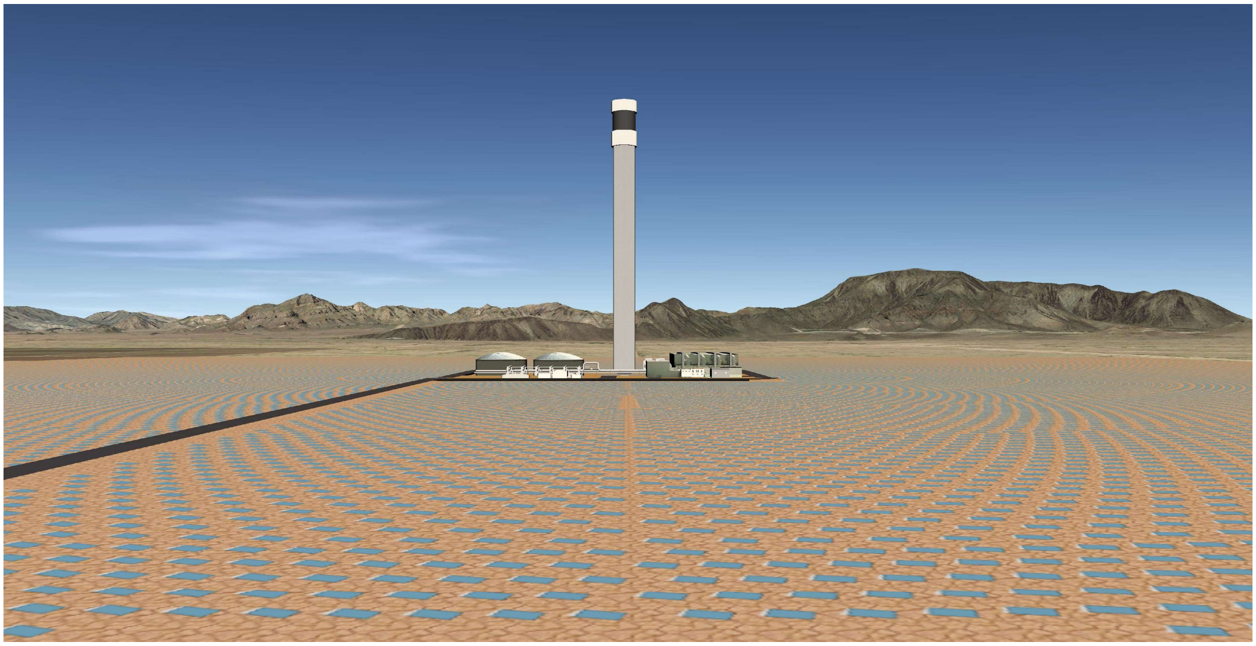
Final Technical Report (FTR)

Project Title:	**Dispatchable Solar Power Plant Project**
Project Period:	9/15/16 – 10/31/17
Submission Date:	01/31/2018
Recipient:	Solar Dynamics LLC
Address:	1105 W. 11th Ct. Broomfield, CO 80020
Website (if available)	www.SolarDynLLC.com
Award Number:	DE-EE0007579
Project Team:	Solar Dynamics LLC Sargent & Lundy LLC Morse Associates Inc. Kearney & Associates BluNebu LLC
Principal Investigator:	Hank Price, Managing Director Phone: 720-955-6404 Email: hank.price@solardynllc.com
Business Contact:	Hank Price, Managing Director Phone: 720-955-6404 Email: hank.price@solardynllc.com
Technology Manager:	Matthew Bauer
Project Officer:	Thomas Rueckert
Grant Specialist:	Edward Campbell
Contracting Officer:	Pamela V. Brodie



Artist's Rendering of a Dispatchable Solar Power Plant.

Acknowledgement:

"This material is based upon work supported by the Department of Energy's Office of Energy Efficiency and Renewable Energy Solar Energy Technologies Office."

Solar Dynamics would like to thank its partners for their contributions to this effort, especially: Bob Charles and Joe Hudziak from Sargent & Lundy, Dr. Fred Morse of MAI, Dr. David Kearney of KA Solar, Fred Redell of BluNebu, and John Costanzo. Solar Dynamics would also like to thank all the vendors, utilities, and developers that provided input and feedback to the project. Special thanks to Brad Albert at Arizona Public Service who was the inspiration behind the molten-salt tower peaker. Finally, thanks to Dr. Matthew Bauer for his support and guidance on the project.

Disclaimer:

Executive Summary:

As penetration of intermittent renewable power increases, grid operators must manage greater variability in the supply and demand on the grid. One result is that utilities are planning to build many new natural gas peaking power plants that provide added flexibility needed for grid management. This report discusses the development of a dispatchable solar power (DSP) plant that can be used in place of natural gas peakers. Specifically, a new molten-salt tower (MST) plant has been developed that is designed to allow much more flexible operation than typically considered in concentrating solar power plants. As a result, this plant can provide most of the capacity and ancillary benefits of a conventional natural gas peaker plant but without the carbon emissions. The DSP system presented was designed to meet the specific needs of the Arizona Public Service (APS) utility 2017 peaking capacity request for proposals (RFP). The goal of the effort was to design a MST peaker plant that had the operational capabilities required to meet the peaking requirements of the utility and be cost competitive with the natural gas alternative.

The effort also addresses many perceived barriers facing the commercial deployment of MST technology in the US today. These include MST project development issues such as permitting, avian impacts, visual impacts of tower CSP projects, project schedule, and water consumption.

The DSP plant design is based on considerable analyses using sophisticated solar system design tools and in-depth preliminary engineering design. The resulting DSP plant design uses a 250 MW steam power cycle, with solar field designed to fit on a square mile plot of land that has a design point thermal rating of 400 MW_t. The DSP plant has an annual capacity factor of about 16% tailored to deliver greater than 90% capacity during the critical Arizona summer afternoon peak. The table below compares the All-In energy cost and capacity payment of conventional combustion turbines to DSP plants. These results estimate that the cost of the DSP plant is about 10% higher than a similarly-sized and operated frame combustion turbine when APS reference fuel and emissions costs are included. The DSP plant cost is based on a single, first-of-a-kind plant, and it is likely that subsequent plants would be less expensive.

The table below shows the potential cost reduction viewed as possible with the DSP where additional learning and other approaches are used to lower the cost. The DSP plant represents an emission and carbon-free peaking power plant, free of future pricing risk. Moreover, it provides local jobs rather than importing fuel. As Arizona has excellent solar resources and lower construction costs than neighboring California, an in-state DSP facility offers Arizona the potential to export carbon free capacity and peaking generation to California to help address the complications inherent in the CAISO “Duck Curve”.

Case	**All-In Capacity Payment $/kW-yr**	**Levelized Cost of Energy $/MWh**
CT – Frame	$249	$189
CT - Aero Derivative	283	215
DSP – Baseline Cost (30% ITC)	**276**	**207**
DSP – Reduced Cost (30% ITC)	231	173
DSP – Power Park (30% ITC)	192	144
DSP – Power Park (10% ITC)	225	169

Table of Contents

List of Acronyms

ACC	Air cooled condenser
AGC	Automatic generator control
APS	Arizona Public Service
CAES	Compressed air energy storage
CAISO	California Independent System Operator
CEC	California Energy Commission
CF	Capacity factor
COG	Cost of generation
CSP	Concentrating solar power
CT	Combustion turbine
DCS	Distributed control system
DNI	Direct normal insolation
DOD	Department of Defense
DOE	Department of Energy
DSCR	Debt service coverage ratio
DSP	Dispatchable solar power
EPC	Engineering, procurement, construction
EPRI	Electric Power Research Institute
FAA	Federal Aviation Administration
FLG	Federal loan guarantee
FNTP	Full notice to proceed
FOAK	First of a kind
GE	General Electric
GW	Gigawatt
HE	Hour ending
HP	High pressure
IRP	Integrated resource plan
ITC	Investment tax credit
LADWP	Los Angeles Department of Water & Power
LNTP	Limited notice to proceed
LP	Low pressure
MS	Molten salt
MSCR	Molten salt central receiver
MST	Molten salt tower
MW	Megawatt
NREL	National Renewable Energy Laboratory
NVE	NV Energy
O&M	Operation and maintenance
OTC	Once through cooling
P&ID	Piping and instrument diagram
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PV	Photovoltaics
RFP	Request for proposals
RPS	Renewable portfolio standard
S&L	Sargent & Lundy
SAM	System Advisor Model
SCE	Southern California Electric
sCO_2	Supercritical carbon dioxide
SDG&E	San Diego Gas & Electric
SEGS	Solar Electric Generating System
SGS	Steam Generator System
SMUD	Sacramento Municipal District
SNL	Sandia National Laboratories
SRP	Salt River Project
STG	Steam turbine generator
TES	Thermal energy storage
TOD	Time of delivery
TSS	Thermal storage system
ZLD	Zero liquid discharge

1 Background:

Many factors are driving the growth in renewable power generation. In the United States, although federal policies such as production and investment tax credits substantially improve the economics, state policies have largely been responsible for progress in renewable generation. California, for example, has very aggressive carbon reduction goals that will have profound impacts on the conventional power marketplace throughout the entire western portion of the U.S. California's policies currently call for a 50% reduction in total carbon emissions by 2030 and an 80% reduction by 2050. This would require California to fully decarbonize its power sector to meet its 2050 goals for all sectors. This will require an unprecedented increase of renewable generation to achieve this goal.

Up until this point California has primarily focused on procurement of least-cost renewable energy and has not valued other attributes that can be provided by generators. As a result, California has added and continues to add large amounts of solar and wind generation, referred to as variable renewable generation power. To date all the solar generation added is either from photovoltaic (PV) or concentrating solar power (CSP) plants without energy storage. With an increased percentage of variable renewable generation as a fraction of total electric supply, maintaining a stable electric grid such that energy supply is matched to meet energy demand at every point in time becomes more challenging. Figure 1 shows an example of what is referred to as the CAISO Duck Curve. CAISO is the California Independent System Operator that manages electric supply for about 80% of the power consumers on the California grid. This Figure highlights the impact of daytime solar generation on the overall system supply requirement at current and future levels of renewable generation, showing an example of the net generation that grid operator must supply on a mild spring day after accounting for generation coming from solar and wind generation. The increase in solar generation solar generation in future years has two primary impacts on the management of the net supply. Note that it is significantly reducing the minimum daily net system load around noon and also resulting in steeper load ramps. These system characteristics require that baseload power plants be shut down and replaced with more flexible generation that can be ramped up and down to meet the changing system load. This is an inefficient situation, as many of the plants required to meet the evening ramp must be kept online through the minimum load point at part load during the middle of the day to be ready to meet the evening ramp, thus further reducing the head room for more efficient baseload generation. It is important to note that the Duck Curve results after California achieves its current goal of 33% renewable generation by 2020. As California moves towards its future goals of 50% and 80% carbon

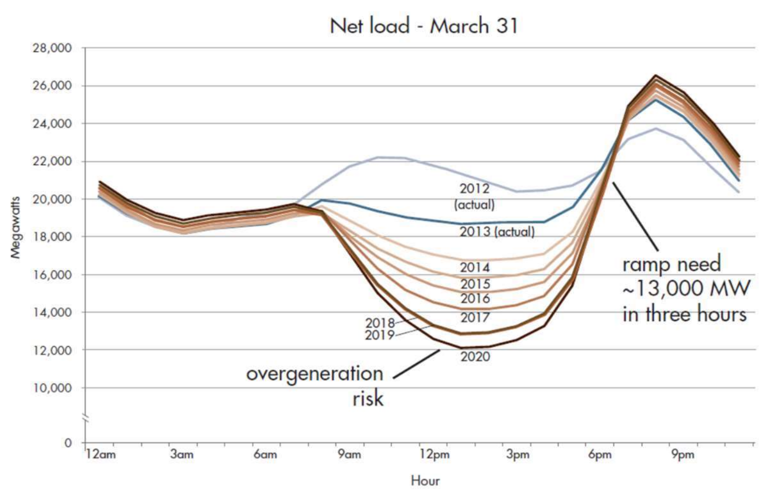


Figure 1. CAISO Duck Curve

reduction, the problem with managing supply and demand will become even more problematic for system operators.

PV prices have come down so much in recent years that CSP technology can no longer compete directly with PV on a simple levelized cost of energy basis. Studies by NREL have shown that CSP plants with thermal energy storage (TES) can have higher value than PV alone because they have thermal energy storage that allows them to be dispatchable and receive capacity value [1]. Molten-salt tower (MST) technology with its direct molten-salt storage is particularly well suited to provide dispatchable power. Historically, MST plants have been designed with large amounts of TES and large solar multiples such that the plants can be used to provide intermediate or even baseload power. But because of their dispatchability, MST plants could also be designed to be operationally flexible peaking plants to address the Duck Curve issue.

MST plants concentrate sunlight and as a result are typically only cost effective in sunny desert climates like the U.S. Southwest. This region currently has an excess of baseload generating capacity and does not need new baseload power plants. However, it also has large amounts of variable resource generation causing increasing intermittency on the grid, requiring the need for flexible peaking power plants. This project looks at the suitability and economics of a MST solar power plant that has been designed to be a dispatchable solar power (DSP) plant. The key questions are:

- Can the DSP plant supply the needed operational flexibility required?
- Is it economically attractive compared to the fossil or other alternatives?
- How would a DSP project be contractually and financially structured?

The NREL study [1] evaluated the operational and capacity value of a range of CSP plants with different solar multiples (1.3 to 2.7) [2] and TES capacities (0 to 15 hr) compared to PV in the California market for 33% and 40% RPS targets. The study found that at a 40% RPS target, the smallest CSP plant (a solar multiple of 1.3) evaluated with 6 hours of TES had the highest combined operational and capacity value ($96 – $109/MWh). This compared with PV that had a combined energy and capacity value of only $32 – $47/MWh. The results must be viewed in perspective as they only represent the relative value for a single year. The NREL analysis looked at a limited number of CSP plant configurations and the best value was the plant with the smallest solar field with the most storage, with a plant with half as much storage having only had a slightly lower value. Thus, it is not clear if the increased value of 6 hours of TES is worth the cost of doubling the storage size. The question remains as to whether the relative value of a CSP plant with TES continues to increase for plants with solar multiples below 1.3. In support of this study issue, DOE funded NREL to relook at this analysis and extend it for plants with solar multiples down to 0.5. Figure 2 shows the results from the extended NREL analysis. Details of this analysis are included in Appendix A of this report.

---

1 J. Jorgenson, P. Denholm, and M. Mehos, "Estimating the Value of Utility-Scale Solar Technologies in California Under a 40% Renewable Portfolio Standard", NREL/TP-6A20-61685, May 2014.

2 Solar multiple is a relative comparison between the thermal rating of the solar field compared to the size of the power cycle. A solar multiple of 2.0 means that at design conditions, the solar field can deliver twice the thermal energy needed to operate the power cycle at design output.

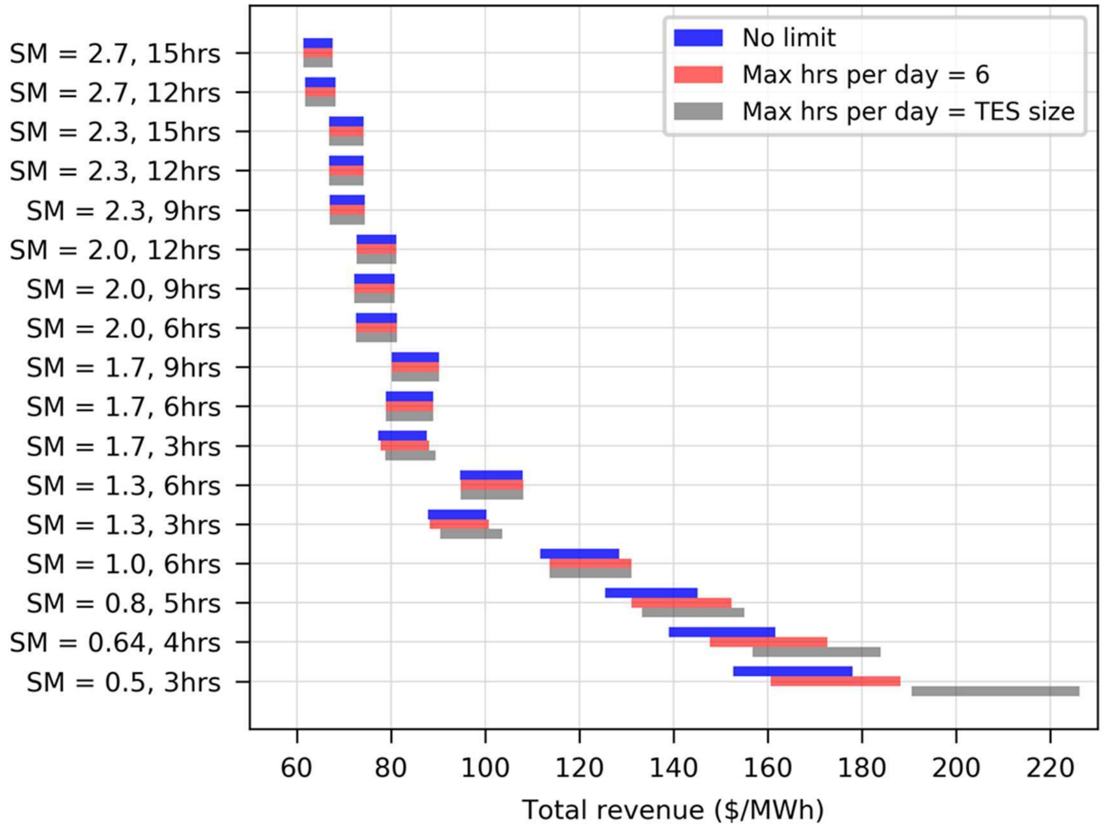


Figure 2 Total revenue including capacity value based on 100 highest net load hours

Notes: *1) Bar color corresponds to the maximum number of hours per day included in the capacity calculation. The grey bar limits the capacity calculation to the number of hours of TES in the plant. A plant with 3 hours of TES would only consider up to 3 hours per day in the capacity calculation.*
2) The range (length of the bar) corresponds to capacity cost of $150/kW-yr - $190/kW-yr).

The extended evaluation shows that the combined operational and capacity value continues to increase as the solar multiple decreases. The NREL analysis stops at a solar multiple (SM) of 0.5. At this point the plant is only operating at an annual capacity factor of about 12%, that is, only about 2 or 3 hours per day. Determining the capacity credit that a plant deserves requires a complex loss of load probability calculation. This was not possible with the data available to NREL, so they use a calculation of the percent of top 100 load hours served by the plant. A plant able to generate power during all the top 100 load hours receives full capacity credit. This becomes an issue for a plant that can only generate 2 or 3 hours of electricity in a day, since 9 of the top 100 load hours occur in a single day. NREL ran two additional cases: one where they limited the capacity calculation analysis to a maximum of 6 peak hours per day and a second where the maximum hours per day was the same as the number of hours of TES included in the plant. These two limits help the plants with smaller solar multiples achieve higher overall capacity value. Using the latter assumption, the total operational and capacity value of the plant with a SM of 0.5 increases up to $225/MWh. The NREL results highlight that CSP plants with small solar multiples can achieve high capacity benefit and produce high value electricity, and therefore strongly suggesting that an appropriately designed CSP plant could be used as a peaking power plant.

2 Project Objectives:

This project developed the conceptual design of a molten-salt tower (MST) dispatchable solar power (DSP) plant that has been optimized to compete with natural gas peaker plants, both in terms of operating requirements and cost. This project focused on three primary objectives:

Goal 1 - Technical: Develop a MST plant design that will meet the operational and performance requirements to work as a dispatchable generator in place of a fossil power plant. To accomplish this, the DSP plant must be designed to operate in a more flexible manner than is typically contemplated for MST plants.

Goal 2 – Cost Reduction: It will be necessary for the MST plant to compete against conventional fossil power plant on an economic basis. It is estimated that a 20 to 30% cost reduction will be required for the DSP plant to be competitive once the 30% ITC is reduced to 10% or eliminated. Five potential pathways have been identified to reduce the cost of MST peakers:

- using a new low-cost heliostat design,
- reducing the EPC schedule to 24 months or less,
- develop a standard plant design,
- build plants in power park configuration and,
- in the future, use an advanced super-critical carbon dioxide (sCO_2) power cycle.

Goal 3 - Commercialization: Develop a detailed conceptual engineering design specification that will demonstrate the technical feasibility of the DSP design and that is ready for the next stage of commercial project development. Identify vendors of all key equipment that can provide equipment that meets the operational requirements of the plant and that can provide performance guaranties to allow a conventional EPC company to wrap the overall performance of the plant. This project has developed a conceptual engineering, procurement, and construction schedule to deploy a commercial project with an EPC schedule approaching 24-months. Additionally, the design of the plant has been adapted to address some of the key siting/permitting issues that adversely affect public perception of tower projects.

Project Work Package:

Task 1: DSP Design Baseline (Months 1 – 3)

This task focused on defining the needs and requirements of the DSP Plant. A detailed review of the power markets in the southwestern U.S. was conducted to evaluate the market potential. An initial baseline design for a molten salt tower plant was developed using existing design and cost models. The design was optimized for a peaking application based on inputs our assumed initial operational requirements. An initial economic evaluation was developed to allow a comparison between the DSP and a fossil peaker.

Task 2: DSP Design Optimization (Months 4 – 6)

This task initiated work by a 3rd party power engineering design firm to review the DSP plant operational requirements, identify vendors for all the key equipment, confirm operational capabilities of equipment, and help optimize the DSP conceptual plant design. This led to a preliminary design specification that was used for developing a more detailed conceptual design in the next stage. The task concluded with an engineering design review that confirmed the feasibility of the DSP plant design for the next stage.

Task 3: Conceptual Engineering of DSP Plant Design (Months 7 – 9)

The 3rd party engineering firm initiated work on the full conceptual engineering package for the DSP plant. The engineering package included plant engineering layouts, equipment specifications and other engineering documents based on operational requirements, previous design specifications and results of the design sensitivity analysis. A preliminary class 3 EPC cost estimate and an initial level 1 EPC schedule were developed based on feedback from key vendors. An effort was made to compress the overall EPC schedule and onsite construction as much as possible. A detailed O&M cost model was developed specifically for the requirements of the DSP plant. Updated performance modeling was conducted based on vendor provided data. During this task the APS 2017 Peaking Capacity RFP was released. The decision was made to use the RFP requirements as the operational requirements of the DSP plant design. The task concluded with a Design Review of the draft conceptual design package generated by the 3rd party engineering firm.

Task 4: Commercial Development Plan (Months 10 – 12)

This task refined the DSP conceptual design engineering based on the updated design requirements and re-optimization of the plant design. Also, more detailed engineering designs and specifications were prepared allowing improvements in the cost projection. Finally, the task finalized the cost and finance models with inputs from the 3rd party engineering firm including EPC and O&M cost estimates, a compressed more detailed level 2 EPC schedule, and a project financial model. At this point, the conceptual design is fully documented and ready to proceed to next stage of plant design and engineering for implementation into commercial projects. During the task, the DSP concept was presented to many utilities, developers, financial institutions, and other stakeholders to get feedback on the DSP concept, market potential and potential interest in the concept.

3 Project Results and Discussion:

3.1 Market Assessment

Figure 3 shows the direct normal solar resource for the US with an overlay of the 3 main transmission system interconnections. CSP plants require a high direct normal solar resource which primarily corresponds to the Southwestern deserts. Accordingly, the market assessment for DSP plants focuses on the six southwestern states and Texas.

