocate

REC – Renewable energy certificate

Versant Power – An investor-owned utility providing electricity to eastern and northern Maine.