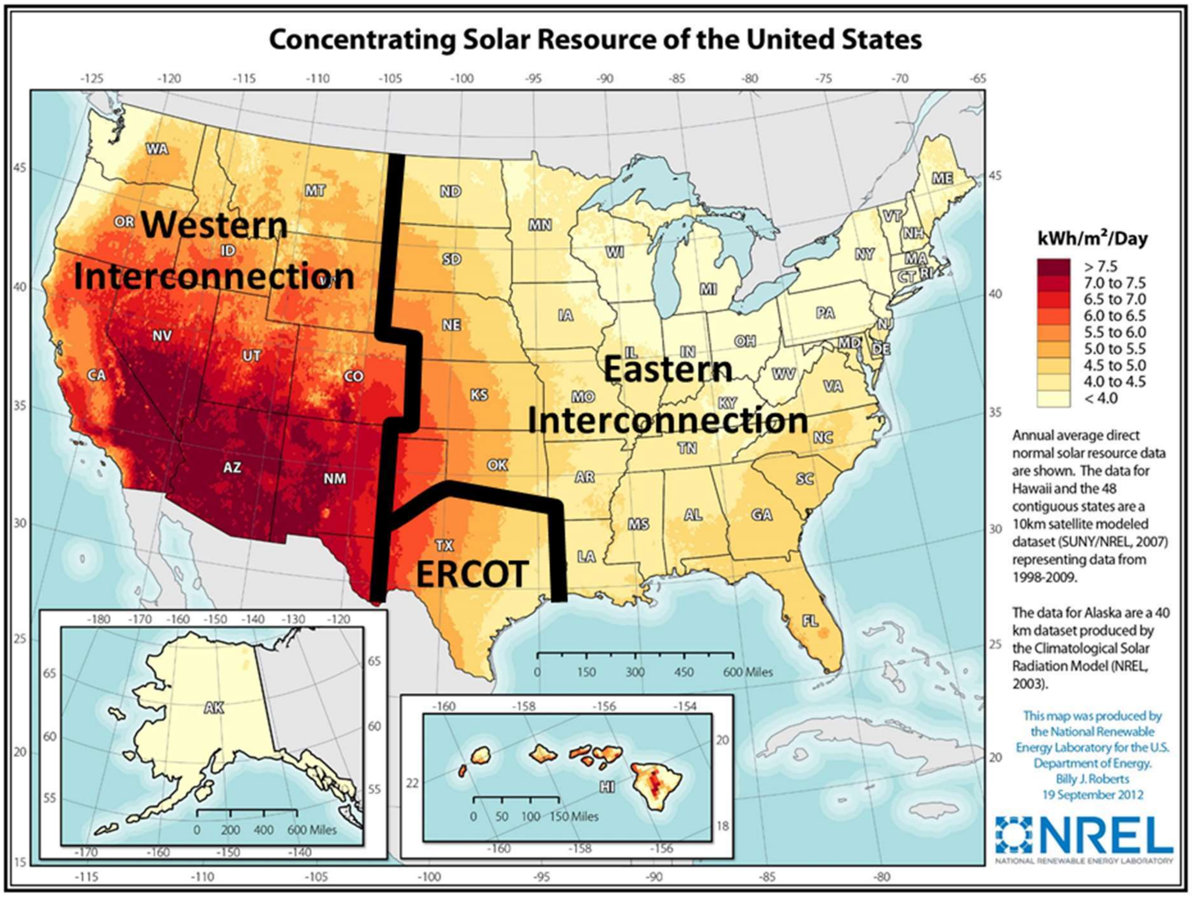


Figure 3 U.S. Direct Normal Insolation (DNI) Resource Map and Transmission Interconnections

Power markets are evolving rapidly away from the traditional regulated vertically integrated utility model. California represents over 50% of the population in the Western Interconnection, and thus energy policies in California have a major influence on this region. California policies focus on decarbonization of the power sector, decentralization of power generation, and regionalization. Decarbonization is achieved by moving to low cost wind and solar generation to replace natural gas generation and working to electrify transportation and buildings sectors. Decentralization of power supply comes about with distributed PV and other distributed resources. Regionalization of power sources results through sharing resources across the western U.S. to reduce the number of power plants needed in each state, saving money and emissions. These collaborations improve reliability, drive down costs and minimize transmission needs.

Here are the trends that the California Independent System Operator believes will affect the power market of the future [3].

1. Electricity will be used far more efficiently
2. Gas-fired generation declines significantly as the grid is modernized
3. The system load is shaped by the variable output of wind and solar resources
4. Demand becomes as important as supply in balancing the system
5. Electric service is increasingly decentralized
6. Regional collaboration supports efficient grid operations
7. Transportation and building energy use is integrated with electric service
8. New approaches enable everyone to contribute to and benefit from the transition away from fossil fuels.

These trends identify the factors that will likely drive the need for CSP plants in the future. These trends seem to support the need for more flexible CSP plants like DSP. This rest of this section looks at the potential markets for DSP plants both domestically and internationally.

California

California represents the best long-term potential for DSP plants. Although there is currently an excess of generating capacity, California's carbon reduction and once through cooling (OTC) policies will result in the need for significant addition of new generating capacity over the next 30 years.

- California has about 15 GW of OTC plants that need to be replaced. California utilities initially planned to replace many of the OTC plants with new natural gas plants. The CPUC recently un-approved a gas plant that was intended to replace a OTC plant to determine if a utility scale battery project would be a better option.
- California's carbon policy could lead to the virtual elimination of all fossil fueled generation not using carbon capture technology by 2045 or 2050.

The California market is broken into two groups, the large investor owned utilities (PG&E, SCE, and SDG&E) that are controlled by the CAISO, and the smaller municipal utilities (LADWP, SMUD, and several small city municipal utilities).

<u>CAISO (PG&E, SCE, SDG&E)</u>: CAISO supplies approximately 80% of the power in California and will need to replace approximately 14 GW of generation over the next 10 years due to replacement of once-through cooling plants and other retiring facilities. Additionally, CAISO expects to reduce its net load by 7.6 GW over the same period by using energy efficiency. Utilities will be required to increase RPS levels from 33% in 2020 to 50% in 2030. The OTC plants are close to load centers and provide local area capacity. CSP plants are typically located further away from load centers and are not a likely candidate to provide local area capacity. PG&E and SCE will have the most interest in DSP projects to support summer peaking located in the California central valley. Alternatively, capacity along existing transmission corridors in Arizona or Nevada might be of interest. SDG&E should consider DSP plants located in the

[3] Electricity 2030 – Trends and Tasks for the Coming Years, California ISO, October 2017. http://www.caiso.com/Documents/Electricity2030-TrendsandTasksfortheComingYears.pdf

Imperial Valley. These plants could also deliver power to SCE and LADWP. It is not clear at this time how CAISO would procure power from a DSP project.

California Municipal Utilities (LADWP, SMUD): Los Angeles Department of Water and Power (LADWP) supplies approximately 10% of California's power. LADWP is driven by the same California policies affecting CAISO. LADWP currently gets a significant amount of coal-generated power from the Intermountain Power Project (IPP), which is planning to repower with natural gas generation in 2024. LADWP needs approximately 2 GW of new generation over the next 20 years that will include: energy efficiency, distributed resouces, storage and new renewables. This is in addition to replacing 1 GW at IPP and 3 GW of in basin-thermal OTC projects. The Sacramento Municipal Utility District (SMUD) represents the next largest municipal utility in California. It potentially could be interested in a DSP-type plant located in the CA central valley to support summer peaking. Many of the municipal utilities in CA collaborate on power plants and transmission lines. It is possible that LADWP could be the leading off-taker on a joint DSP project with other municipal utilities in CA.

Arizona

Arizona is connected to California's grid and as a result the Arizona grid is significantly influenced by California's energy supply and demands. Historically, a fair amount of California's power supply comes from power plants in Arizona. Although this continues to be true, California has been shifting away from coal power to natural gas and renewable power. Because of this and other factors, Arizona is closing many of its coal power plants and looking to replace them with more flexible generating resources. During the early 2000s, many merchant natural gas plants were built in Arizona. Many of these plants have been underutilized in recent years and are some of the first to be used to replace capacity from older coal plants being shut down. But many of these plants were designed to operate as baseload and are not particularly operationally flexible.

Arizona Public Service (APS): APS's 2017 IRP calls for approximately 4 GW of new capacity over the next 15 years. APS has addressed about 1 GW of new capacity through upgrades to one of its existing plants and through its 2016 All-source RFP where it procured 550 MW of idle merchant power. It has currently issued a 700 MW peaking capacity RFP, with proposals due in July, for projects to begin supplying power in the summer of 2021. APS is expected to have additional RFPs will similar levels of capacity requested for the next several years.

The 2017 RFP is ideally suited for a DSP project operating under a solar tolling agreement PPA. Consequently, Solar Dynamics has used the APS 2017 Peaking Capacity RFP as an important reference for developing the design, operational, commercial, and financial requirements of a DSP project.

APS's 2017 IRP shows that it will double its natural gas use over the next 15 years. As a result, it will likely need to increase its natural gas pipeline supply infrastructure. However, the installation of DSP plants in Arizona can reduce the need for new natural gas pipeline capacity and or gas storage capacity. In the value analysis of the DSP, we include the avoided cost of natural gas infrastructure. Cost uses were based on estimates provided by APS.

Salt River Project (SRP): SRP is in the process of closing its older coal generation facilities and replacing them with more flexible natural gas plants. In recent years, SRP has indicated about 1

GW of new peaking capacity would be required in the next 5-8 years or so, which would create an opportunity for DSP plants.

Nevada

A primary reason for DSP plants to be built in Nevada would be to sell power into California. However, in May the Nevada Assembly passed AB 206, which would accelerate the state's current RPS mandate to 80% renewable energy sources by 2040, with an interim goal of 50% by 2030. The current RPS sits at 25% by 2025. This opens new opportunities for DSP in this state.

NV Energy (NVE): NVE is the main utility in southern Nevada, providing power to Las Vegas. The Crescent Dunes molten-salt tower plant is located in Nevada and sells power to NVE. NVE has already phased out much of its coal generation and has switched most of its generation to natural gas. Unfortunately, NVE has very weak demand and is struggling to keep its current customers. As a result, NVE is not expecting the need for new capacity. However, there is growing interest by customers and the state to increase renewable generation. Much of the gas generation is likely to be base load generation. More flexible peaking capacity may be needed in the future as the RPS kicks in. This growth could increase demand of more conventional CSP plants.

New Mexico

New Mexico has excellent sites for CSP but has relatively low peak demand and abundant wind, natural gas, and coal generation. Without RPS requirements, it is unlikely to be a significant market for CSP.

Colorado

Colorado has abundant low-cost wind power. Solar is a small part of its renewable portfolio and does not seem to have Duck-Curve issues at this point. Coal is being replaced by natural gas to increase operational flexibility. The San Luis Valley has the best DNI solar resource in the state but has limited transmission access and very cold winters. However, newer NREL solar data seems to indicate that some areas in the eastern plains near Pueblo could be reasonable solar resource sites and have much better access to transmission.

Texas

Western Texas has good solar resource sites in the west but does not have good transmission access to the population in central and eastern Texas. Texas does not have a capacity market that offers long-term contracts, thus making it difficult to finance a DSP project in Texas. However, the municipal utilities in Austin and San Antonio could be potential customers for long-term contracts.

Utah

Utah has moderate CSP resource sites. There could be potential to transport power from Arizona into Utah (PacifiCorp has a transmission line from the Cholla coal plant in AZ). At present, however, PacifiCorp has weak demand for new capacity.

International Markets for DSP

There are a number of international markets in which CSP is being deployed where the DSP plant could be an attractive option. International markets often have demand and associated TOD structures that favor nighttime generation, and thus should be considered for future analysis. Most attractive international markets in terms of current activity include (alphabetically)

- Australia
- Chile
- China
- Middle East (e.g., UAE, Saudi Arabia)
- Morocco and other North Africa countries
- South Africa

Market Summary

- APS represents a near-term market opportunity for solar peaking capacity.
- California in general represents a huge opportunity for future CSP expansion due the carbon policies in the state. The CSP industry needs to develop a strategy to market flexible CSP plants for California. Outreach to key Stakeholders in California is needed (California PUC, California Energy Commission, California Air Resources Board, CAISO, state government, major utilities).
- As other states like Nevada and New Mexico increase their RPS requirements, those state could be good opportunities for flexible CSP plants.
- The international market for CSP is relatively strong and driving costs down. This provides an opportunity to assess if flexible CSP concepts could provide an attractive option for international markets in the future.

3.2 DSP Operational Requirements

The DSP plant is designed to meet the operational and performance requirements necessary to work as a dispatchable generator in place of a fossil power plant. During the initial stages of the project, the 2016 Arizona Public Service (APS) "All Source" request for proposals (RFP) was used to define the initial operational and performance requirements for the DSP plant. About midway through the project, APS released its 2017 Peaking Capacity RFP. The 2017 RFP included options for conventional fossil peaking resources, energy storage, and renewable resources with energy storage. The 2017 RFP included very specific design, operational and performance requirements depending on the technology. The fossil and energy storage technologies were to use a tolling power purchase agreement contractual structure for this project.

Power Purchase Agreement: Renewable resources with energy storage technologies were to use a more conventional energy-based power purchase agreement contractual structure with time of delivery (TOD) multipliers. Figure 4 shows the TOD periods and pricing requirements.

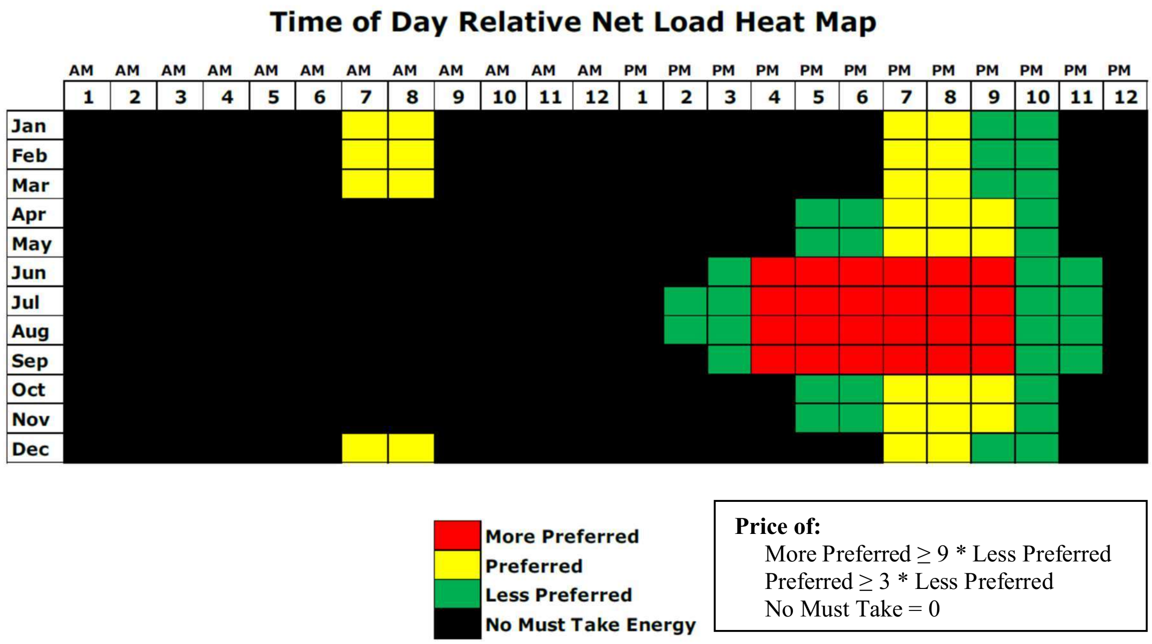


Figure 4 Appendix A from APS 2017 Peaking Capacity Request for Proposal (RFP)

APS is primarily interested in power supplied from Hour Ending (HE) 4 to HE 9 during the summer months of June to September, labeled as “More Preferred” on the chart. In direct discussions with APS, they are most interested in power (capacity) produced during July and August. Because renewable resources generally collect energy daily, APS has also defined the “Preferred” hours, during non-summer months, when they have the highest demand for additional energy. It is worth noting they have two “Preferred” delivery periods during winter months corresponding to their double-peak net load during the winter. APS also has a morning heating load and an evening heating and lighting/TV load. The “Less Preferred” hours represent periods when they don’t really need additional power but will accept it. APS will not accept power during the “No Must Take Energy” hours.

<u>Tolling Agreement</u>: The 2017 APS Peaking Capacity RFP included a Tolling PPA structure for fossil and energy storage plants (aka batteries, pumped hydro, CAES, etc.). In a Tolling PPA, the utility pays the power plant to stand by and be available to operate. When the utility wants to dispatch the plant to operate, it sends a signal to start up, controls the ramp rate (within plant specifications), and controls the load and duration of operation. The utility purchases the fuel for the plant and takes the fuel supply and pricing risk. In the case of energy storage facilities, the utility provides the electricity needed to charge the storage and determines when to charge the storage. The plant owner/operator is responsible for the availability, capacity, and efficiency of the plant. The plant pays penalties a) if it is not available to operate when called upon (or trips off-line), b) if the plant cannot achieve its rated capacity (net MW_e power output), or c) if the plant uses more fuel than the guaranteed efficiency. With a tolling PPA, the plant is usually paid a monthly capacity payment ($/kW-month), a variable O&M cost payment ($/MWh) and a payment for each start ($/start). With the capacity payment adjusted for availability, heat rate, and capacity.

Solar Tolling Agreement: Although not explicitly considered in the 2017 RFP, the concept of a solar tolling agreement was discussed as a possible approach with APS. A solar tolling agreement would work very similar to a conventional fossil tolling agreement. The main difference is that the daily fuel supply would be a function of the solar resource at the DSP plant site. The utility would decide how and when to use this fuel. The solar plant operator would be responsible for harvesting the solar fuel (conversion of the solar energy into thermal energy in storage) as well as the availability, capacity, and power conversion efficiency of the conventional power block. In a similar manner to a fossil polling agreement, the solar plant would pay penalties if it is not available to operate when called upon (or trips off-line); if the plant cannot achieve its rated capacity (net MW_e power output); or if the plant collects less thermal energy or converts it at a lower efficiency than guaranteed. Similar to a fossil tolling PPA, the plant would be paid a monthly capacity payment, a variable O&M cost payment, and a payment for each start. The capacity payment would again be adjusted for plant availability, heat rate, and capacity. With a solar tolling PPA, accurate forecasting of the solar resource becomes very important, as the utility will want to know how much "fuel" the solar plant will have available in order to determine the optimum dispatch of the solar plant combined with its other generating resources.

In general, a solar tolling agreement is more attractive to the utility than the more conventional PPA with TOD factors. With the PPA, the utility has no control or limited control over when the plant produces power. With the tolling agreement, the utility can decide exactly when and at what level the plant will operate. The utility can decide to store energy over night or even to dump energy if desired. As the system load changes over time, the utility can shift the operation profile of the plant to better meet its day-to-day needs. With a conventional PPA, the TOD factors are usually set for the term of the contract.

Given this evaluation, we will assume here that a DSP plant will operate under a solar tolling PPA structure.

Requirements for Solar Peaker: APS fossil peaker requirements are listed below with adjustments or corrections required for the DSP Plant.

APS New Build Thermal Generation Minimum Requirements:

- Transaction Structure: Tolling PPA (not more than 20 years).

  For the DSP plant it is desirable to increase the Tolling PPA term to 25 or 30 years if possible. The price will increase with the shorter 20-year Tolling PPA term and the utility loses the value of 10 years of solar fuel.

- Unit Contingent Toll: Product must be delivered as a unit contingent toll with no ability of the respondent to substitute product from another source and with APS supplying the fuel and related transportation service for delivery to the point of interconnection between the resource and the delivering pipeline(s).

  It is not an issue for the DSP to have the product (output) delivered as unit contingent toll. No gas supply is required. While the DSP plant as designed here is solar only, *DSP plants could be hybridized with natural gas backup. However, hybridization with natural gas did not look economically attractive or even necessary in Arizona.*

APS Technical Requirements:

- Capable of operating for 4 hours at 114°F and 20% RH at 100% contract capacity.

  The DSP plant can be designed to maintain full capacity at these conditions.

- Dispatchable by APS with automatic generator control (AGC) load following capability.

  The DSP control system can be designed to do this.

- Resource must be connected to either the El Paso or TransWestern interstate NG pipeline.

  Not required for DSP.

- Must have adequate water rights to support the full contract Peaking Capacity for the proposed term of the tolling PPA.

  No difference, except the DSP also needs water for mirror washing.

- Must have emission allowances.

  No emission allowances required for DSP.

- Any carbon allowances for the facility must be passed through to APS at no charge.

  No carbon allowances required for DSP.

APS Preferences:

- Prefer connection to both pipelines.

  Not required for DSP. Need to select a site with good summer solar resource.

- Resource is capable of stable operation at a minimum operating level of 25% loading and without exceeding emissions limits.

  DSP plants can operate stably at gross loads below 10%.

- Capable of at least 2 starts per day.

  This is not an issue for the DSP.

- Faster ramp rates are better.

  The DSP can ramp at 10% of rated output per minute once plant online and at operating temperature.

- Resources with shorter minimum run, minimum down, and start-up times better.

  The DSP has no minimum run or down times. Fast start steam turbine design allows DSP plant to be dispatched from idle to full load in 25 minutes.

- Resource capable of being online and dispatchable in 10 minutes or less (quick start).

  Fast start steam turbine design allows DSP plant to be dispatched from idle to full load in 25 minutes. Plant can be online in under 10 minutes and at 90% load in 18 minutes.

- Shorter term transactions are preferred assuming levelized price of product delivered over the duration range remains competitive.

APS Tolling Agreement Payment Structure:

- Monthly capacity charge ($/kW-month)
- Monthly variable O&M charge ($/MWh), and
- Start charge ($/start).

3.3 DSP Conceptual Design

Solar Dynamics engaged Sargent & Lundy to develop the conceptual design for the DSP molten-salt tower plant based on a preliminary design developed by Solar Dynamics. In this approach, Solar Dynamics is working as the developer and Sargent & Lundy as the design engineer for the project. With this approach, the development team defines the general parameters of the design that is best optimized to meet the requirements of the client or RFP. The engineer then develops the plant conceptual design in coordination with the development team, making sure the resulting design continues to meet the required design specifications. Solar Dynamics took an active role in the design optimization process especially in relation to the optimization of the solar systems (heliostat field size and layout, receiver size, and tower height). Sargent & Lundy took responsibility for the design of the power plant and integration of the plant design.

The MST DSP plant utilizes many features that are based on the current state-of-the-art for MST Plants. The solar side of the plant is largely a conventional molten-salt tower plant. The salt storage is a standard MST system, but likely oversized (relative to the solar field rating) compared to more traditional MST designs. The power cycle side of the plant is optimized for more flexible operation, faster starts, quicker ramping, improved availability, reliability of starts and operation, and the ability to maintain net output at elevated ambient temperatures.

Like the current MST design, power is generated by a multi-stage reheat steam turbine that receives superheated steam and reheated steam from a molten salt steam generator. The major differences between a conventional MST plant and the DSP plant are the plant control system and the need for the steam generator and steam turbine designs to accommodate rapid start-ups. “Fast-start” steam turbines for peaking service are available from turbine vendors. These turbines have been proven in the combined cycle applications and are suitable for use in a MST peaking facility. A coil-type evaporator design has been selected for steam generation. The coil-type evaporator design results in smaller material thickness and thereby lower thermal stresses. The operating capability of a coil-type evaporator is able to meet the steam demand of a fast-start steam turbine.

The Solar Collection Field and Thermal Storage System can operate independently from the electric generating systems. Components from a conventional MST plant (heliostats, tower receiver, and two-tank storage system) have been found to be congruent with the requirements of the MST Peaker Design. Like current MST plants, the HTF (molten salt) is pumped from the cold storage tank at 550 °F to the MST receiver, heated to a temperature of 1050 °F and transferred to the hot storage tank. For power generation the hot storage tank transfer pumps deliver the hot HTF to the steam generation system (SGS). Superheated steam is generated in the SGS and delivered to the steam turbine generator (STG). Cold HFT is returned from the SGS to the cold storage tank.

To improve site selection and permitting, the plant is designed to fit on a square mile parcel of land including fencing, right of ways, roads, etc. This is described in more detail in section 3.10. We assume the entire plant fits within the boundaries of the square mile facility except for laydown areas and other areas that may be required during construction. We further assume there are adjacent areas to the site for this. The O&M facilities (offices, warehouse and workshops) are not included in the square mile site. Evaporation ponds for waste water discharge may also be located outside the square mile.

It is necessary to have a real site identified in order to develop the design and an accurate cost estimate. We have selected a reference site, 1 mile by 1 mile in size, located in the Harquahala Valley in Arizona. The site has proximity and transmission line right of way access to an APS substation. There are multiple sites at this location that could be used for one or more DSP plants. This location can be used to supply power to either APS or CAISO substations. These sites have been screened for Department of Defense (DOD) and Federal Aviation Administration (FAA) height restrictions (see section 3.10). The sites are currently privately owned and farmed agricultural land. The sites would likely only require minimal civil works to prepare them for use. As the sites are relatively close to the I-10 interstate highway, there is good roadway access though the towers and receivers would be visible from the highway. The sites are largely screened from major population areas by mountains, which would help minimize visual impacts. The sites are close to the Phoenix metro area, providing access to skilled labor. Solar Dynamics visited the sites and confirmed they represent good sites for development of a MS tower project.

For the APS DSP Plant, the plant has been optimized to have produce 5 hours of generation reliably from 4pm to 9pm in the months of July and August. The resulting plant will only have an annual capacity factor of about 16% and has a solar multiple of approximately 0.66. APS has provided us guidance on the design of the plant and appear comfortable with the level of performance expected during their critical summer on-peak period which defines the capacity value of the plant. During the rest of the year, the plant needs to be flexible in its dispatch to allow APS to use the plant as a flexible resource to help optimize the rest of their generation resources. The thermal storage has been sized to allow generation during the non-summer months to be dispatched during non-daylight hours.

S&L has developed a detailed DSP design specification that draws from their commercial projects. It also relies heavily on the Nexant Molten Salt Tower Design Basis developed following the Solar Two project as a reference document for the design of the molten-salt systems in the plant. S&L updated the document with feedback from Solar Dynamics and with lessons learned from more recent molten-salt tower and trough plants, and with design requirements specific to the DSP plant.

Table 1 provides the final DSP plant design characteristics for the APS 2017 Peaking Capacity RFP.

Table 1 Design Characteristics of the MS Tower DSP Plant for APS

Design Characteristics	Value
Turbine Nominal Gross Power [$MW_{e,\ Gross}$]	250
Turbine Nominal Net Power [$MW_{e,\ Net}$]	230
Power cycle gross thermal efficiency [--]	44.0%
Power cycle cooling system	hybrid
Power cycle design ambient temp. [C]	44.8
Solar Receiver design duty [MW_t]	400
Solar Multiple [--]	0.70
Receiver Areas [m^2]	538
Receiver Height and Diameter [m x m]	12.23 x 14
Tower Optical Height [m]	168.5
Total Heliostat Area [m^2]	700,800
Heliostat Type	BS V 2.4
Heliostat Size [m^2]	20.8
Number of Heliostats	33,718
Solar Field Area [acres]	600
Storage Capacity [MWh_t]	3,000
Storage Capacity [hr]	5

3.3.1 Power Block Summary

The Power Block for the MST Peaker will be designed using proven technology. The Power Block is designed to generate 250 MW (gross). The major equipment consists of:

- Molten Salt Central Receiver
- Thermal Storage System
- Steam Generator System
- Steam Turbine Generator
- Hybrid Cooling System
- 230 kV Switchyard
- Balance of Plant.

The layout of the equipment in the power block area is shown in Figure 5. A rectangular power block area was selected over a circular area to allow more optimum arrangement of key equipment. The square power block area also improves the flux profile on the receiver because the square solar field has higher flux hitting the tower from the increased heliostat area in the direction of the corners in the solar field.

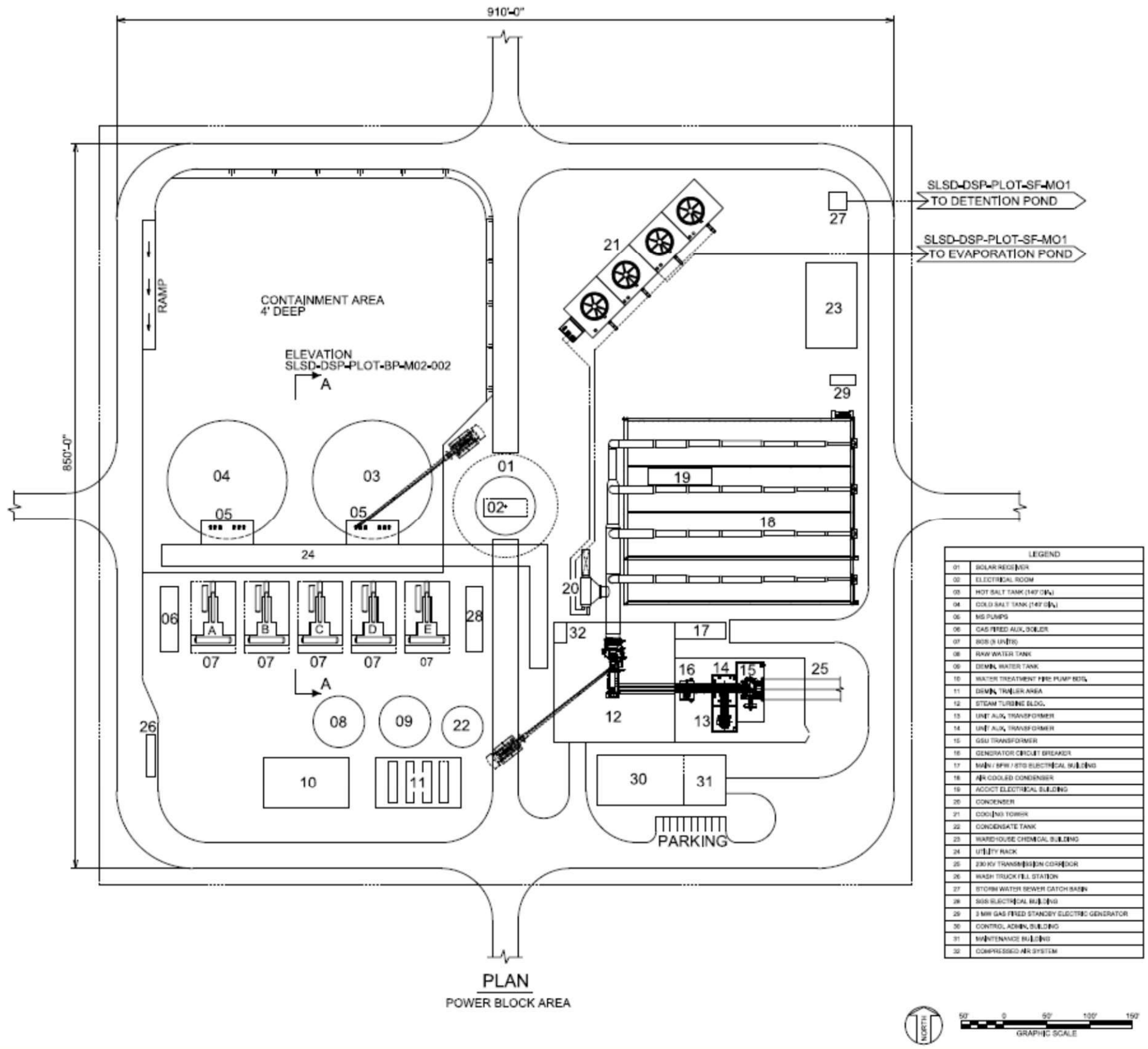


Figure 5 Power Block Layout (Sargent & Lundy)

01 Solar Receiver
02 Electrical Room
03 Hot Salt Tank
04 Cold Salt Tank
05 MS Pumps
06 Gas Fired Aux. Boiler
07 SGS (5 Units)
08 Raw Water Tank
09 Demin. Water Tank
10 Water Treatment Bld.
11 Demin. Trailer area
12 Steam Turbine Bld.
13 Unit Aux. Transformer
14 Unit Aux. Transformer
15 GSU Transformer
16 Generator Circuit Breaker
17 Main Electrical Building
18 Air Cooled Condenser
19 ACC/CT Electrical Bld.
20 Condenser
21 Cooling Tower
22 Condensate Tank
23 Warehouse Chem. Bld.
24 Utility Rack
25 230 kV Transmission
26 Wash Truck Fill Station
27 Storm Water Sewer Catch
28 SGS Electrical Building
29 Gas Fired Generator
30 Control Admin. Building
31 Maintenance Building
32 Compressed Air System

3.3.2 Solar Field

The solar field is designed to fit on a square mile section of land. The NREL SolarPilot model was used to optimize the layout. The power block and solar tower/receiver are located approximately at the center of the square mile solar field. The location of the tower has been optimized to minimize cost and maintain flux limits on the molten-salt receiver.

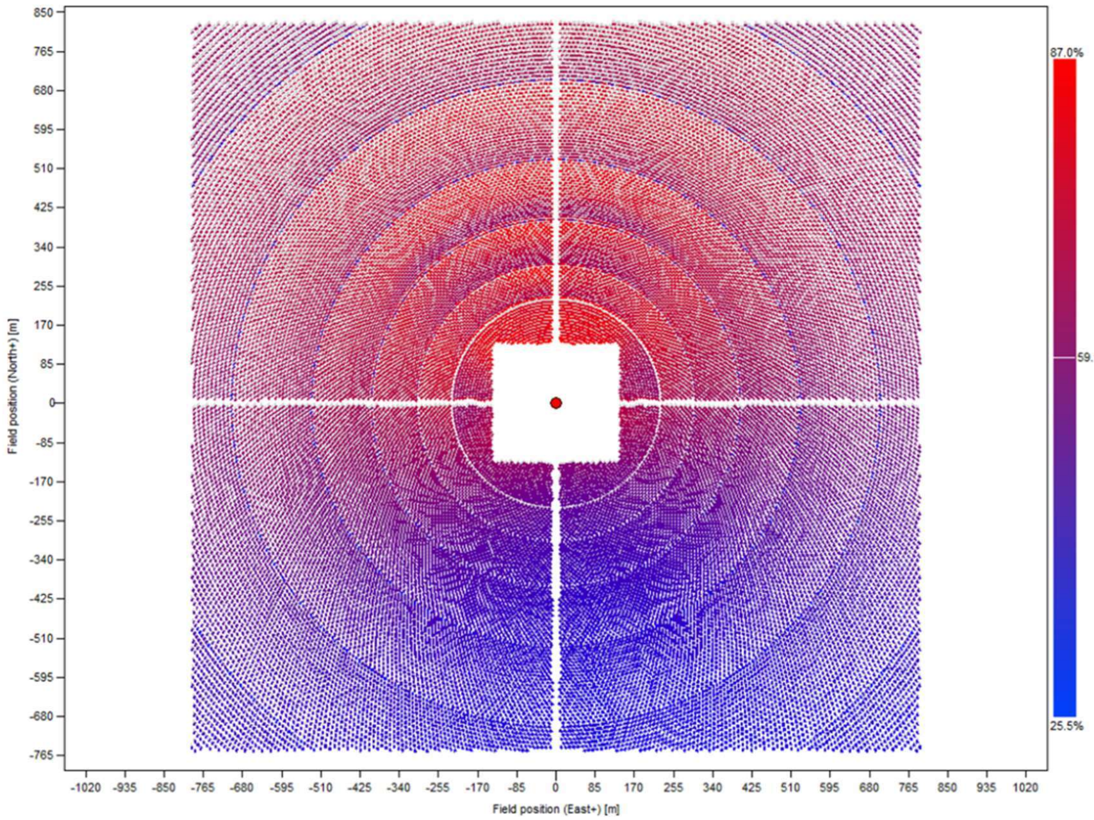


Figure 6 Proposed Square Mile Heliostat Field Layout (SolarPilot).

We assumed the BrightSource v2.4 heliostat as our reference design for the project. This is an autonomous heliostat design that is PV powered with battery backup, uses wireless communications, and has four mirror sections for a total area of 20.8 m^2. The solar field will consist of approximately 33,000 heliostats, each heliostat having a reflective area of 20.78 m^2. The total reflective area is approximately 700,000 m^2. This heliostat design has been commercially deployed at the BrightSource Ashalim tower project in Israel that is currently under construction.

The BrightSource version 2.4 heliostat design assumptions are:

- mirrors landscape 2m h x 2.6m w; 20.78 m^2
- 0.4 m clearance at the ground
- Mirrors flat
- Glass mirror 4mm thick
- Gaps between mirror panels very small: 4mm horizontal; 30 mm vertical
- Survival wind speed: 85 mph wind speed in stow
- Mirror Quality and Production: X < 1.5 mrad, Y < 1.0 mrad

3.3.3 Tower

Similar to other MST plants, the solar receiver is supported by a steel-reinforced concrete tower, utilizing slip form construction techniques. The subcontract for the tower will include the design of the concrete tower and foundation. Foundation design for the conceptual design is assumed to be spread footing. The subcontract will include the design, supply, transport and erect the secondary structures and accessory items, including external perimeter platform, access stair case and emergency ladder, permanent personnel elevator, supports for piping and cable trays, heat protection coating and aviation warning lights.

The tower height has been optimized to an optical midline height of approximately 168 meters using SolarPilot. The concrete tower is approximately 160 meters (525 feet) in height with a base diameter of 21 meters (70 feet). Commonwealth Dynamics Inc. provided the tower for the Crescent Dunes molten salt tower power facility and provided a budgetary quote for this project based on a 600-foot tower. The optimum tower height is very sensitive to tower cost. S&L did a preliminary scaling of cost based on a reduced height, but this design needs to be further optimized for the specific receiver and using an appropriate cost scaling function based on tower height and actual seismic, weight and wind loads.

3.3.4 Molten Salt Central Receiver (MSCR)

The molten-salt tower solar plant has a thermal rating of 400 MW_t. This is a custom size receiver appropriate for the square mile solar field configuration. S&L has received quotes for the receiver from two vendors, although the receiver in theory could be supplied by any one of several molten-salt receiver vendors, such as Aalborg, GE/Alstom, Solar Reserve/Rocketdyne, CMI, Foster Wheeler, and others.

The Molten Salt Central Receiver (MSCR) consists of the following components:

- Receiver circulation pumps supply cold salt to the receiver inlet vessel. These vertical turbine pumps are mounted on a structure overhanging the top of the cold salt storage tank and are driven by electric motors with a variable speed drive.
- Receiver Inlet Vessel supplies a temporary flow to the receiver in the event of a loss of the receiver pump or site power.
- Receiver Absorber Panels consist of a group of parallel tubes, upper and lower headers, support structure, upper and lower oven boxes, insulation, and temperature instruments. Multiple panels in series are required and arranged in 2 parallel flow paths.
- Internal receiver piping includes inter-panel piping, crossovers, valves, fill and drain lines, and inline instruments for flow, pressure, and temperature.
- Radiant electric heaters are furnished for the oven boxes, and electric heat tracing for the salt piping, instruments, and valves.
- The receiver design includes structural supports, ladders, and platforms. A receiver tower crane will allow access to receiver panels for installation and replacement.
- The hot molten salt is collected in the Receiver Outlet Vessel and the Downcomer discharges to the Hot Salt Tank.

- Since the Hot Salt Tank operates at atmospheric pressure, the static head in the Downcomer from the Receiver Outlet Vessel must be dissipated before the salt enters the Hot Salt Tank. Cascade (Waterfall) operation is selected for the DSP plant design, because there are no active control mechanisms such as control valves that are subject to severe thermal gradients.

The P&ID for the receiver molten-salt circuit is included in Appendix B.

Aalborg CSP provided a 400 MW_t MSCR design optimized for this project. The solar field layout was optimized to accommodate the flux limitation and design rating of the Aalborg receiver. Aalborg provided a budgetary quote for the receiver. The receiver is designed such that tubes and panels can be rapidly replaced if there is any damage.

Flowserve has provided molten salt vertical pumps for molten salt tower solar power facilities and provided budgetary quotes for this project.

3.3.5 Thermal Storage System (TSS)

The plant will have a capacity of 3000 MWh_t of thermal storage. This is the thermal energy required for approximately 5 hours of full load output for a 250 MW_e gross power cycle. This amount allows the plant to store energy during the daytime and not have to generate power during daylight hours. The Thermal Storage System (TSS) consists of the following components:

- Cold salt storage tank receives cold salt from steam generator and supplies cold salt to the receiver. The plant requires one cold salt tank.
- Hot salt storage tank stores hot salt from the receiver and supplies hot salt to the steam generator. The plant requires one hot salt tank.
- A Cold Tank electric heater will be specified to maintain the required salt temperature during extended downtimes.
- A Hot tank recirculation pump and electric heater will also be provided.
- Salt pumps will be long shafted cantilever pumps mounted on a structure above the salt tanks.

The tanks are of vertical cylindrical design, with domed roofs. The tank diameter is 140 feet and the wall height is 42 feet. The tank is designed in accordance with API 650. Since API 650 does not cover design temperatures above 500 °F, allowable stresses for both the cold and the hot tank materials is derived from those in Section II of the Boiler & Pressure Vessel Code.

The tank volume will be such that the entire salt inventory in the plant can be stored in either tank. To transfer the stagnant inventory from one tank to the other, the salt pumps will be provided with tail extensions, which reach much closer to the tank floor than the normal suction bell. All tank nozzles and man-ways will be located on the roof. The salt tank foundations are a specialized design for the high temperature. CBI Services Inc. has provided thermal storage tanks for molten salt tower power facilities and provided S&L a quote for this project.

3.3.6 Steam Generator System (SGS)

In recent years, steam generators have been one on the main problem areas for CSP plants. One of the primary causes is the daily thermal cycling of the heat exchangers. The DSP plant will need a reliable steam generator design for flexible and quicker cycling than most CSP plants have historically needed. S&L has identified a molten-salt steam generator design by Aalborg that satisfies the operational requirements of the DSP plant. This allows fast startups and rapid transient operation.

The modular Aalborg design, shown in Figure 7, uses header coil type heat exchangers that can accommodate fast-starts and cycling operation. During start-up, the heat exchangers experience different temperature changes: the superheater and the reheater have the largest changes, the preheater the smallest. The allowable rate of temperature change should be as large as practical to reduce both the daily startup times and the start-up energies. The superheater and the reheater will have provisions for monitoring the temperatures along the length of the tube bundle. The evaporator, the preheater (economizer), and the startup feedwater heater will be sized for both 100% duty and for auxiliary steam production. During holding periods, the mode of operation is to keep the heat exchangers filled on the salt side, and to operate the attemperation pump as required to keep the exchanger temperatures at the required temperatures for a fast start. The 250 MW DSP plant will use five of the Aalborg SGS modules. The P&ID for the steam generator molten-salt and steam circuits are included in Appendix B.

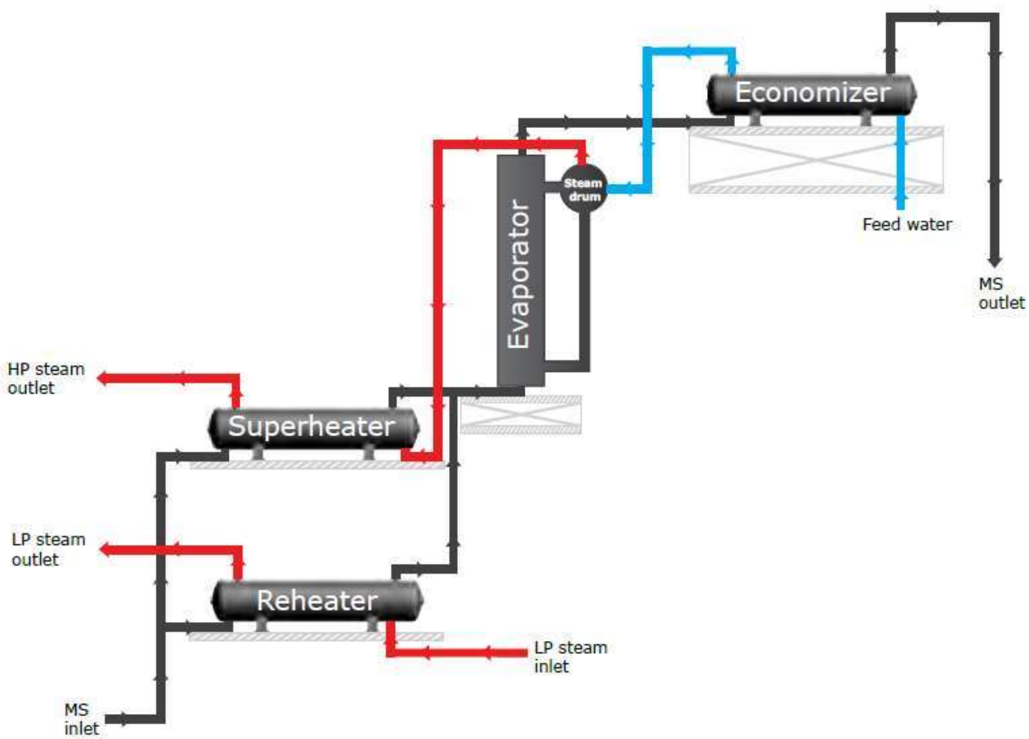


Figure 7 Aalborg Header Coil Steam Generator Design

3.3.7 Steam Turbine/Power Cycle

S&L evaluated turbines from several suppliers, but the Siemens SST-900 reheat steam turbine appears to be an excellent choice for the DSP plant, offering good efficiency and rapid starts and ramps required for the DSP application. A 250 MW_e gross steam power cycle has been selected for the plant because this is the maximum size available for the SST-900. Initially both reheat and non-reheat turbine designs were considered. The reheat design was selected because it appeared to meet the operational requirements, was more efficient and was judged to be a more cost-effective solution overall for the project. With improved automation now available, the added complexity of the reheat design is not considered to be an issue from a reliability standpoint as it has been for some plants in the past. The new control systems can fully automate the start-up and shutdown of the plant.

The 250 MW_e DSP plant has a larger power cycle than has been used in any previous CSP plant and is about double the rating of the power cycle at the current Crescent Dunes plant. S&L has confirmed with the turbine vendor that the 250 MW turbine size will work for the application and represents a low technology risk. S&L has completed a detailed equipment layout for the power block around the tower and finds the cooling towers, steam generator heat exchangers and other equipment required for the larger turbine should fit within the planned power block area.

The steam turbine generator is designed for seven stages of feedwater heating. There are three low-pressure (LP) feedwater heaters, one deaerator, three high-pressure (HP) feedwater heaters and a topping desuperheater. The turbine and controls are capable of sliding pressure operation based on the coordinated controls within the plant DCS. The Electric Generator is 60 hertz, three-phase and of TEWAC construction. The Turbine Control System (TCS) can monitor, control and interface to all equipment provided by steam turbine vendor. A turbine stress controller is incorporated into the TCS to shorten start up times without reducing the lifetime of heat-critical turbine components. A complete Turbine Supervisory Instrumentation (TSI) system is provided.

Reliability, availability, and maintainability are of the utmost importance in the design of this steam-turbine generator. Importantly, the design and supply of turbine, generator and all auxiliary components will be capable of a minimum of 30 years operation without distress due to high output load or daily cycling service. The units are anticipated to come on and off line daily and shall be designed to minimize startup and shutdown requirements. The turbine is able to handle the two starts per day during the winter months. At worst this will have a minor effect on turbine overhaul schedules.

The design assumes the power plant will have a hybrid wet/dry cooling system for condensing the exhaust steam from the steam turbine generator. The plant is designed for 113°F (44.8°C) ambient temperature. The hybrid cooling system is parallel wet/dry cooling system comprised of an air-cooled condenser, surface condenser and mechanical draft wet cooling tower. There are several vendors of hybrid cooling systems. The dry air-cooled condenser (ACC) is designed to handle the entire cooling load for temperatures up to 77°F (25°C). The wet cooling tower is sized so that it will enable the plant to operate at full power output at 113°F. In the hybrid design, the dry tower is 80% as large of the ACC-only design, and the wet tower is 70% the size of a wet-only tower.

Power Cycle Heat Balance: Sargent & Lundy evaluated the power cycle with wet, dry, and hybrid parallel wet/dry cooling systems. Table 2 shows how the efficiency of the power cycle varies as a function of ambient temperature for each type of cooling system. The wet cooling system is the preferred option from a performance and cost standpoint. The dry cooled system is the best option from a water use standpoint but is more expensive and less efficient at higher ambient temperatures. The hybrid cooling system maintains performance at high ambient temperatures, is cheaper than a dry cooled system, and reduces water use compared to a wet cooled system.

Table 2 Power Plant Efficiency as a function of Cooling Technology and Ambient Temperature (Source: Sargent & Lundy)

	T_{db} °C / °F	P_{gross} MW_e	P_{net} MW_e	η_{gross} %	η_{net} %
Wet Cooled	44.8 / 112	250.0	243.1	44.8	43.5
Dry Cooled	44.8 / 112	250.0	238.5	42.3	40.4
	35 / 95	257.3	245.7	43.6	41.6
	23.9 / 75	259.7	248.2	44.0	42.0
	12.8 / 55	259.8	248.3	44.0	42.0
Parallel Wet/Dry	44.8 / 112	250.0	240.0	44.0	42.3
	40.5 / 105	250.8	241.6	44.1	42.5
	35 / 95	251.0	240.9	44.2	42.5
	23.9 / 75	250.9	241.8	44.2	42.6

Plant Start-up Time: At the start of the project, the goal was to ensure that the plant could start up (initiation of start to full load) in under one hour, assuming the plant had operated within the previous 24 hours. APS indicated this was adequate for a block dispatch type of operation that could be scheduled 24 hours or one hour in advance. The 2017 APS peaking Capacity RFP indicated that quicker starts were preferred. In discussions with Siemens and Aalborg, Sargent & Lundy determined that the DSP plant could be designed to start-up in 25 minutes. Figure 8 shows the start-up curves for the turbine and steam generator. To achieve the fast start capability an external heating system will be required to maintain critical temperatures within the turbine. Two methods are available. One method is to maintain the necessary temperature profile utilizing an external electric heating "blanket" covering the turbine. The other is to introduce auxiliary steam to heat the turbine. With the auxiliary steam method, the turbine seals and condenser vacuum must be maintained throughout the holding period. If the steam turbine generator is dispatched in a day-ahead market, the electric heating method may offer economic advantages.

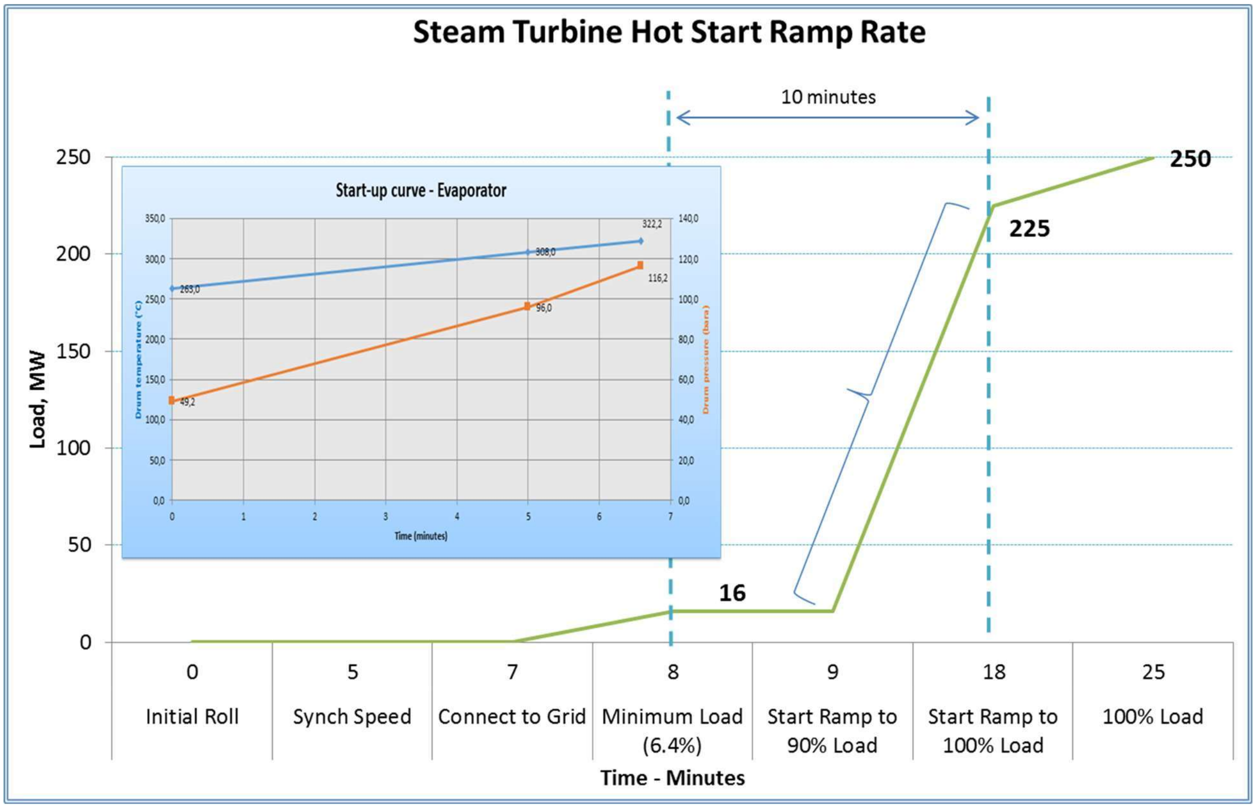


Figure 8 Siemens Flex Start Steam Turbine Start-up Curves

Plant Water Use: S&L developed water balances for the design point of the wet, dry, and parallel wet/dry cooled plants. The water balances are based on water quality assumptions for well water from the proposed site in Arizona. The water balance shows all the water steams and uses in the power plant. The design of the water treatment system is very sensitive to the quality of make-up water for the plant as well as permitting limitations on the quality of the water in the cooling tower and the amount of water that can be discharged to the evaporation pond. In addition, the water treatment system can be a very labor intensive and an expensive O&M item. It is also important that the design of the water treatment system is appropriate for type of operation of the plant. The DSP plant will be a peaking plant and only operate for a few hours per day, with the majority of water use during the summer when the wet cooling tower is needed. During half of the year, the wet tower will only be needed for auxiliary cooling. S&L's water treatment expert has experience with plants in Arizona and talked to water treatment equipment supply venders to identify the simplest and lowest cost approach. The design would need to be approved by the local water and air quality permitting authorities. The S&L design assumes water quality in the cooling tower is maintained by blowing down water to an evaporation pond. It is also possible to do further treatment of the blowdown and reclaim virtually all of the water, referred to as zero liquid discharge (ZLD). This is an expensive and labor-intensive process and difficult to maintain for a cycling power plant. Sargent & Lundy proposed a simple water treatment system design that would be low cost and minimize labor and chemical usage. Since the plant operates at a very low capacity factor, and uses a hybrid cooling design to save water, it doesn't make sense to invest in an expensive water reclamation system to reduce water discharge from the plant. Table 3 shows a comparison of the annual water usage estimated by Solar Dynamics for each of the three cooling systems and a comparison to the water use by a farm of similar size. The cheapest option is to build evaporation ponds. Water reclamation would only save 79 acre-feet of water (Evap. Pond Blowdown) at an annual value of between $5,000 and $40,000 dollars per year of water cost depending on whether the savings are valued at the agricultural farm or industrial solar plant water price. This cost savings does not justify the added capital cost for ZLD or other treatment approaches to reclaim water from the blow down.

Table 3 Water Use Analysis for DSP Project in Arizona

Acre Feet of Water per year	**Total Usage**	Wet Tower Evaporation	Evap. Pond Blowdown	Mirror Wash Use	Power Plant Losses
Farm (Solana 1 Sq. Mile)	**10,000**				
Wet Cooling	**961**	852	92	13	5
Dry Cooling	**167**	104	54	13	5
Wet/Dry Parallel	**421**	325	79	13	5

Notes: **1)** Water cost: Farming $65/acre-ft, Solar Plant $500/acre-ft
2) Evaporation Pond Sizing Analysis:
- 79 acre-feet of blowdown to ponds
- 60” of evaporation / year
- 16 acres of pond required (S&L Assumes 20 acre pond in cost estimate)

3) Water Reduction Options (Sargent & Lundy Estimates)
- Crystallization ZLD $30 M
- CT side stream Demineralizer $15 M
- Deep Well injection $10 M - Not good luck with this.
- Evap Ponds $ 5 M (20 acre pond)

3.3.8 Plant Electrical Overview

The plant electrical overview is generated on a Single Line Diagram. The following major equipment are shown on the single line:

- Electrical Generator – 300 MVA
- Generator Step-Up Transformer (GSU) 230kV/17.5 kV
- Unit Auxiliary Transformer (UAT)
- Generator Circuit Breaker
- Dead-end Structure
- 4.16 kV Bus Connections
- Generator Protection
- All major consumers

3.3.9 Plant Control Systems

The integration of the control systems for molten-salt pumps, the SGS and the STG is a critical step in achieving a fully dispatchable MST power plant. There are many considerations in the design of a modern steam power plant for peaking service. Thermal stress management; steam chemistry; establishment of steam seals; vibration, over speed and thrust controls are vital for minimizing adverse impacts on reliability, availability and maintainability. The following features have been successfully applied on “fast-start” STGs utilized on several combined cycle facilities and are to be implemented into the design of a MST peaker plant. The essential control systems for peaking service include the following;

- Automated steam turbine start-up/holding operating modes without manual operation or intervention,
- Control system to maintain pressure and temperature in the main components utilizing an auxiliary heat source (such as auxiliary steam boiler or heat tracing) during holding periods. Steam turbine heat-critical components will define allowable start conditions: hot start, warm start, cold start, and ambient start.
- Control system to maintain vacuum on steam turbine seals and condensing system.
- Control system to maintain the water/steam cycle within specified chemistry limits to enhance the start-up procedure.
- Automated synchronizing via external auto-synchronizer,
- The turbine load control system providing control modes for: steam generation system (SGS) follow, steam turbine generator (STG) follow, MW control local or MW control remote (AGC), with mode selected from plant DCS,
- Automatic turbine load control from turning gear to target operating point at maximum rate compatible with the thermal state of the turbine (ambient, cold, warm, hot), the steam inlet conditions and the allowable expenditures of turbine life expectancy,
- A turbine stress controller to control thermal stress without reducing the lifetime of heat-critical turbine components
- Sliding pressure or constant pressure operating mode of the SGS and STG.
- Thermal stress management software to monitor the stresses in the SGS heat exchangers during rapid loading (start-up, ramping and shutdown) and minimize the impact on SGS life expectancy.

The DSP plant will be designed for fast start-up and ramping. The plant will be able to be maintained in a hot thermal hold state such that it is available to make a hot start-up when called upon. The integrated control system shall be designed to achieve required start-up times and ramp rates for a hot start. The desired operational flexibility required for the DSP plant is possible with the appropriate design to maintain a hot thermal hold state and integration of the SGS and STG control systems.

3.4 Plant Performance Modeling

The NREL System Advisor Model (SAM) was used for simulating the annual output of the DSP plant. Modeling Assumptions:

- The CSP power tower molten salt model was used.
- The solar resource data was the current NSRDB TMY dataset for the Harquahala site. The TMY resource is 2900 kW/m^2-yr (7.95 kW/m^2-day).
- Solar Pilot was used to optimize the heliostat field layout. The heliostat positions were then input into SAM.
- The BrightSource V2.4 heliostat design was assumed for the heliostat field.
- The molten salt receiver is a 400 MW$_t$ receiver design provided by Aalborg. Aalborg provided the flux limits for the tower design optimization.
- The power cycle is modeled using the user defined power cycle option. To evaluate the performance of a peaking type plant, it is important that the performance model reflect the actual efficiencies of the plant under any operating condition. The user defined power cycle model allows a power cycle efficiency matrix to be entered directly into the model as a function of load, HTF inlet temperature, and ambient temperature. This approach accounts for both the steam cycle and the steam generator. Sargent & Lundy developed the off-design efficiency curves for the steam turbine using their proprietary version of Gate Cycle. Solar Dynamics developed an integrated power cycle model that includes the solar steam generator in IPSEpro. We matched the S&L steam turbine performance and generated the matrixes for the SAM user defined power cycle inputs. Unfortunately, the user defined power cycle currently only works for the dry cooled power cycle option, constraining our performance calculation to the dry cooled power cycle case. The wet and hybrid cooled performance results are expected to be better than the dry cooled results.
- Plant parasitic electric consumption: We did a preliminary check on parasitic loads by system, recognizing that the current input assumptions do not allow sufficient flexibility to accurately model the subsystem parasitic loads. In a commercial project this data would be accurately post processed in a spreadsheet.
- To accurately model expected plant performance and account for transient behavior, it would be necessary to model the plant on a smaller time increment than hourly. Although technically feasible, it is currently difficult to do in SAM as it is based on hourly DNI and input factors. The hourly output gives a reasonable expectation of performance, but likely misses the transient behavior that a real plant would experience. Other post conceptual modeling should be conducted to look at transients in the solar field (solar resource special and temporal transients) and receiver (flux and temperature transients) and transients in the operation of the power cycle (steam generator temperature and turbine generator steam condition and power generation transients). This should include evaluation of start-up and shutdown conditions, standby conditions, as well as upset transient conditions.

3.4.1 Design Optimization

The DSP design effort focuses on optimizing the plant for application to the APS 2017 Peaking Capacity RFP. The plant is optimized to meet the APS summer peaking requirement, delivering a high capacity factor during the "Most Preferred" TOD period. Based on feedback from APS, we evaluated designs for both 6 hours (HE 4 to HE 9) and 5 hours (HE 5 to HE 9) of summer peaking capacity. APS believes that over time, the first hour of the Summer most preferred TOD period would likely become less valuable because it will increasingly be supplied by net metered rooftop PV. Thus, if a lower price could be achieved, they would prefer a plant that delivers 5-hours of firm capacity that started an hour later rather than a full 6-hour resource in their TOD plot. The secondary objective of the design optimization is to minimize the amount of "Less Preferred" and "No Must Take Energy" generation. The goal is to achieve as high a capacity factor possible during the summer peak at the lowest capacity price possible. The question becomes what is an acceptable capacity factor? For this analysis it seems economically feasible to produce about 90% or higher capacity factor during the most preferred hours.

Table 4 shows several configurations that were evaluated with solar field thermal ratings of 350 to 500 MW_t, and for both 5 and 6 hours of thermal energy storage. All plants use the 250 MW gross steam turbine. Note the solar fields from 350 to 450 MW_t all use the square mile site. The 500 MW_t case uses a larger 1.25-mile by 1.25-mile site. The table shows the key design data for each plant, the performance, capital cost, and both tolling (capacity) and regular PPA prices. The overnight capital cost includes all the cost to build the plant excluding financing and interest costs. The total project costs include financing and interest during construction. The 500 MW_t system (Case 4) offers the best summer 6-hour "most preferred" performance. It has the lowest PPA price, but it also has the highest tolling PPA (capacity) price. The 400 MW_t case (Case 2) has the similar summer "most preferred" performance assuming 5 hours, and has a lower tolling PPA price (annual capacity payment). Note the PPA price is substantially higher.

The final case, Case 5, is a further fine tuning of the 400 MW_t case to reduce the annual capacity payment while maintaining good summer "most preferred" performance. This results in a 387 MW_t rated solar field although the receiver is assumed to be the same design and cost as the 400 MW_t design. This case is final design configuration and used for the S&L cost estimate and final financial analysis.

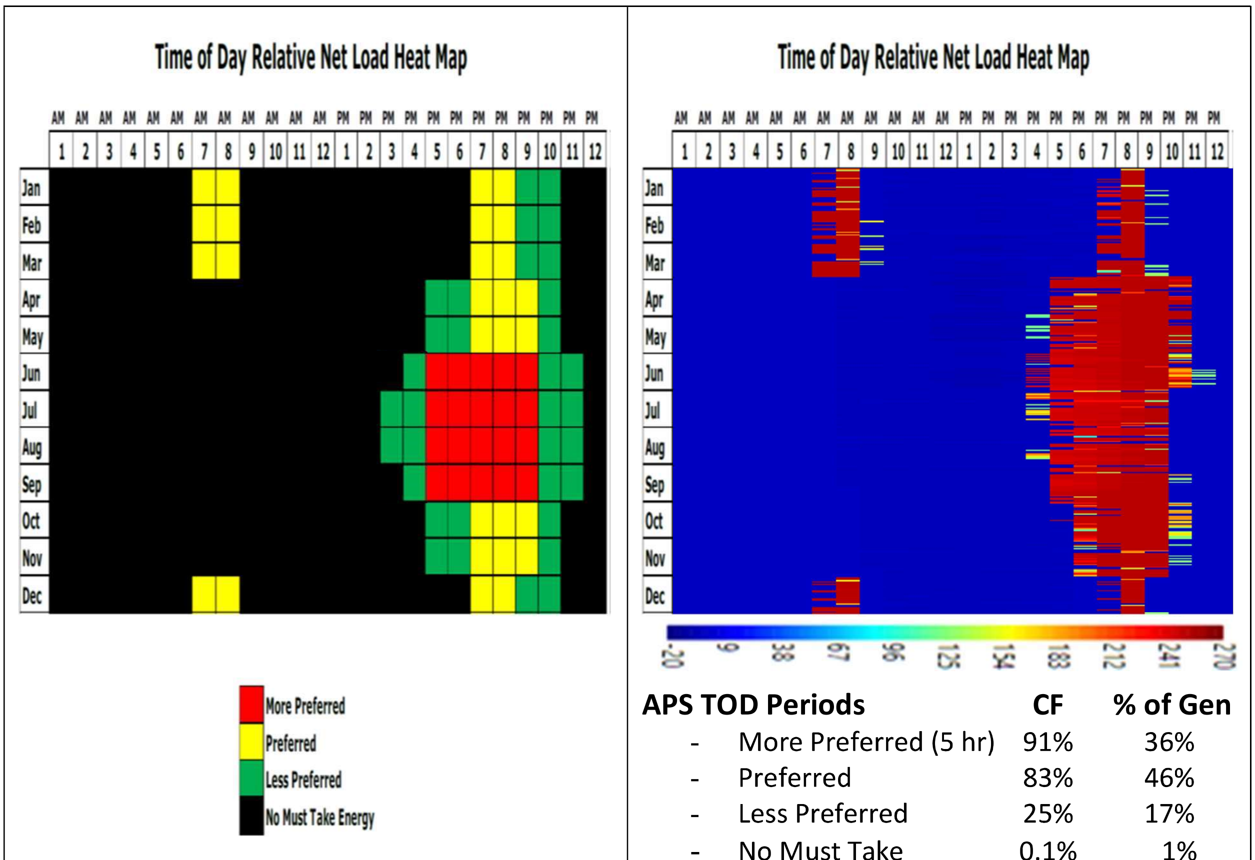
SolarDynamics

Table 4 APS DSP Design Optimization - Case Runs

Plant Design	Units	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**
Turbine Gross Output	MWe	250	250	250	250	250
Turbine Net Output	MWe	**230**	**230**	**230**	**230**	**230**
SF Thermal Rating	MWt	**350**	**400**	**450**	**500**	**387**
# of Heliostats	#	32,120	37,904	49,576	45,117	32,973
Heliostat Area	m2	667,454	787,645	1,030,189	937,531	685,179
Tower Optical Height	m	156	175	187	178	168.5
Tower Offset	m	-100	0	-25	0	-35
Receiver Height	m	14.0	14.0	14.5	16.0	14.0
Receiver Diameter	m	12.2	12.2	13.0	14.0	12.2
Receiver Area	m2	537	537	592	704	537
- Max Flux	kW/m2	1194	1176	1183	1176	1112
- Ave. Flux	kW/m2	767	871	869	830	801
Solar Field Efficiency (ann)	%	60.0%	57.8%	54.0%	60.7%	61.2%
Thermal Storage Size	hours	5	5	6	6	5
Land Area	acres	640	640	640	840	640
Performance						
Annual Net Sales	GWH	319	351	399	462	334
Annual Capacity Factor	% CF	15.8%	17.4%	19.8%	22.9%	16.6%
Most Preferred (6 hrs)	% CF			**89.4%**	**93.3%**	
Most Preferred (5 hrs)		**89.8%**	**93.4%**			**93.5%**
Preferred	% CF	83.2%	74.9%	89.1%	92.3%	83.9%
Less Preferred	% CF	17.1%	27.4%	33.2%	48.3%	19.4%
No Must Take	% CF	0.1%	0.0%	0.6%	1.7%	0.2%
Cost						
EPC Overnight Capital Cost	$/kW	**$2,576**	**$2,673**	**$2,876**	**$2,930**	**$2,596**
EPC Overnight Capital Cost	$M	$592	$615	$662	$674	**$597**
Total Project Cost	$M	$728	$754	$808	$827	**$734**
Annual Capacity Payment	**$/kW-yr**	**$305**	**$316**	**$333**	**$339**	**$307**
PPA Price	**$/MWh**	**$230**	**$216**	**$200**	**$176**	**$222**

3.4.2 Performance Results

The new dispatch optimizer in SAM was used to optimize generation during the APS 2017 "More Preferred" and "Preferred" time of delivery (TOD) periods. The dispatch optimizer was found to work very well at dispatching power to the priority periods. Figure 9 shows the APS TOD periods and the SAM performance model result. If the plant was operated under a tolling agreement, the plant would be dispatched to meet the actual system requirements daily. The output would likely look somewhat different than what is seen in Figure 9. For example, in winter months, on days where the plant is currently shown operating for only one hour in the morning and one hour in the evening, APS would likely dispatch the plant for 2 hours either in the morning or the afternoon depending on which peak was larger. This would give them more load following flexibility with the output of the DSP plant and less dispatch complexity to manage.



(a) APS Peaking Capacity TOD Periods (b) SAM DSP Plant Output

Figure 9 APS 2017 Peaking RFP TOD Periods and SAM Optimized DSP Dispatch Model

Table 5 shows the net generation and net consumption of the DSP plant during each month and TOD period. These numbers were post processed as SAM does not currently output these figures separately. This illustrates how the actual power from plants is measured by utilities. Typically, off-line consumption (power used by the plant when it is not generating) needs to be tracked separately, because plants pay a different price for power they consume than they do for the power they produce. Off-line power consumption also generates demand charges that can be significant if they occur during peak demand periods.

Table 5 DSP Plant Net Generation and Net Consumption (APS Reference Case)

	Net Generation (Sales of Energy)					Net Consumption (Purchased Energy)					Capacity Calculation			
Time stamp	Most Perferred MWh	Perferred MWh	Less Perferred MWh	No Must Take Energy MWh	Total MWh	Most Perferred MWh	Perferred MWh	Less Perferred MWh	No Must Take Energy MWh	Total MWh	Most Perferred	Perferred	Less Perferred	No Must Take Energy
Jan	0	18,531	362	0	18,893	0	(75)	(81)	(1,744)	(1,900)		65%	3%	0%
Feb	0	19,975	236	277	20,488	0	(52)	(74)	(1,633)	(1,760)		78%	2%	0%
Mar	0	23,895	1,190	676	25,761	0	(39)	(74)	(1,920)	(2,034)		84%	8%	1%
Apr	0	20,155	15,156	0	35,311	0	(10)	(60)	(1,890)	(1,959)		97%	73%	0%
May	0	21,793	17,483	1,006	40,282	0	0	(49)	(1,971)	(2,021)		102%	82%	1%
Jun	34,283	0	7,860	0	42,143	(8)	0	(145)	(1,762)	(1,914)	99%		38%	0%
Jul	31,393	0	1,916	0	33,309	(55)	0	(365)	(1,486)	(1,906)	88%		7%	0%
Aug	30,571	0	874	0	31,445	(69)	0	(391)	(1,456)	(1,916)	86%		3%	0%
Sep	32,072	0	524	0	32,597	(35)	0	(247)	(1,600)	(1,882)	93%		3%	0%
Oct	0	21,424	9,656	0	31,080	0	(4)	(167)	(1,841)	(2,012)		100%	45%	0%
Nov	0	18,580	4,669	0	23,249	0	(17)	(193)	(1,649)	(1,858)		90%	23%	0%
Dec	0	17,820	532	0	18,352	0	(80)	(81)	(1,675)	(1,836)		62%	4%	0%
Year	**128,319**	**162,173**	**60,458**	**1,960**	**352,910**	**(167)**	**(277)**	**(1,928)**	**(20,628)**	**(22,999)**	**91.5%**	**83.0%**	**25.4%**	**0.1%**
	36.4%	46.0%	17.1%	0.6%		0.7%	1.2%	8.4%	89.7%					

Table 6 shows the average net capacity factor of the plant during each hour for each month. Again, the plant is capable of dispatching power to the priority TOD periods. July and August are the more difficult summer months to maintain high capacity factors during the most preferred periods. But the plant achieves high capacity factors for at least three or four hours during all the summer months. The reduced output in July and August is due to the summer monsoon weather that Arizona experiences.

Table 6 DSP Plant Net Capacity Factor During Each Hour (APS Reference Case)

Time of Day Net Output Map — Net Capacity 230 MW

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-1%	-1%	-1%	-1%	-1%	-1%	39%	93%	-1%	-2%	-2%	-2%	-3%	-2%	-2%	-2%	-2%	-1%	31%	96%	5%	-1%	-1%	-1%
2	-1%	-1%	-1%	-1%	-1%	-1%	58%	99%	3%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	50%	102%	3%	-1%	-1%	-1%
3	-1%	-1%	-1%	-1%	-1%	-1%	69%	98%	8%	-2%	-2%	-2%	-2%	-3%	-3%	-2%	-2%	-2%	72%	96%	13%	3%	-1%	-1%
4	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-3%	-3%	-3%	-2%	69%	83%	91%	102%	99%	66%	-1%	-1%
5	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	12%	78%	89%	101%	102%	102%	77%	-1%	-1%
6	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	36%	92%	100%	101%	102%	102%	66%	10%	-1%
7	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	25%	69%	95%	98%	93%	84%	-1%	-1%	-1%
8	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	10%	60%	94%	94%	92%	89%	-1%	-1%	-1%
9	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-3%	-3%	-2%	79%	98%	97%	95%	95%	7%	-1%	-1%
10	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-3%	-3%	-3%	-3%	-3%	-2%	4%	85%	96%	102%	102%	44%	-1%	-1%
11	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-3%	-2%	-2%	-2%	-2%	57%	75%	99%	95%	10%	-1%	-1%
12	-1%	-1%	-1%	-1%	-1%	-1%	39%	93%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	19%	97%	4%	2%	-1%	-1%

Note the plant was designed to optimize summer output from hour ending 17 to hour ending 21 (5 hours).

3.4.3 Solar Correlation with Peak Demand

It is important to understand whether there is a correlation between peak demand and solar resource. This will help determine if a solar plant is a good peaking resource. Solar Dynamics conducted an analysis to evaluate the correlation between APS peak demand and solar resource. Figure 10 looks at when the peak load days occurred during the period 2006 to 2015. The results confirm that the peak system demand occurs during the period mid-June through the end of August. It is interesting to see the reduction in peak load after 2007 and that peak loads in recent years have yet to exceed the loads experienced in 2006 and 2007 timeframe.

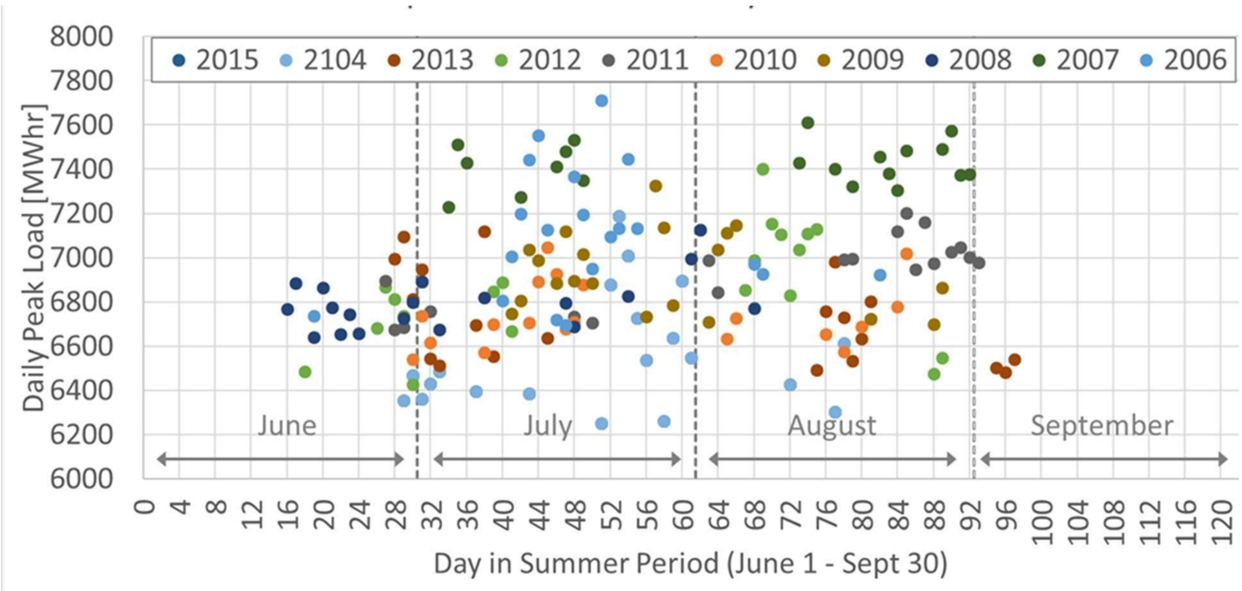


Figure 10 Top Summer Load Days for the Years 2006 to 2015

The question is whether there is a correlation between the solar resource and peak loads. Is it sunny on the days with peak loads so that a solar power plant could be relied upon to provide peaking power? Figure 11 shows the correlation between peak loads and solar resource for our primary site. We use percent of clear sky radiation as the metric for the solar resource. Any reduction below about 95% indicates that there are clouds present. Although it is generally sunny during peak days and there are no days that are completely overcast, there are many days that appear to be relatively cloudy with clear sky radiation below 80% and even a few days below 50%. To understand how significant this was we modeled the performance of our optimum plant configuration for the top 20 days to determine how it would perform on these peak days.

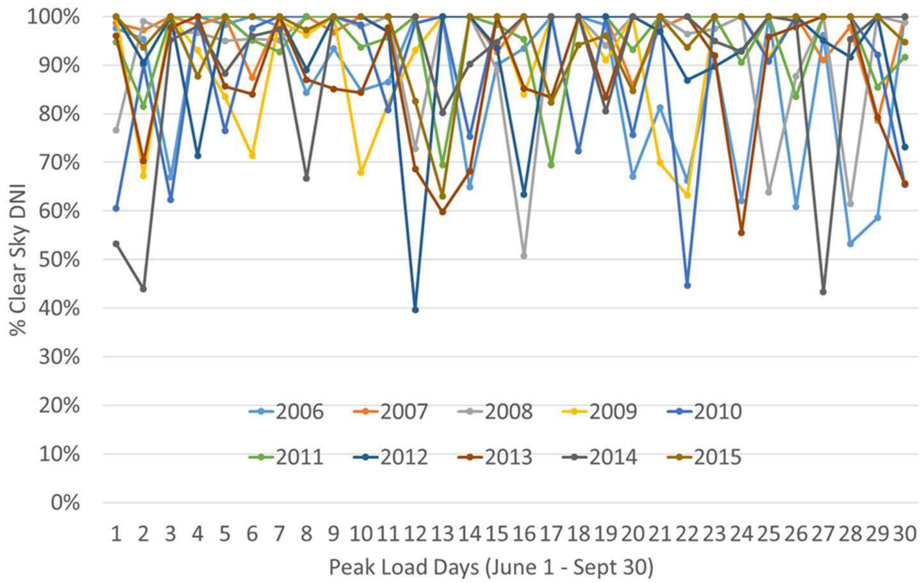


Figure 11 Percent Clear Sky DNI for Top 30 Summer Load Days for Site #1

Table 7 shows the on-peak performance for each of the top 20 peak days for the 10 years between 2006 and 2015. A 100% value means the plant operated at 100% of its design output over the 6 hours between 3 pm and 9 pm. Although, there are many peak days with reduced on-peak output due to clouds, there are no days with zero output and only 4 days below 50% capacity factor during the 10 years of data. The average capacity factor over the top five peak days is 91% and 94% over the top 10 and 20 days. When this chart was shown to APS they indicated that the performance was acceptable and similar to conventional resources in terms of availability.

Table 7 Projected On-peak Performance for the top 20 Peak Load days for 2006 to 2015

Peak Load Day Ranking	Net Design Capacity Factor (3-9pm) 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Avg
1	100%	102%	76%	101%	52%	98%	101%	101%	41%	99%	87%
2	100%	99%	102%	65%	89%	80%	101%	78%	35%	95%	84%
3	70%	102%	101%	102%	65%	98%	101%	100%	99%	98%	94%
4	101%	102%	101%	100%	101%	99%	63%	101%	101%	82%	95%
5	101%	99%	100%	86%	78%	99%	101%	101%	94%	101%	96%
6	102%	85%	101%	77%	102%	99%	101%	87%	102%	102%	96%
7	101%	101%	102%	101%	101%	95%	101%	101%	101%	99%	100%
8	90%	100%	101%	101%	102%	101%	99%	92%	65%	102%	95%
9	103%	98%	101%	101%	102%	101%	102%	101%	102%	101%	101%
10	87%	101%	102%	69%	101%	96%	102%	98%	103%	102%	96%
11	97%	101%	101%	98%	80%	99%	101%	102%	103%	101%	98%
12	102%	102%	68%	99%	101%	98%	28%	69%	102%	75%	84%
13	103%	100%	102%	100%	102%	50%	102%	58%	93%	63%	87%
14	48%	99%	102%	101%	80%	101%	102%	79%	97%	102%	91%
15	99%	95%	101%	102%	102%	101%	102%	99%	101%	102%	100%
16	93%	102%	54%	101%	102%	100%	76%	96%	102%	100%	93%
17	102%	102%	102%	101%	102%	76%	100%	93%	103%	84%	96%
18	102%	100%	102%	100%	79%	102%	102%	100%	104%	102%	99%
19	102%	102%	95%	93%	102%	102%	100%	93%	86%	98%	97%
20	70%	101%	101%	101%	74%	101%	102%	100%	103%	85%	94%
Top 5 days	94%	101%	96%	91%	77%	95%	93%	96%	74%	95%	91%
Top 10 days	96%	99%	99%	90%	89%	97%	97%	96%	84%	98%	94%
Top 20 days	94%	100%	96%	95%	91%	95%	94%	92%	92%	95%	94%

One question coming from this analysis is whether the performance seen was due to localized cloud cover at the site selected or whether it was a general trend for the entire region. To evaluate this, we selected at 8 sites across Arizona. Figure 12 shows the performance of DSP plants located at each of the 8 sites. Site 5 was our reference site and site 6 is the Solana site. There was a 14% difference between the net generation from the best to the worst sites with our reference site right in the middle. There is an even larger variation in the July on-peak performance between sites. Clearly it is very important to evaluate the summer on-peak performance and consider selecting the site based on the expected summer on-peak performance.

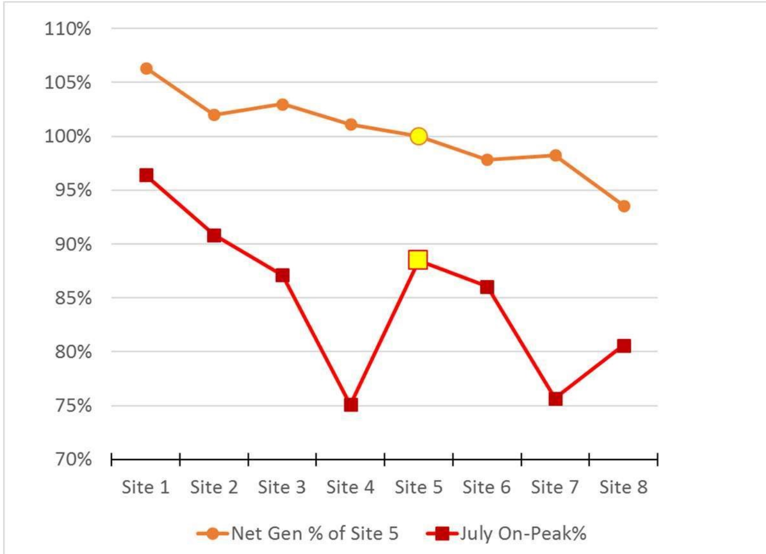


Figure 12 The Relative Performance of DSP Plants at 8 Sites Across Arizona

Figure 13 shows the on-peak capacity factor for each summer month for each of the 8 sites considered in Arizona. Some of the sites, especially site 1, appear to be significantly better than others for July and August performance.

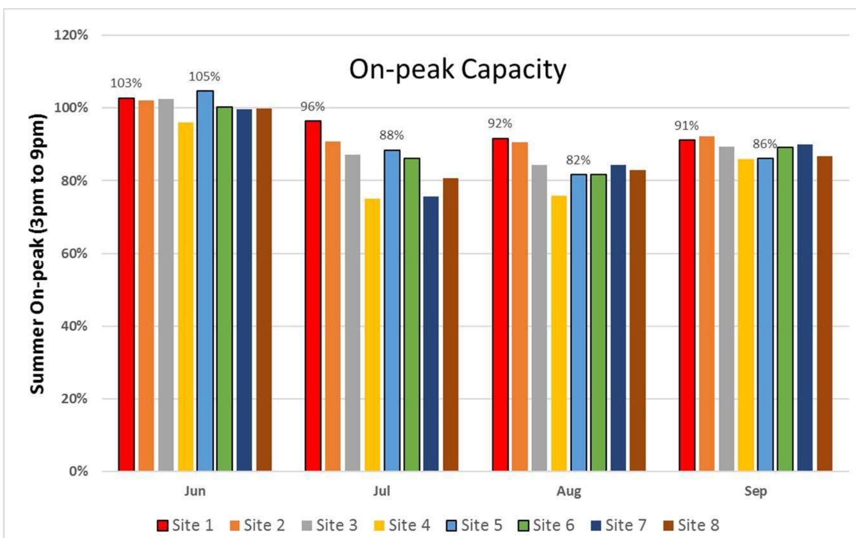


Figure 13 Summer On-peak Capacity Factor by Month for 8 Sites Across Arizona

3.5 EPC Schedule

Historically, the schedules for developing CSP plants in the U.S. have been relatively long. The Solana Project took about 6.5 years from initial proposal to commercial operation. This included development, permitting, financing, engineering and procurement, construction, and commissioning. The schedule was delayed in part due to difficulties in financing the plant following the 2008 financial crisis. Within the 6.5 years, the EPC schedule was nearly 3 full years. For CSP plants to be more financially attractive they need to have shorter development and EPC schedules. As utilities try to delay making purchasing decisions for as long as possible they are looking for new generators to reduce the project development and construction window as much as possible. Utilities would ideally like to sign a PPA and have new resource be able to be online within 24 to 36 months. This can only occur if technologies can be deployed very rapidly or the projects are well along in their development cycle by the time the PPA is signed. The latter is not desirable to equity and debt since it means a large amount of money must be spent at risk before the certainty of a signed PPA.

Molten-salt tower plants currently have EPC schedules estimated to be about 30 to 36 months. This is often preceded by an additional 6 months of early engineering and long lead time procurement activities that may occur before project financial close. The recent APS Peaking Capacity RFP required plants to be online between 36 and 41 months after the PPA was signed. Any delays in signing the PPA would shorten this window. Considering that the plant needs to complete permitting and financing of the project before the actual EPC contract can begin, the APS schedule would be challenging to meet with the current MST technology EPC schedules.

The goal for the DSP project was to try to reduce the EPC schedule of a MST plant to 24 months. The EPC schedule consists of engineering, procurement, construction, and commissioning of the plant. The construction activities are the most expensive part. One potential way to reduce cost is compress the onsite mobilization of the construction activities to as short a window as practically possible without incurring excessive over-time and making sure crew sizes remain manageable. The DSP project set a goal of reducing the onsite construction and commissioning schedule to 12 months. This was accomplished in the mid 80's by Luz International Ltd. who was able to build most of the SEGS parabolic trough plants in under 12 months and built the last 80 MW plant in under 9 months. This schedule came at a price of both increased overtime labor costs, high costs for accelerated shipping of materials and components, and potentially lower quality construction. But, if done correctly, such accelerated schedules could help reduce project costs. The key is to make sure the plant is designed for rapid deployment and that everything is well engineered and planned well in advance. A 12-month construction mobilization is very aggressive for a tower plant. It would be difficult to achieve these schedule objectives with a single plant, but potentially second or third plants could achieve this goal. It is possible that key components like the tower and the molten-salt receiver will need to be redesigned with this type of schedule in mind.

S&L has prepared a level 2 schedule for the DSP plant that can be found in Appendix C. S&L developed a 34-month EPC schedule broken into 6 months of limited notice to proceed (LNTP) and 28 months of Full notice to proceed (FNTP). LNTP includes engineering for long lead items and procurement of long lead equipment. The goal is to minimize cost and commitments prior to financial close of the project. FNTP occurs after project financial close, and allows spending to occur as necessary, although typically the project prefers to delay spending to reduce drawing on the construction loan to reduce interest payments. Table 8 compares the current industry reference schedule for MST plants, the DSP goals, and the schedule developed by S&L for this project with a focus on compressing the EPC schedule. S&L believes their proposed 34-month schedule is a very feasible estimate. Based on the APS RFP schedule, the 34-month EPC schedule (6 months LNTP and 28 months of FNTP) is a feasible schedule for the APS project assuming the plant could achieve financial close 9 months after it receives the PPA.

Table 8 EPC Schedule Comparison

	Industry Reference (months)	DSP Goal Sched. (months)	S&L Level 2 Sched. (months)
EPC Limited Notice to Proceed (LNTP)	6	0	6
EPC Full Notice to Proceed (FNTP)	30-36	24	27
Total EPC Schedule	**36-42**	**24**	**33**
Construction Mobilization	30	12	28

Critical Path: In the S&L schedule, the supply, assembly, installation, and commissioning of the molten-salt receiver is on the critical path. If the receiver schedule is compressed, very quickly other elements such as the concrete tower, steam turbine, molten-salt storage system, and heliostat construction begin to dictate the critical path in the project. The amount of slack indicates how much schedule compression can occur before other items are on the critical path.

- Receiver design, piping supply, and panel supply (19 months, critical path)
- Receiver panel, tower piping installation (8 months, critical path)
- Tower foundation and tower construction (13 months, 1 month of slack)
- Turbine supply (18 months, 1.5 months of slack)
- Molten-salt storage (6 months civil, 14 months erection and melting, 2 months slack)
- Heliostats supply, field civil works, heliostat assembly, and commissioning needs to be carefully planned to fit the desired schedule.

To confirm the current schedule is possible, the next level of schedule detail needs to be added. This would likely mean breaking the schedule down for each system and subsystem. As the schedule is detailed out, it is very possible that other elements begin to fall on the critical path such as piping and insulation, electrical systems, instrumentation, and the control systems. The S&L schedule has made a good step towards achieving the overall DSP 24-month EPC schedule goal; however, they did not compress the construction mobilization period, and in fact it is currently longer than the EPC FNTP. Except for the tower foundation and collector field civil work there appear to be very few construction activities that need to be started as early as S&L currently has them scheduled. Thus, there is significant opportunity to delay most of the construction mobilization on site. New heliostat designs allow for the heliostat field to be installed in 12 months or less. Efforts should focus on developing a tower that can be delivered in significantly under 13 months. But even if that is not the case, a small crew could be mobilized to begin construction on the tower and do the other early works needed at the site.

The S&L schedule does not explicitly show shipping of materials and equipment. This is currently assumed to be included in the procurement schedule. It is important to make sure shipping is included, especially for major equipment like the turbine, heat exchangers, molten salt, and other equipment that may be coming from international suppliers. Costs will be lower if more efficient, albeit slower, transportation modes can be utilized.

Schedule Compression: The S&L schedule is based on a standard engineer, procure, construct (EPC) project model. This assumes a developed set of engineering documentation exists for the plant prior to financing of the project. Once the project is financed and the EPC is given full notice to proceed, a substantial amount of detailed engineering and procurement activities are kicked off. Because there is so much work to do, there is limited opportunity for optimization of the design and construction process. In this mode, each project is custom designed and built. To go to the next level of schedule compression, a different EPC model is required. A greater level of upfront engineering is required. Ideally, it is for a second plant of the same design where the experience from the construction of the first plant can be used to re-optimize the previous design, procurement, and construction practices used. The schedule for each system and subsystem needs to be reevaluated and integrated with the overall plant schedule. EPC needs to develop the schedule to make sure all aspects of the EPC schedule are modeled correctly. It will be important to work directly with vendors to see where purchase and supply of equipment and materials (like large bore piping) can be accelerated.

The following approaches have been identified for helping to accelerate the EPC schedule in power projects:

- Upfront engineering methods.
- Simplified design.
- Effective change control, project planning, monitoring and control.
- Improved manpower development and training.
- Parallel construction techniques
- Sequencing of contractors
- Modularization and prefabrication of materials
- Utilization of heavy lift cranes (specialization of construction techniques)
- Maximize working hours by multiple shifts or around the clock construction scheduling.
- Contract and staff incentives
- Strong industrial relations policies
- Optimized access around site and contractors compound
- Streamlining inspections and QA/QC processes
- Contingent procurement
- Coordination of inspection services and streamlining of documentation for QA/QC
- Improved information management
- Computerized project management scheduling

3.6 Capital Cost

3.6.1.1 EPC Cost Estimate

Sargent & Lundy developed a Class 3 capital cost estimate for the DSP plant.[4] Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. Class 3 estimates generally involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less significant areas of the project. We assumed the uncertainty in the S&L estimate was the mid-range of the uncertainty in a Class 3 cost estimate, or +20% to -15%. The S&L cost estimate uses a relatively large contingency due to the lack of detail in the cost estimate. The S&L cost estimate is shown in Table 9**Error! Reference source not found.**.

Table 9 Sargent & Lundy EPC Capital Cost Estimate for Arizona DSP Plant

	EPC Capital Cost $M	**% of Total Cost**
Heliostats	$91.9	14.8%
Receiver	$45.5	7.3%
Tower	$28.3	4.6%
TES	$72.9	11.8%
SGS	$33.2	5.4%
EPGS	$126.7	20.4%
Common Areas	$15.6	2.5%
Transmission Line	$4.2	0.7%
General Conditions	$64.0	10.3%
EPC Indirect Costs	$44.8	7.2%
Contingency	$92.6	14.9%
Total Cost	**$619.7M ($2700/kWe)**	

Owner's Costs - The EPC cost does not include owner's costs: land acquisition, water rights, permitting, project management, owners construction supervision, development fee, O&M mobilization and training, property taxes during construction, and initial insurance costs. These costs are on the order of 10% of the EPC cost.

3.6.1 Cost Reduction

The current analysis shows that with a 30% ITC the MST DSP plant is reasonably cost competitive with new fossil plants built in Arizona; however, it is important to find ways to further reduce the cost of the DSP plant to anticipate reduction of the ITC and to enable stronger competition with batteries and PV. There is an extensive body of knowledge focused on reducing the costs of building conventional power plants. Many of the lessons learned from the nuclear,

[4] DOE Cost Estimating Guide, DOE G 413.3-21, 5-9-2011. Appendix H.

natural gas, and coal power industries can also be applied to CSP plants.[5] These are all complex engineering, procurement, and construction (EPC) power plant projects. Currently CSP plants are often built as one-off projects and thus are expensive and take longer to build than needed. This section identifies many opportunities to reduce the cost of deploying MST DSP plants. The following options were considered for cost reduction to the baseline design:

- Lower cost heliostats,
- Cost reduction opportunities in the EPC of the plant,
- Reduction in the EPC schedule,
- Multiple plants built in a power park cluster,
- Supercritical CO_2 power cycle,

For each case, an analysis was performed to evaluate the potential for cost reduction.

Heliostats: In the near-term (the next plant constructed), new commercial heliostat designs will likely reduce the costs of heliostats from greater than \$150/m^2 to about \$125/ m^2. This is the cost used in the S&L cost estimate. Heliostat vendors confirmed this was a reasonable cost target for the project. We expect that in a few years, additional cost reduction will allow heliostats to reduce to \$100/m^2 or even lower.

Improved EPC: There are opportunities for improving the EPC costs of CSP plants through improved engineering practices, procurement practices, improved construction, improved construction supervision practices, use of advance controls and electronics, modularization, and prefabrication of systems. It is difficult to estimate the potential cost savings that might be achieved. We assume that a mid-range estimate of 5% reduction in total EPC cost.

Reduced EPC schedule: Reducing the project schedule will not reduce the direct costs and could result in increased labor costs for overtime. However, a reduced schedule should result in reduced indirect and project financing costs. These savings plus getting a return on investment sooner can be very attractive. The current EPC schedule of MS tower plants is about 36 to 42 months. It is important to shorten the construction period and make sure plants start up and achieve full output rapidly. These long construction periods and slow start-ups lead to increased interest costs during construction, and increased indirect costs for staff, equipment, insurance, and taxes, as well as delaying the point at which an asset can begin providing a return. The goal of this project was to attempt to reduce the overall EPC contract to 24 months and the on-site mobilized construction work to 12 months. Our rough estimate of the savings works out to about 4%. We think this underestimates the real value that would be gained by shortening the EPC, but it requires much more detailed information about the cash flow during construction and the specifics of the project financing structure to estimate the benefit more accurately.

[5] Capital Cost Optimization On Gas Fired Power Projects Through Standardization, http://www.projectcontrolsonline.com/Blogs/tabid/103/Entryid/4/Capital-Cost-Optimization-On-Gas-Fired-Power-Projects-Through-Standardization.aspx

Power park: There is extensive data to show that developing a standardized design and building multiple plants in one location (i.e. a power park) can result in substantial cost reduction from a single plant construction. Savings occur due to many factors, but potentially most important is that the cost incurred to build a first of a kind (FOAK) plant can be spread over multiple plants. Building multiple plants (units) in series allows cost savings in terms of shared engineering, reduced mobilization costs, learning that reduces construction cost, improved purchasing efficiencies and potentially better pricing on equipment, reduced construction supervision and administrative overheads. Plants can share infrastructure (control rooms and O&M facilities, water treatment, security, communications, and IT), spare parts, and O&M staff. Development and financing costs can be shared across multiple projects. This is a significant advantage over most CSP plants built today that are often one-off construction projects. Studies in the nuclear power industry have shown that building four plants at the same site can reduce the average cost of the projects by up to 40% over a single plant cost [6]. In our analysis, we estimated a cost reduction of 10% to 22% for a 4-plant DSP power park, based on a 16% capital cost reduction and a 35% reduction in O&M costs. The power park resulted in an overall 19% cost reduction.

Combined Cases: We combined the cost reductions for: mid-term heliostat, mid-case EPC cost savings, mid-case 4-plant power park, and reduced EPC schedule. The combined cost reduction was about 25%.

sCO_2 Power Cycle: Supercritical carbon dioxide (sCO_2) power cycles are likely many years from practical commercial deployment, but it is possible that one could be built today at the 10 to 50 MW_e scale for use with MST technology. Supercritical CO_2 power cycles offer several potential advantages for a solar peaker application. Although most people consider the potential for improved efficiency as the main benefit of the sCO_2 cycle, other attributes of the cycle may be more important for the DSP application. The sCO_2 cycle is more compact offering the potential for a very modular power cycle design that can be manufactured in a factory, skid mounted and delivered onsite fully tested and ready to operate after a short period. This minimizes EPC construction costs and reduces power cycle supply and delivery schedules. The modular nature of the power cycles means that multiple small power cycles can be used in place of single larger power cycles, improving the availability and flexibility of the plant. Because the system uses CO_2 instead of steam, the operation of the plant is more like that of a gas turbine than a steam cycle, allowing quicker starts, faster ramping, and potentially unattended operation. Finally, the plant can be designed to use no water. For purpose of this assessment, Solar Dynamics performed a screening study looking at the relative changes that might be expected from the baseline steam DSP plant compared to a sCO_2 DSP plant working at the same maximum molten-salt operating temperature of 565°C. This analysis is based largely on the results of the NREL/Echogen study that evaluated sCO_2 power cycles for use with CSP plants. The results of the analysis show that the sCO_2 power cycle could provide a modest cost reduction (7%).

This analysis simply shows that there is a possible advantage to the sCO_2 cycle. However, there is clearly significant uncertainty in these results. The costs could be much higher than the

[6] Reduction of Capital Costs of Nuclear Power Plants, Nuclear Energy Agency,

baseline. But the sCO_2 cycle could be an enabling technology by eliminating the need for water treatment at the site and maybe enabling a much quicker deployment of plants. However, the sCO_2 power cycle would have to overcome the FOAK costs associated with a new technology. These are likely to be a significant cost penalty for the first plant built.

Reduced Cost Cases: Two cost reduction cases are considered. The first is a reduced cost case for a single plant, the second for a power park of 4 plants. The reduced cost case assumes heliostat price is reduced 20% to $100/m^2, the tower cost is reduced 20%, there is a 1% reduction in contingency, and sales taxes are not paid on solar technology. We assume PV is used to provide parasitic power during the day instead of purchasing power from the utility, a 10% savings on O&M, and property taxes are only paid only on non-solar equipment. The power park case assumes an additional 20% reduction in capital cost and a 20% reduction in O&M costs.

Case	**Capital Costs**	**Owners Costs**	**O&M & Project Costs**
Baseline Cost	$642M	10%	37%
Reduced Cost	$596M	10%	31%
Reduced Cost Power Park	$480M	10%	32%

3.7 O&M Model

For the DSP to be cost competitive with fossil and battery plants, it is important to implement a very lean and efficient O&M plan. Solar Dynamics developed an O&M model for the DSP plant that is patterned after an approach that we have seen successfully used at operating CSP plants. Figure 14 shows the O&M organization chart for the DSP plant. This approach minimizes the amount of onsite staff and assumes a highly automated control system. The onsite personnel focus on production related activities, and preventive and predictive maintenance activities. Work conducted for major maintenance and outages are assumed to be contracted externally. The O&M costs are shown Table 10.

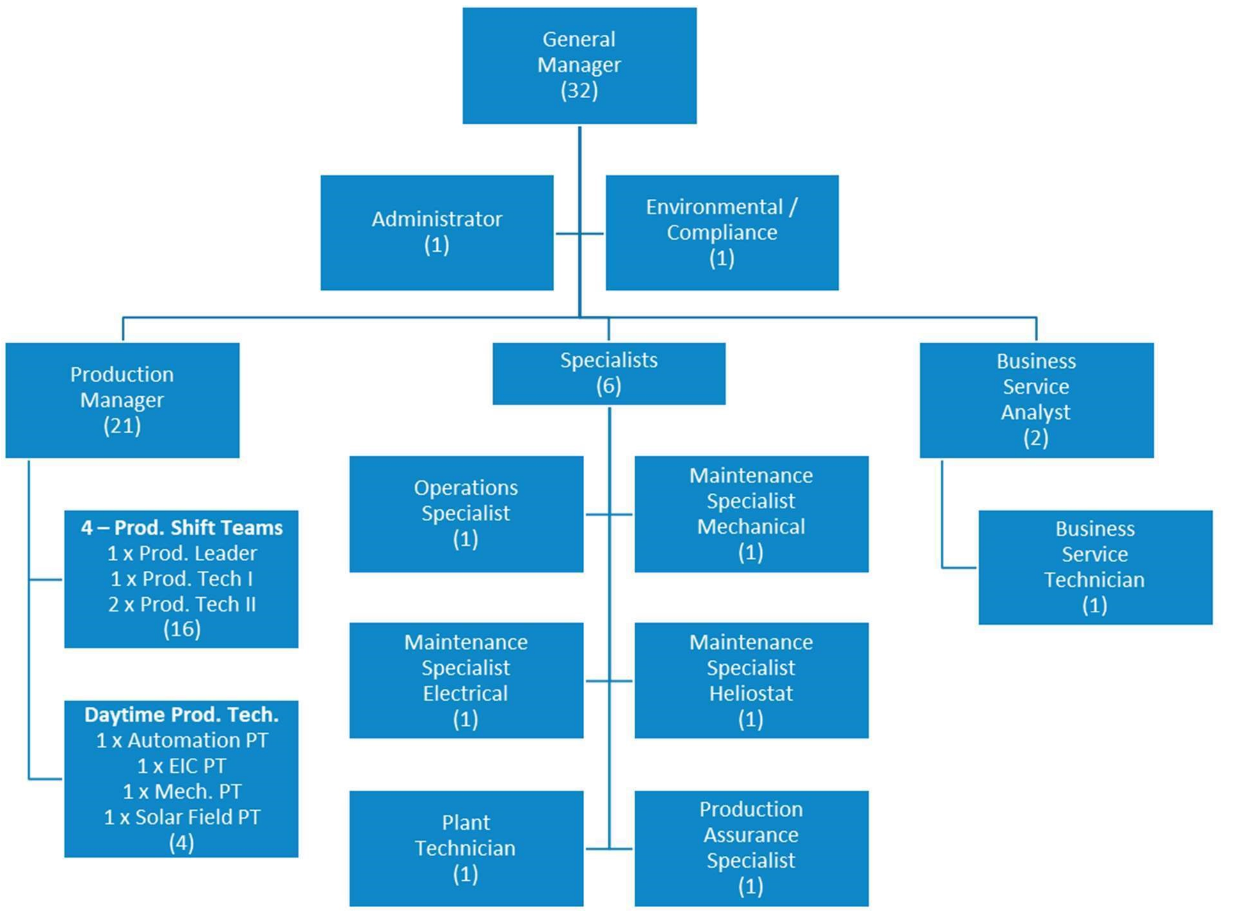


Figure 14 O&M Organization Chart

SolarDynamics

Table 10 O&M Cost for Non-Union DSP Plant

		DSP O&M Model $/yr	Scaled from Operating Plant $/yr
O&M Labor		**4,379,215**	**4,856,565**
	Operations Salaries & Wages	2,830,026	1,547,105
	Maintenance Salaries & Wages	651,993	1,877,564
	Plant Salaries & Wages	897,196	1,431,895
Maintenance Costs		**2,500,000**	**3,074,055**
	Solar Field Maintenance	550,000	526,614
	Power Block Maintenance	1,250,000	1,467,474
	Facilities Maintenance	100,000	270,968
	Total Major Maintenance	500,000	384,000
	Total Capital improvements	100,000	425,000
Total Operations Costs		**2,050,000**	**2,522,024**
	Service Contracts	1,450,000	1,093,182
	Water Treatment & Supply	600,000	1,359,860
	Vehicle and Equipment Fuel	0	35,082
	Utilities	0	33,900
Other Costs		**100,000**	**248,370**
Total O&M Costs		**9,029,215**	**10,701,013**
Project Costs		**4,750,335**	**3,345,899**
	Insurance	2,535,000	2,061,254
	Project Expenses	145,000	262,500
	O&M Fee	445,423	256,250
	Project Management Fee	698,912	765,895
	PPA/LGIA Letter of Credit Fees	426,000	
	DOE Loan Maintenance Fees	500,000	
Total O&M + Project Costs		**13,779,550**	**14,046,912**

Solar Dynamics also scaled O&M costs from an existing plant as a relative check. The results are shown in Table 10. The comparison shows the O&M assumptions for the DSP are at least in a reasonable range. Excluding plant insurance and other owner's costs, the O&M cost is about $9M/year including major maintenance and capital upgrades. The major differences between the two O&M models is labor costs, the cost of water treatment, and maintenance costs. The simplified water treatment approach assumed for the DSP accounts for the reduction in the water treatment costs. The organization approach accounts for the labor savings.

3.8 Financing

The Solar Dynamics team developed a detailed financial model for the DSP project in Arizona[7]. The model is a much more detailed financial model than the one available in SAM, as it allows for more detailed cash flows during development, construction, and operation of the project. However, the results of the financial model are only as good as the input assumptions. In this case the input assumptions are initial estimates based on the level of detail available to the Solar Dynamics team. The results should be considered indicative at this point. The new reduced corporate tax rate, 1-year depreciation, and other factors in the recent tax bill will have an impact on the cost of energy (or cost of capacity).

The model estimates the all-in capacity payment that would be required for the DSP plant Tolling PPA. Key baseline financing assumptions:

Financial Structure: Leveraged Partnership Flip
PPA: 30 years, 0% annual price escalation
Equity IRR: 10% (average of developer and tax equity)
Debt: Federal Finance Bank, 4% interest rate, 26-year debt term, 11% credit subsidy rate, DSCR = 1.4x.
Construction Loan: 24 months, linear, 80% debt.
ITC: 30%, 0% bonus depreciation
Depreciation: 5-year MACRS
Property Tax: Arizona, 1% and decreasing over time.
Sales Tax: Maricopa County AZ, 6.3%.
Federal Corporate Tax Rate: 35%

The DSP capacity price for the baseline financing assumptions is $276/kW-yr. This corresponds to an energy only PPA price of $207/MWh.

The APS RFP limited the length of the tolling PPA contract to 20 years. The table below looks at the change in pricing for shorter duration PPA terms. Reducing the PPA term to 20-year results in an 18% increase in the Tolling PPA price.

PPA Term Years	Loan Term Years	Tolling PPA $/kW-yr	% of Baseline	
30	26	$276	100%	Baseline
25	22	$293	106%	25-year PPA
20	17	$326	118%	20-year PPA

The ITC is due to reduce to 10% for projects that start construction in 2022. The table below looks at the impact of the ITC on pricing. Elimination of the ITC results in an approximate 24% increase in cost.

7 The DSP financial model was developed by Mr. John Costanzo who was involved in the financing and operation of the SEGS projects, Nevada Solar One, Solana and Mojave Solar CSP projects.

ITC Years	Tolling PPA $/kW-yr	% of Baseline	
30%	$276	100%	Baseline (30% ITC)
10%	$320	116%	ITC Reduced to 10%
0%	$341	124%	ITC Eliminated

Because of uncertainty in the Federal Loan Guarantee program we also consider commercial financing. This assumes the cost of debt interest rate of 5.5%, the DSCR is reduced to 1.3x, elimination of credit subsidy fee, add 2% loan fees, and the loan term is reduced. The table below shows the impact of switching to commercial financing with a range of loan terms. The main advantage of FFB financing is the longer loan term.

PPA Term Years	Loan Term Years	Tolling PPA $/kW-yr	% of Baseline	
30	26	$276	100%	Baseline (FFB financing)
30	26	$280	101%	Commercial
30	24	$285	103%	Commercial
30	20	$301	109%	Commercial
30	15	$326	118%	Commercial

Some states have policies that reduce or eliminate sales taxes and/or property taxes on renewable or solar power plants. Elimination of both property and sales taxes reduce cost by 8%.

Tolling PPA $/kW-yr	% of Baseline	
$276	100%	Baseline (includes Sales and Property Tax)
$267	97%	Eliminate Sales Tax (6.3%)
$262	95%	Eliminate Property Tax (1%)
$254	92%	Eliminate both Sales and Property tax

Finally, we make a first estimate on the impact that the new reduced corporate tax rate and 1-year depreciation will have on cost. The reduced corporate tax rate increases cost. This is counter intuitive, but we believe this is because it effectively raises the weighted cost of capital. The 1-year depreciation replaces the 5-year accelerated depreciation (MACRS). This results in a reduction in cost. Over all, the two changes appear to almost balance out. However, the details of the changes could be more important. The reduced corporate tax rate will likely impact the amount of tax equity available and the tax equity IRR. The change to single year depreciation will also be important for investors.

Tolling PPA $/kW-yr	% of Baseline	
$276	100%	Baseline (35% Corporate Tax, 5-year MACRS)
$283	103%	21% Corporate Tax
$267	97%	1-yr Depreciation
$279	101%	Eliminate both Sales and Property tax

Cost Reduction Cases: We evaluate the capacity payment for the different cost cases listed above.

Tolling PPA $/kW-yr	% of Baseline	ITC %	
$276	100%	30%	Baseline cost case
$231	84%	30%	Reduced Cost Case
$192	70%	30%	Power Park Case
$225	82%	10%	Power Park Case

3.9 DSP Capacity Cost Comparison

3.9.1 Fossil Plant Capacity Cost

The DSP plant is designed to compete head-to-head with a greenfield (new build) natural gas combustion turbine or combined cycle plant. To get a fair comparison between the solar and fossil technologies, the evaluation must include environmental externalities such as emissions, carbon mitigation cost, gas supply infrastructure costs; in addition to the capital and O&M costs.

The Cost of Generation (COG) model developed by the California Energy Commission (CEC) was used to evaluate the competing price from fossil plants. The COG model was developed and is maintained by the CEC to track the cost of generation for all new power technologies. The current version of the COG model can be down loaded at the CEC website [8]. The CEC has prepared a report documenting the use of the COG model and providing descriptions of the technologies included. The CEC report summarizes the cost trends for utility-scale generation resources that may be built in California over the next decade. These resources include solar, wind, geothermal, biomass, and gas-fired technologies. The COG model input assumptions account for trends in technology, permitting, construction, and financing costs for investor-owned, publicly owned, and merchant-owned generation resources. The model calculates the levelized costs necessary to provide the financial incentive for development [9]. The assumptions in the COG model are based on plants sited in California. Solar Dynamics has modified the assumptions in the COG model to reflect costs in Arizona.

Arizona Fossil Plant Assumptions

The cost goal for the DSP plant is to be able to offer an all in Capacity Price of $250/kW-yr. The all-in capacity price of the DSP plant includes: capital investment, taxes, off-line parasitics, fixed and variable O&M. DSP plant will be compared to a GE 7FA Frame combustion turbine (CT) and a GE LMS100 Intercooled Aeroderivative combustion turbine. The all-in capacity payment cost target for the CTs will include the capital cost of the plant, taxes, fixed and variable O&M, avoided fuel and emissions, including the valued of avoided carbon. For the APS comparison, the fossil alternative will also include a cost for avoided gas infrastructure provided by APS.

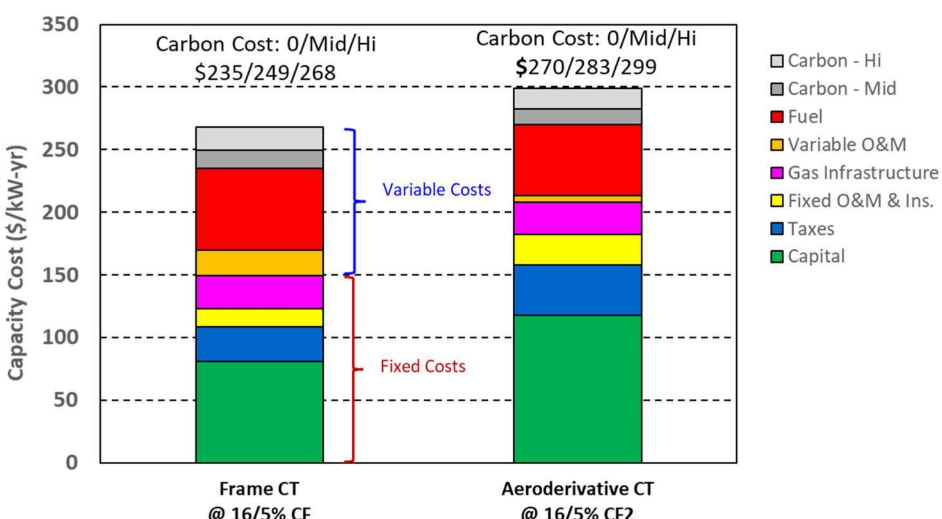
APS Assumptions:

- Used APS gas price assumptions per 2017 IRP. [10]
- Used APS carbon pricing starting in 2023 per 2017 IRP. [10]
- APS has estimated the heat rates for summer and winter operation. [11]
  - 11,000 MMBtu/kWh in Summer
  - 10,000 MMBtu/kWh during rest of year
- Capital cost of frame combustion turbine - $791/kW [12]

8 CEC COG Model Website: http://energy.ca.gov/2014publications/CEC-200-2014-003/
9 Estimated Cost of New Renewable and Fossil Generation in California (Final Staff Report), Publication Number: CEC-200-2014-003-SF, Publication Date: March 9, 2015
10 APS 2017 Integrated Resource Plan
11 Per email from Brad Albert (APS), 3/22/2017.
12 Western Electric Coordinating Council, Capital Cost Review of Power Generation Technologies, Recommendations for WECC's 10- and 20-Year Studies, March 2014.

- o APS provided an avoided gas infrastructure cost of $6-7M per year for the gas transportation needs associated with a 250 MW gas peaking facility. [11 **Error! Bookmark not defined.**]
    - $24-28/kW-yr.

Figure 15 shows the all-in capacity payment calculated for both frame and aero-derivative combustion turbines operating at a 16.5% annual capacity factor in Arizona. We show the cost for zero, mid case (reference), and high case carbon cost assumptions. The all-in capacity payments appear high because they include the variable O&M, fuel, and emissions costs. Without these the annual capacity payments would be $123/kW-yr for the frame CT and $182/kW-yr for the aero derivative CT. These numbers appear reasonable for new greenfield projects. The variable costs are levelized over the life of the plant, and include escalation of fuel, and emission costs. Thus, a lower all-in capacity payment could be achieved in year 1 if the capacity payment could escalate each year with inflation of the variable costs.



Assumptions:

1) The analysis uses the California Energy Commission cost of generation (COG) Model.
   Reference: CEC Report: CEC-200-2014-003-SD, "Estimated Cost of new renewable and fossil generation in California" May 2014.
2) The analysis is conducted for GE 7FA Frame and LMS100 Aero-derivative combustion turbines operating at an annual capacity factor of 16.5%.
3) Assumes 5% at 11,000 Btu/kWh heat rate and anything above 5% CF at 10,000 Btu/kWh (APS assumptions)
4) Uses Arizona capital costs from WECC TEPPC 2014. Uses operating costs from IEA AEO 2017.
5) Fuel and Carbon cost assumptions from APS 2017 IRP.
6) Gas infrastructure based on APS assumption of $6-7M/yr for 250 MW plant.

Figure 15 Arizona Capacity Cost of Frame and Aero Derivative Combustion Turbines

3.9.2 DSP Capacity Cost Comparison

Figure 16 shows a comparison of capacity payments for conventional combustion turbine peakers and the DSP plant. We use the mid carbon case for comparative reference for the combustion turbines. The DSP Baseline Cost Case uses the Sargent & Lundy cost estimate and Solar Dynamics financing assumptions. This provides a reasonable estimate for a next plant built. The baseline is competitive with the aero derivative CT, but about 10% more expensive than the frame CT. The cost reduction case assumes somewhat more aggressive cost assumptions (defined above). In this case the DSP is also competitive with the frame CT. Finally, the power park case assumes significant cost reduction due to the economies in building of multiple plants at the same site. The resulting all-in capacity price is very attractive; however, this case assumes a 30% ITC which may be reduced or eliminated. This case also includes the lower costs of the Cost Reduction case. The final case assumes a power park with a 10% ITC. Assuming these cost reductions are feasible, the final case is competitive with either combustion turbine.

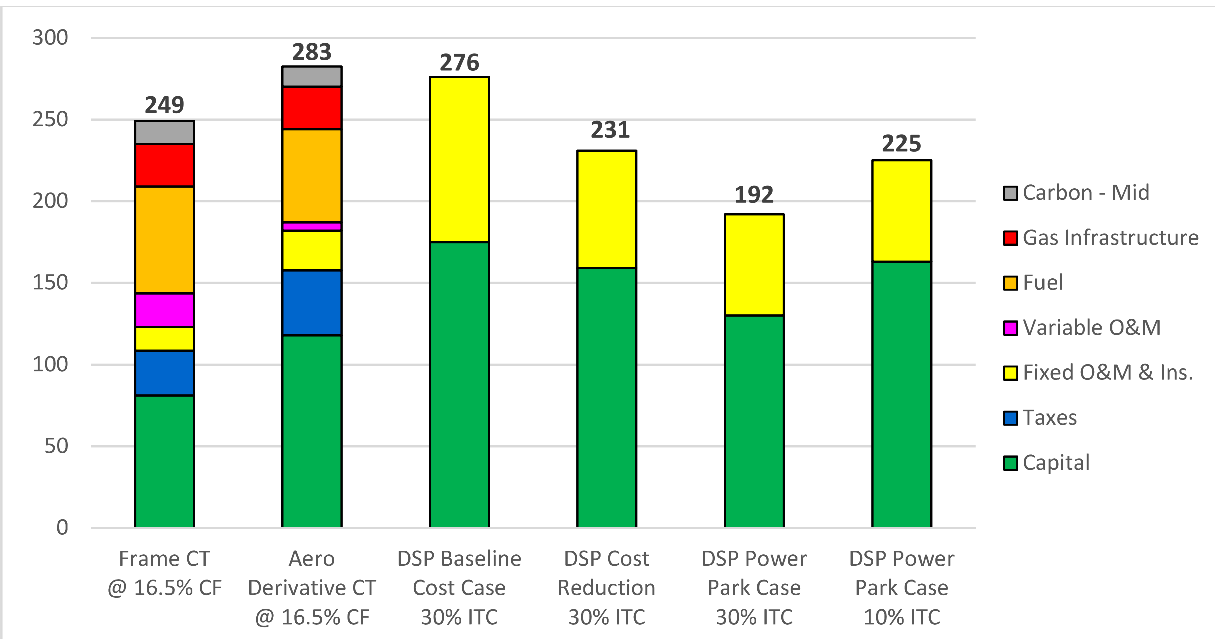


Figure 16 Capacity Payment Comparison of Combustion Turbines and DSP Plants

3.9.3 Cost Comparison: Battery + PV

Solar Dynamics has received feedback from many developers that we should also compare the DSP to batteries + PV. We have found it is difficult to make a good comparison because very few commercial utility scale battery projects have been built and it seems that many costs referenced in the literature are based on forward pricing assumptions. A 2017 report by EPRI[13] was chosen to provide the best basis for a cost comparison with batteries. EPRI report provides a detailed breakdown of costs for a 4-hour utility scale (50-100 MW) lithium ion battery storage system. The report gives a range of costs for the system. We have used the EPRI data and extrapolated it to a system that would compete with our APS 5-hour storage DSP plant. To the EPRI battery system we add 1 additional hour of battery storage, add the cost of PV to charge the storage (assumes a 0.7 PV solar multiple). The results show:

EPRI 2017 Battery + PV Cost Estimate ($)	Low	High
4-hour battery system	1600	2700
1 extra hour of batteries	200	300
PV system ($1/W-$1.2/W @ 0.7 SM)	700	840
Total Cost ($/kWe)	**$2500**	**$3840**

CSP DSP cost estimates: $2800/kWe baseline, $2600 reduced cost, $2100 power park.

The comparison only looks at a capital cost comparison. Based on this the CSP plant appears to be at the lower end of the PV + battery cost range based on the EPRI data. However, the analysis does not consider O&M costs, lifetime and replacement cost of the equipment, technology risk, performance of the plants over time, or financing and development costs. The PV battery system is also much more modular/scalable and likely requires much shorter duration to construct. Many developers like the simplicity that PV plus battery option offers. A more detailed comparison is needed to fairly compare the results.

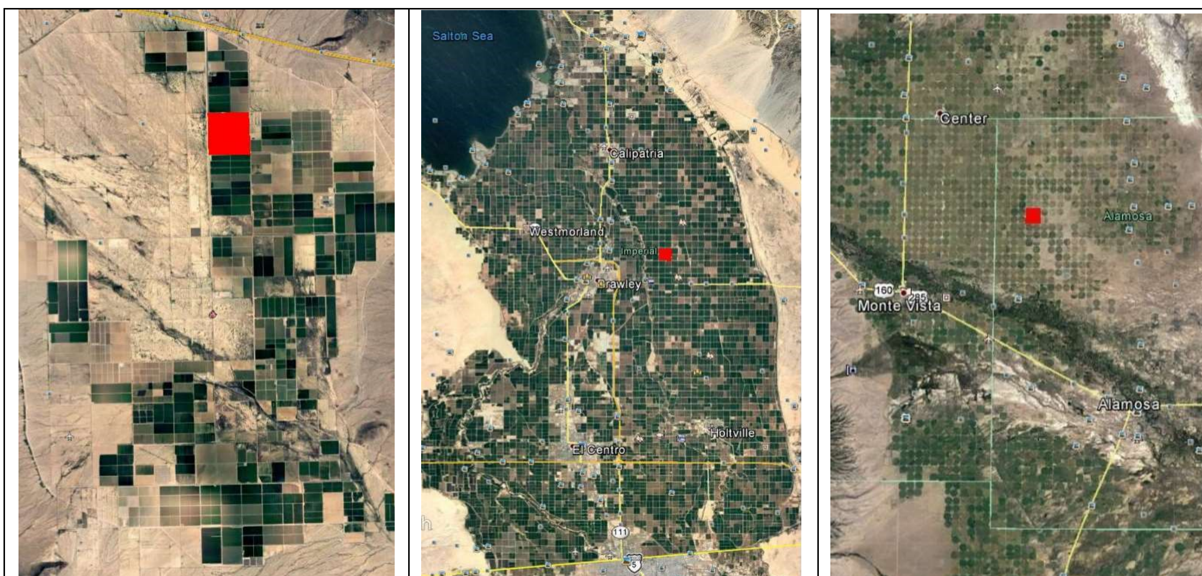
[13] G. Damato and E. Minear, Energy Storage Cost Summary for Utility Planning: Executive Summary, EPRI 3002008877, Nov 2016.

3.10 DSP Permitting Improvements

Square Mile Plant

Land in the western U.S. is laid out in sections. A section is a square parcel of land, one mile on side (one square mile or 640 acres of land). Although not all sections are exactly a square mile, they are generally relatively close. Sections are typically subdivided into smaller parcels, but most county roads and utilities are arranged such that they run between sections rather than through the middle of sections. As a result, there are many square mile sections of land available in the west that have no roads or utilities crossing them. Once you start to look for larger parcels, they often have county roads crossing them. It becomes much more difficult to find a parcel of land that is 1.75 miles by 1.75 miles, the size of the Crescent Dunes power plant. For this project, we limited the plant size to a square mile. This worked out satisfactorily because we were able to get a solar field with a thermal rating of approximately 400 MW_t, which in turn was a good size for the maximum size SST900 steam turbine from Siemens (250 MW_e).

To explore this approach, we conducted a siting study in Arizona. In the regions we were considering we only found two potential sites that were 2 miles by 2 miles on a side. But we found over 20 potential sites that were 1 mile by 1 mile on a side. We determined that the square solar field had less than a 1% impact on the cost of the plant relative to an optimized 400 MW_t with a circular solar field layout. The ability to standardize the plant design, simplification of permitting, and the increase siting options provide a substantial benefit for the square mile field concept over the optimized circular layout. Figure 17 shows examples in Arizona, California, and Colorado of land suited for square mile plant sites.



Arizona	California	Colorado

Figure 17 Example Square Mile Land Sections

Avian issues

Solar Dynamics worked with NREL to integrate the best avian practices into the conceptual design of the MST DSP plant. Key among these are to minimize concentrated flux above the solar field for heliostats not actively focusing light on the receiver that is, are in standby operation. Experience from Ivanpah and Crescent Dunes seems to indicate that heliostats in standby that create high flux zones are the most dangerous to birds. NREL/SNL have developed several operating modes to reduce high flux zones above the solar field. Solar Dynamics plans to use the approach that reflects light vertically when heliostats are in standby. This requires heliostats to have an acceptable tracking (slew) speeds to minimize performance losses. Importantly, this approach is also good for addressing aviation glint/glare issues.

The other major issue is bird impacts. It appears that impact deaths remain at a significant level. This relates to birds being injured by running into mirrors or other structures. Solar Dynamics is considering a number of potential options that could reduce impact deaths. Commercial buildings have had success with patterns on windows to allow birds to better detect the glass. Figure 18 shows an example of windows at NREL's ESIF laboratory that include a pattern of paint dots on the glass to help birds see the glass. The dots occupy approximately 2% of the glass area. Further, there may be other approaches that could reduce impacts. Birds apparently can see in the ultraviolet region. Potentially patterns could be used that only block light in the ultraviolet region and thus only impact a small portion of the solar spectrum. Alternatively, bright painting around the perimeter of mirrors or other approaches could help birds be more aware of mirrors.

Although Ivanpah and Crescent Dunes have chosen to leave the natural vegetation in the heliostat field. Solar Dynamics is considering the possibility of removing the native vegetation from the solar field. This removes the habitat for animals, making the site less desirable and resulting in fewer birds on site and fewer fatalities. Removing on-site vegetation will also aid in inspections looking for injured birds. Additionally, we are looking at approaches to reduce the evaporation ponds on-site. Ponds tend to attract birds, and birds are occasionally trapped in the ponds, resulting in additional avian fatalities.

.

Figure 18 Windows with Avian Deterrent Patterns at NREL ESIF

Visual Impacts of Molten Salt Towers

As molten-salt tower technology looks to increase adoption and be deployed in more locations, the question of the potential visual impact of the operating plant to surrounding communities becomes more important. Although the question has not generally been a major factor in the design and siting of plants in the past, it becomes a potential important topic for future plants. The Ivanpah plant on the California-Nevada border has received much attention in part because it is near a major interstate highway and is viewed by many people. Public reaction to the project is mixed but some have raised concerns over the visual impact to the natural desert vista. For example, this is an issue for Arizona at the several locations quite suitable for DSP plants. Solar Dynamics is looking at two approaches to address the visual impact of the tower. The first is to evaluate potential sites to determine how visible the tower is to surrounding communities. The goal is to identify sites that minimize the visual exposure of the tower, in essence to hide the tower from view. The second is to reduce the visual intensity of the tower, as discussed below. Of course, there will be varying individual reactions to the view of a power tower. Like vast arrays of wind machines, some will favor their contribution to renewable energy and accept the impact on the view, while others will not want them in sight of highways or towns.

Viewshed Analysis

Solar Dynamics has prepared a viewshed analysis to determine where the tower and receiver are visible. This can be used to determine where the illuminated receiver can be seen and where it cannot. The illuminated receiver is obvious and visible from a great distance. We have prepared the viewshed analysis for one of the sites for the APS DSP plant. Figure 19 is a Google Earth image of the area surrounding one of the proposed sites for the APS DSP project. The viewshed of the tower/receiver is outlined in yellow. The Analysis assumes a tower height of 621 feet. The Phoenix metro area starts about 40 miles east of the site. Note that the mountains and hills near the plant block the view of the tower from the Phoenix Metro area, making the tower is only visible to some of the smaller outlying communities.

Two potential issues exist for the proposed location. First, the plant is only a couple of miles from the I10 interstate highway. The tower will be in drivers' line of site for about 25 to 30 miles as drivers approach the tower from either direction. The second issue is that the Phoenix International Airport is 60 miles due east of the tower. The runways at the airport run east/west. The tower will be visible to planes approaching from the east and potentially for planes in the landing pattern before they turn back to land to the east. The tower might also be visible to planes taking off to the west once they reach a certain elevation. Luke Air Force Base is only 40 miles from the tower, but a mountain is between the base and the tower. The tower is likely not a concerning issue for Luke AFB.

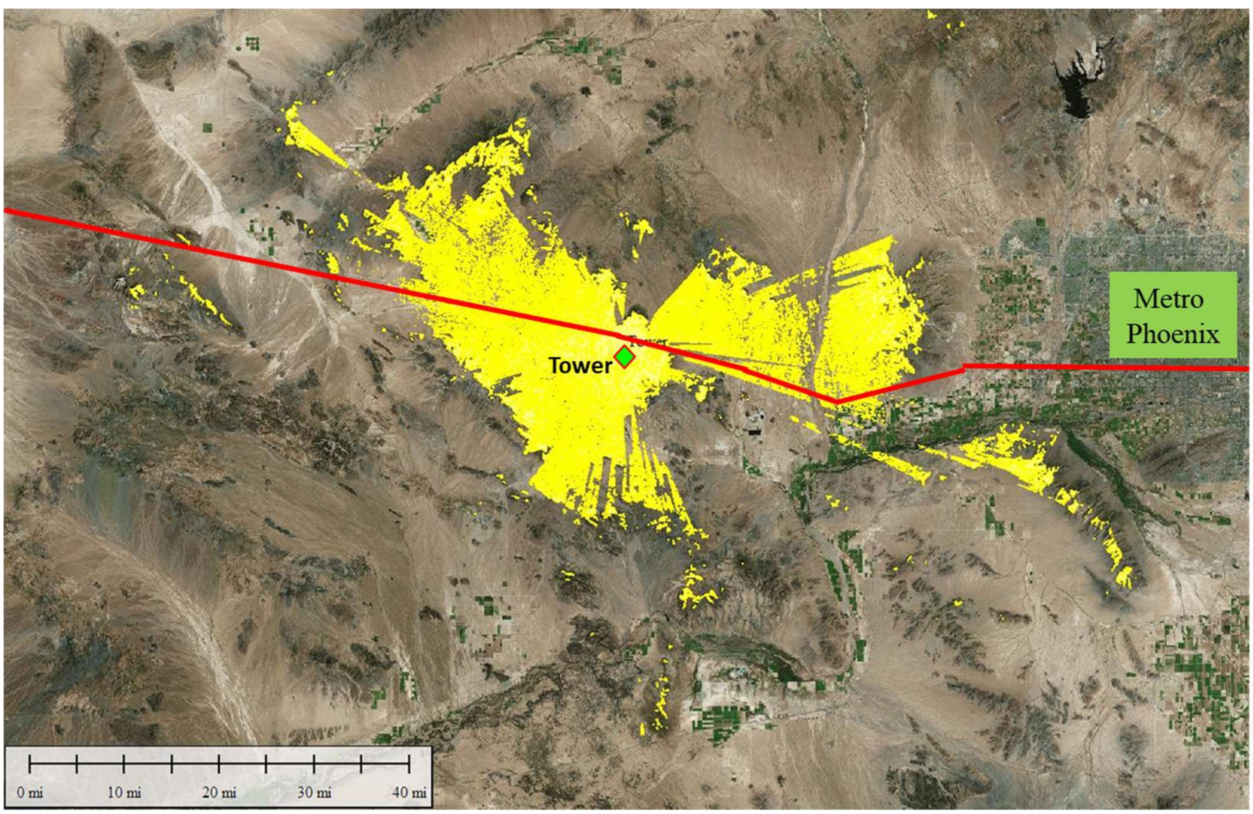


Figure 19 Viewshed for MS Tower in Harquahala Valley

Tower Brightness Mitigation

The visual impact of the illuminated tower can be an issue for siting of new tower plants. The DSP plant would be sited in a location where it will be visible to many people daily. Can the visual impact of the tower be mitigated such that it is less obtrusive?

Figure 20 shows an image of the Gemasolar MST plant in southern Spain. The brightness of the tower is significant when one is near the plant. It can be almost painful to the unprotected eye. However, a closer examination of the tower and re3ceive in Figure 21 shows that the brightness of the molten-salt receiver is less than the brightness of the spilled light on the tower above and below the receiver. The brightness of the receiver cannot be helped but are there opportunities to reduce the brightness of the tower near the receiver and thereby reduce the overall visual impact of molten-salt tower plant.

Figure 20 Gemasolar Molten-Salt Power Tower (Spain)

Figure 21 Receiver & Tower Brightness

Solar Dynamics worked with Tim Wendelin of NREL to determine the flux levels of concentrated light that misses the receiver and hits the tower above and below the receiver. The flux levels then convert to illumination brightness. This illumination could be reduced if it is possible to use darker materials or other approaches to reduce the apparent brightness. The work with NREL is documented in Appendix D. The analysis looked at how heliostat accuracy, heliostat size, receiver oven and tower reflectance effect the apparent brightness of the tower. The analysis confirmed that the two best approaches for reducing tower brightness is to reduce the reflectance of the tower and receiver ovens, and to improve heliostat optical accuracy. Reducing the reflectance of the tower results in thermal loading on the tower. Solar Dynamics evaluated a modified transpired collector concept to actively cool the tower, shown Appendix D.

4 Significant Accomplishments and Conclusions:

4.1 DSP Technology Readiness Evaluation

The MST DSP plant utilizes many features that are based on the current state of the art for MST Plants. The solar side of the plant is largely a conventional molten-salt tower plant. The salt storage is standard, though slightly oversized compared to more traditional MST designs. The power cycle side of the plant is optimized for more flexible operation, faster starts, quicker ramping, improved availability and reliability of starts/operation and the ability to maintain net output at elevated ambient temperatures. From a technology standpoint, the MST DSP plant is ready to be commercialized.

4.2 Utility Survey

There has been no new CSP projects sold in the United States during the last 7 or 8 years due in large part to the dropping price of PV and the lack of the markets to value the benefit of storage. One of the main goals of the DSP project has been to identify a real market opportunity for CSP technology today, and therefore the DSP plant concept has been developed based on a perceived need in the evolving power marketplace. To assess whether the DSP plant makes real sense in today's market, we sought and received feedback from Southwestern utilities on the concept. MAI and Solar Dynamics prepared a survey on the DSP plant concept to formally get feedback from utilities, and MAI identified a number of utilities who agreed to participate in the survey. In addition to the survey, the utility participants listed below received a copy of an overview presentation on the DSP plant concept and, in some cases, a discussion via a Skype meeting presentation.

- Arizona Public Service (APS)
- Electric Power Research Institute (EPRI)
- NV Energy (NVE)
- Pacificorp
- Sacramento Municipal Utility District (SMUD)
- Salt River Project (SRP)
- Southern California Edison (SCE)

MAI received responses from four utilities: APS, SCE, SMUD and a fourth utility that preferred to not be identified. Highlights from the responses are summarized here. A compilation of the questionnaire questions and responses are presented in Appendix E at the end of this report.

Utility views on the market outlook:

- Need for peaking resources is high in the three states with responses. In Arizona it is the "only resource" needed and the only resource that they see exporting to California. In Nevada the need is "high" and in California it is a "large and growing" need. There is a solid consensus that the market for peaking – carbon-free and/or for less dependence on natural gas, diverse, flexible and fast – will grow.

- DSP's competition in next 5-10 years in California are batteries, pumped hydro, PV, wind and geothermal, while in AZ it is with PV+Batteries and with existing and/or new more efficient simple cycle plants.

DSP must meet these needs:

- The utilities understand the DSP application and MS technology. They want to see at least one large scale plant working, ideally for a couple of years with performance data, and if economic payoff is promising, may be willing to take more risk. DSP's most important challenges are cost and maturity. DSP must cost compete with PV+Batteries, simple cycle units, more efficient and lower cost thermal units (if carbon does not limit that) and the higher risk of new technology. Owners are needed with enough financial resources to back the plant and to keep it at a high availability. Lenders must see it as a valuable investment. To add DSP generation, it must be cost competitive, reliable, dispatchable, flexible, eligible for RPS credits and be scalable. A DSP plant must be able to compete in cost and performance with today's and tomorrow's PV+Batteries.
- Fast up and down ramps (10%/min) and startup (30 minutes to full load) – some utilities do not need all of these as they have other resources that do that, but some do. A need to operate in automatic generator control mode. A DSP plant must have 95-98% availability.
- DSP can meet those needs only if it is reliable and competitive with other options and especially, in future, if it is competitive with PV+Batteries. Reliability can be proven anywhere (overseas OK) but will need data to back up claims.

Cost comparison:

- It is appropriate to compare capacity cost of DSP to capacity cost of a NG peaker, as that is what it will be replacing.

Procurement:

- DSP will be procured by a PPA after competitive solicitation which will include an obligation for performance. A performance wrap is needed but PPA will provide incentives to assure that utility and owner's interests are aligned. And for first units, it will need backing of the regulator and ISO. The PPA must likely be 20 years (or 25 in some cases). A Tolling agreement is not likely with some utilities but possible with others. So, some may have an energy price PPA. A build-own-operate-transfer development not likely in competitive markets.
- Permitting will be challenging but maybe not more than any other power plant and public reaction could be significant.

Outreach:

- Outreach is essential to the ISO and regulators to create a partnership, and in CA where the market need is and will be greatest, must make the case that DSP is cost competitive.

4.3 Developer Survey

MAI and Solar Dynamics reached out to approximately 20 organizations we thought might be interested to learn more about the DSP plant concept, and who might have some interest in development of commercial projects. Skype meetings were setup with the nine development organizations listed below. A presentation on the DSP plant concept and market analysis was shared with each company followed by a general discussion on the DSP concept[14].

- Brookfield Renewable Partners
- BrightSource Energy
- DONG Energy
- Duke Energy
- EoN
- Merced Capital
- NextEra Energy
- Tenaska
- Total

The following summarizes the feedback we received from these meetings.

Summary of Developer Discussions:

- Most were familiar with CSP, but initially thought it had no currently viable market.
- Most were interested in the DSP concept.
- Some questioned if APS will purchase new capacity in 2017 or just purchase existing merchant capacity.
- Some entities were concerned this was a one-off opportunity.
- Most thought the major competition to be batteries & PV in the future.
- Some were strong proponents of PV + batteries, others were battery skeptics.
- Some believe that battery prices will drop significantly over the next several years and some don't.
- CSP Technology – a few recent plants have not performed well; are expensive, complex, and take a long time to plan, develop, finance and build.
- Financial institutions were also cautious of financing battery projects.

We were looking to see if any developers might be interested in responding to the APS 2017 Peaking Capacity RFP. Many of the developers seemed interested in the idea but the APS RFP required too quick of a turnaround. Developers already have budgets that are planned, and they cannot change and start something new, unless it is very compelling. Most developers seem committed to the PV + battery approach, although more as an incremental battery add on to a PV project rather than building a DSP project with batteries and PV. It will take time to groom new set of CSP DSP developers. Now that the study is complete, there may be new opportunities to garner interest in an APS 2018 Peaking Capacity RFP and similar opportunities in California.

[14] Morse Associates Inc. coordinated the survey of developers for this project.

Market Challenges Facing CSP:

- There is a perception that PV + Batteries are declining in cost and increasing in performance, so why invest in DSP?
- There is currently ample natural gas capacity that is still available at low cost and acceptable carbon costs.
- In most cases, the market does not value capacity or ancillary services from a renewable plant.
- The CPUC may ask utilities to buy 9 GW more renewables to use the ITC, but no groundwork had yet been done to maximize this opportunity for CSP.
- There is a lack of awareness of performance of CSP+TES and specifically of the potential of a DSP type plant.
- The poor start up experience of recent CSP tower projects, while limited, adds to perceived risk of new projects. The startup operation of the Noor III project in late 2018 and 2019 may go a long way to dispelling that concern.
- CSP is almost never mentioned as an option when any major event happens, like closing Diablo Canyon and Navajo, or rejection of the Ellwood NG peaker or the gas storage plant closure in California.

4.4 DSP Plant Technology Roadmap

The following represents a preliminary technology roadmap for the MST DSP plant concept.

Market

- The APS 2017 Peaking Capacity RFP represented a real market opportunity for the DSP plant. APS is expected to continue annual RFP's for new capacity.
- California represents a large market opportunity as they move towards more aggressive carbon reduction plans and they look at replacing current once-through cooling plants with renewable options instead of NG plants. DSP plant appears to be a viable and important option to meet California's need for peaking capacity, though other configurations of CSP in general do not currently appear to be considered as an option in CA. More outreach to key stakeholders in CA is to be needed to make sure DSP is considered as a viable option for future requirements.
- Other states like Nevada and New Mexico could represent opportunities if they raise their RPS to 80% by 2040 as currently under discussion.
- More aggressive carbon reduction plans could call for higher capacity factor DSP plants than the design optimized for Arizona.
- The DSP plant needs to compete head-to-head with new natural gas peaker. With the 30% ITC, 30-year PPA, and Federal Loan Guarantee financing the DSP appears to be on economic parity with new NG peaker, assuming current gas pricing and carbon cost assumptions.

- It is generally assumed that DSP will also need to compete with batteries + PV. Although there is a general perception that batteries and PV will eventually be cost effective, there the uncertainty is large.
- It appears that MST DSP technology needs 20-30% cost reduction to be competitive past 2020 due to the phasing out of the 30% ITC.

Operational Characteristics

- With appropriate design and equipment selection, it appears clear that DSP plants can meet the operational requirements needed for flexible generation.
- Many current CSP trough plants are operating very well, e.g., Genesis, Mojave Solar, Noor I and II, and Bokpoort. Current CSP tower plants have mixed operational records. Industry needs to demonstrate the availability, reliability and performance of MS tower plants that meet the expectations of the financial community.

Technology

The DSP plant uses conventional molten-salt solar tower technology. The DSP plant represents a different optimization in sizing between the solar field, thermal storage, and power cycle rather than any fundamental change in technology. The main difference is that the power plant has been optimized for more flexible operation and fast start-ups. However, a number of technology issues should to be addressed to enable commercialization of all MST technology.

- Reliability, Lifetime, Performance, and O&M Costs – There is need for public information on the reliability, lifetime, performance, and O&M costs of the solar and power plant equipment in molten-salt tower plants (heliostats, receiver, TES, SGS, EPGS). This data is currently not made public, but transparency would add considerable to the rapidity of reaching a mature technology. Much information was made public on parabolic trough technology by the SEGS plants, and that significantly helped the technology to evolve to fix reliability and lifetime issues. The same is needed for MST plants.
- An area that appears to need serious attention in CSP projects is strong QA/QC in major equipment procurement, installation, and commissioning.
- The emphasis on lower cost rather than extended strong performance harms the operation of CSP plants and needs mechanisms to bring these conflicting issues into more balance. This is a problem if the EPC has sole control over procurement.
- The DSP plant proposed for Arizona assumes hybrid (parallel wet/dry) cooling. For a DSP plant, the ability to maintain capacity (MW_e output) during hot summer afternoons is critical. A wet cooled design would have been preferred from a performance standpoint and likely from a cost standpoint. However, a dry cooled design is preferred from a water savings standpoint. The hybrid cooled case reduced water consumption by about 60% but comes at a higher cost. More analysis is needed to determine the best overall configuration. In cooler climates, the dry cooled option would typically be preferred.
- For tower projects the hot tank is subject to more failure potential due to its high temperature. It is important that the resolution and solutions to potential hot tank failures

be evaluated, and that the question of stress-relaxation cracking in tower systems be addressed.

- Heat tracing, piping and quality of insulation continue to be problems in some operating plants and can be improved in future tower projects.
- Development of more robust, high performance and cost-effective receiver selective coatings are needed for improved lifetime and performance.
- Mirror washing continues to be an important O&M cost. Reduction in mirror soiling rates and mirror wash costs is warranted.
- O&M cost needs reduction. Design improvements, automation, improved O&M systems, and other approaches are needed to reduce O&M costs and improve plant availability/reliability/performance.
- DSP plant designs should consider the possible integration of batteries and PV to improve overall project economics. Specifically, batteries for improved generation and ancillary services and PV to reduce internal off-line consumption, i.e., not for external generation.

DSP Plant Cost Reduction

The DSP needs a 20 to 30% reduction in cost to be competitive with gas plants when the ITC goes away.

- A significant effort is being focused on decreasing heliostat costs. Although this is clearly important, especially for baseload MST plants, it has a relatively small impact on the DSP plant. For example, reducing heliostat cost from $125/m^2 to $50/m^2 would reduce capital cost by about 10%, whereas for a baseload plant, this same change could be a 25% reduction in capital cost.
- After heliostats, the steam generator, receiver, and tower are the next most expensive equipment in the plant (even more than the turbine). Because these tend to be somewhat custom designs for the DSP plants, there is likely significant opportunity for cost reduction.
- Advanced storage tank concepts are being considered for high temperature molten-salt concepts. Some of these concepts might be applied to nitrate salts. Internal insulation could possibly be used with carbon steel to eliminate the need for a stainless steel hot salt tank. Potentially other low-cost approaches should also be considered for salt tanks.
- Design – Engineering can represent about 5% of the plant cost. There are a number of opportunities to improve the design of the plant in ways to reduce costs. Typical projects wait until financial close to start detailed engineering. As a result, there is limited time to iterate on the plant design and optimize each subsystem design. Early design or developing a standard design can allow for subsystem optimization to a much greater level than normally possible. Implementation of modular systems and manufacturing can allow sub systems to be built and tested in factories before they show up on site. Further, one-off designs add considerably to the design costs.

- Development of power parks represents a significant opportunity for cost reduction, potentially 10 to 20%.
- Reducing the EPC schedule saves EPC and owner supervision and overhead costs, equipment rental costs, insurance, interest during construction, and also potentially reduces debt interest rates and cost uncertainty.

Schedule Reduction

- To significantly reduce the EPC schedule, it will require a significant amount of engineering and work with vendors. Key focus areas need to be in the design, supply, erection, and commissioning of the following systems: receiver, tower, steam turbine, molten-salt storage, and heliostats. All major systems will need to be reviewed and optimized to meet more aggressive schedules, especially: electrical/switch yard, power cycle steam generation/feedwater/condensate system, and the DCS, instrumentation and controls.
- It takes one to two years to develop a project and permit it. This is a long time to work at risk in a competitive environment. Pre-permitted sites or zones could help solve that problem and allow DSP plants to get permitting much quicker. This is an approach that has been used internationally with success.

Appendices:

Appendix A – NREL Value of CSP Plus TES Update

Appendix B – DSP Plant Design Drawings

Appendix C – Sargent & Lundy DSP Plant Conceptual Level 2 EPC Schedule

Appendix D – Tower Visual Impact Mitigation

Appendix E – Survey of Southwestern Utilities

Appendix A – Energy and Capacity Value of CSP Plant Configurations

Prepared by: Janna Martinek, Jennie Jorgenson, and Mark Mehos

Jorgenson et al. previously evaluated the operational and capacity value of various CSP plant configurations using a production cost model (PLEXOS) with a database of generators within CAISO and surrounding areas under a future 40% renewable portfolio standard [1]. This analysis simultaneously optimized the dispatch of the entire fleet of generators to minimize total production cost and assessed the value of the CSP plant based on avoided costs including fuel, variable operations and maintenance, emissions, and startup/shutdown. The analysis indicated an increase in CSP plant value with a decrease in solar multiple; however, only CSP plants with a solar multiple of 1.3 or higher were considered. Here we utilize electricity prices from the same base case PLEXOS model and consider both the original configurations and new proposed DSP plant configurations using a price-taker approach. While the specific set of electricity prices was taken from a single region (Southern California Edison), prices showed essentially no differences between regions within California. The price duration curve and seasonal-average daily price profiles are shown in Figure 22. Values for 13 hours were capped at $500/MWh to minimize the impact of any artificially inflated prices generated by PLEXOS as a result of numerical penalties in the optimization model.

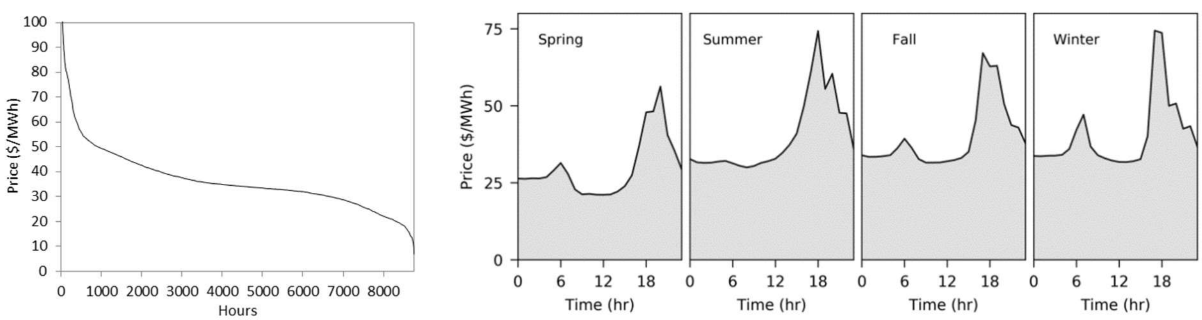


Figure 22 . Price duration curve and seasonal-average electricity price profiles

The price-taker model employed here is the dispatch optimization module of the SAM molten salt power tower (MSPT) model [2]. The dispatch optimization module is designed to maximize CSP plant revenue within operational constraints and includes cost penalties associated with receiver startup, power cycle startup, and power cycle ramping. A subset of design and operational parameters are specified in Table 11. All configurations utilize an identical solar field, and thus a smaller solar multiple corresponds to a larger power block. Parameters governing power cycle operation and startup are set to those used by Jorgenson et al [3] for consistency with previous analysis. Simulation parameters not specified in Table 11 are set to the SAM MSPT default values. The plant is situated in Arizona at NSRDB node 257870 and simulations utilize 2006 weather data for consistency with the loads, variable generation profiles, and electricity prices in the PLEXOS model.

Table 11 Simulation parameters

Parameter	Value
Receiver design point thermal power	395 MW_t
Cycle design point efficiency	0.424
Cycle design point ambient T	45°C
Power cycle startup time	0.2 hr
Fraction of thermal power required for power cycle startup	0.2
Power cycle startup cost	$10/MW/start
Variable operation and maintenance cost	$1.1/MWh
Cycle minimum operational fraction	0.20
Cycle maximum operational fraction	1.0
Thermal storage capacity	3 - 15 hr
Solar multiple	0.5 – 2.7
Turbine gross capacity	335 - 110MW_e

We consider two sources of revenue available to the CSP plant: net revenue from electricity sales and capacity value. Similar to the approach taken by Jorgenson et al. [1] and Madaeni et al. [4], we estimate capacity value using plant dispatch during hours with the highest net load (load – solar and wind generation) as a proxy for dispatch during hours with the highest loss-of-load probability. The capacity value is computed from the product of the turbine capacity, the annualized capacity cost of a new combustion turbine in California ($150/kW-yr or $190/kW-yr) [1], and the average capacity factor over a subset of the highest net load hours, divided by the annual electricity production from the CSP plant.

Dispatch optimization within the price-taker model only directly considers revenue from electricity sales, and thus the CSP plant has no intrinsic incentive to generate electricity during hours with high net load unless those hours are also characterized by a high electricity price. To avoid under-representing possible capacity credits we repeated the dispatch optimization calculations for two cases: (1) CSP plant dispatched against the base case electricity prices, and (2) CSP plant dispatched against the base case electricity prices with an added "incentive" for dispatch in high net load hours. In the latter case we utilize a modified set of electricity prices in which the total possible capacity value is fractionally allocated to each of a subset of hours with the highest net load and added to the electricity price at that point in time. The result is a modified pricing profile in which high net load hours are characterized by an inflated electricity "price". Thus, we provide a strong incentive for the CSP plant to dispatch during hours with high net load, but rigorously enforce all constraints on plant operation and available energy which may prohibit it from doing so. Note that the revenue from electricity sales is computed with the base unmodified price profile in each case. Adding an incentive for dispatch in high net load hours can reduce the revenue from electricity sales because the plant may need to sacrifice generation in high-priced hours to prioritize dispatching in high-net load hours. Given the small number of hours (100) contributing the capacity value and the relatively high cost of new capacity (≥$150/kW-yr) considered in this analysis, we assume that the additional revenue earned by dispatching during hours contributing to capacity value always outweighs any potential reduction in revenue from electricity sales. The discrepancy in revenue from electricity sales from cases (1) and (2) above was less than $1.2/MWh for all configurations considered here.

Figure 23 illustrates the average CSP plant capacity factor during the 100 hours with the highest price (left column), or 100 hours with the highest net load (right column) as a function of solar multiple and thermal storage size. The plant is dispatched against either base case prices (top row), or prices modified in the 100 hours with the highest net load as described above (bottom row). Average capacity factors during high net load hours for CSP plant configurations with a solar multiple above unity exceed 0.9 and are similar to those reported by Jorgenson et al. [1]. The average capacity factor decreases with solar multiple but remains above 0.65 with a solar multiple as low as 0.5. For this particular data set, the highest net load hours occur in blocks over a relatively small number of summer days. 58 of the highest 100 net load hours occur within an 8-day period in mid-July, and 11 of the highest 100 net load hours occur within a block between noon and 11pm on a single day. For the smallest solar multiple configurations, the majority of the missed high load hours occur on days with good solar resource but insufficient thermal energy to generate near full capacity during the entire block of high load hours.

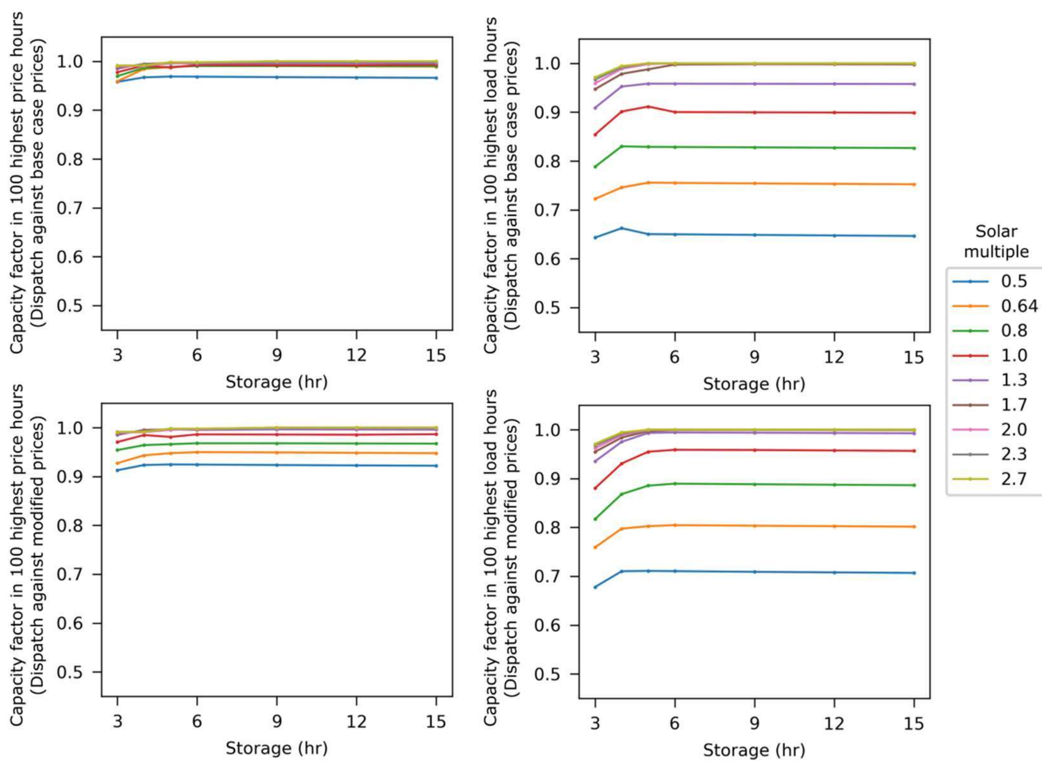


Figure 23 Average capacity factor in 100 hours with highest electricity price (left column), or highest net load (right column). CSP plant dispatch is optimized using either base case electricity prices (top row) or modified prices which provide an incentive for dispatch in the highest 100 net load hours (bottom row).

Figure 24 illustrates net revenue from electricity sales, capacity value, and total revenue for a range of CSP plant configurations. The capacity value is computed using the average capacity factor in the lower right corner of Figure 22. For a CSP plant with a solar multiple of 1.3 and 6 hours of storage, the net revenue from electricity sales and the range of capacity values ($45.0/MWh and $49.7/MWh - $63.0/MWh) agree well with those reported by Jorgenson et al. [1] for operational value and capacity value, respectively ($46.2/MWh and $49.8/MWh - $63.1/MWh). In each case ranges of capacity value correspond to annualized capacity cost between $150/kW-yr and $190/kW-yr. The capacity value is a significant fraction of total revenue, particularly for cases with a low solar multiple which utilize the largest turbine.

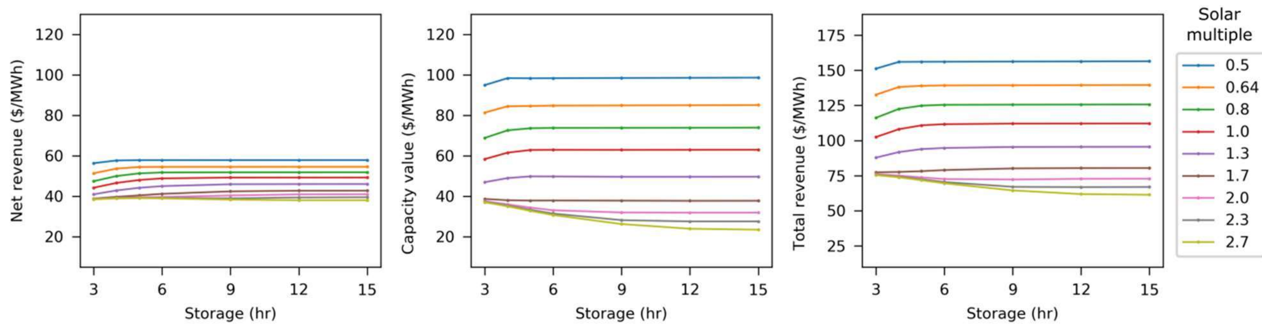
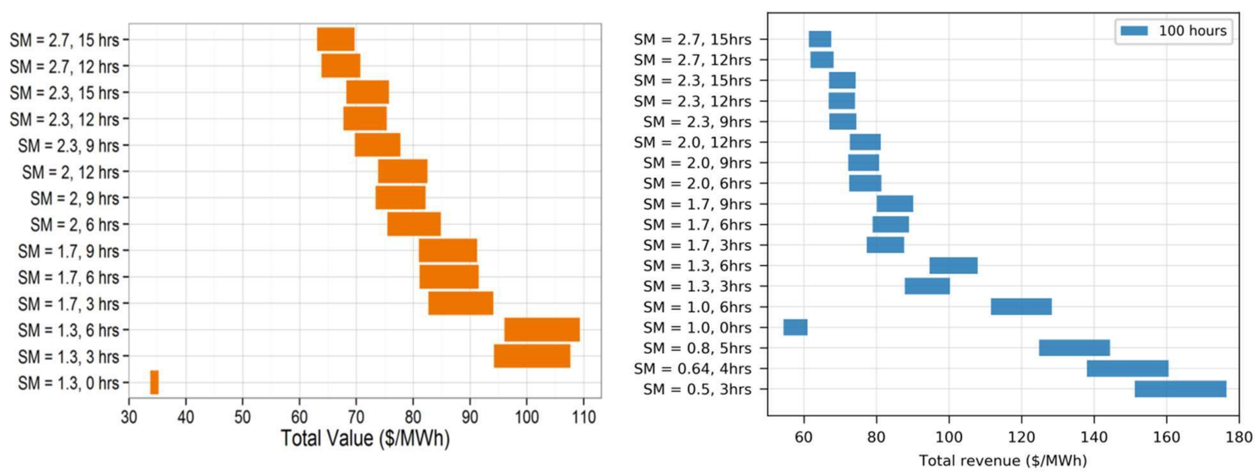


Figure 24 Net revenue from electricity sales, capacity value, and total revenue as a function of solar multiple and thermal storage size. Capacity value assumes an annualized cost of new capacity of $150/kW-yr

Figure 25 displays the results from Jorgenson et al. [1] alongside the results for corresponding configurations and new DSP configurations using the price-taker approach described here. Lower and upper bounds correspond to an annualized cost of new capacity equal to $150/kW-yr or $190/kW-yr. Note that this analysis includes only value or revenue and does not consider capital costs and other up-front costs for the various plant configurations. The trends in total revenue from the price-taker approach agree well with the original results from the production cost model. Total revenue continues to increase strongly with a decrease in solar multiple, despite the corresponding reduction in average capacity factor illustrated in Figure 23.



(a) (b)

Figure 25 Total revenue for selected configurations from (a) Jorgenson et al. [1], and (b) price-taker analysis. Ranges represent the difference between $150/kW-yr and $190/kW-yr annualized capacity cost.

As noted above, the case considered in this analysis contains high net load hours which tend to occur in blocks, with 11 of the highest 100 net load hours occurring during a single day. As such, a CSP plant configuration with a small solar multiple and storage capacity will be unable to dispatch during the entire block of high net-load hours, regardless of solar resource availability. Capacity factors were recomputed under additional scenarios designed to assess sensitivity of capacity value to underlying assumptions which are defined by the utility and may vary in a future scenario with high reliance on renewables. The analysis detailed in Figures 22-25 represents scenario 1, in which no limits are placed on the number of net load hours per day which contribute to capacity credit. In scenarios 2 and 3 we still define capacity credit based on CSP plant dispatch during a fixed total number of hours (100) with high net load but require the selected set of 100 net load hours to satisfy constraints on the maximum number of hours per day which can be included. The maximum number of hours per day was either set to six (scenario 2) or set to the thermal energy storage (TES) capacity (scenario 3).

Figure 26 illustrates average capacity factors based on 100 hours with high net load for each scenario. Constraining the number of hours per day increases the capacity factor for all cases; however, the capacity factor for the smallest solar multiple configurations (0.5-0.64) in scenario 2 (middle of Figure 26) remains below 0.9 because the available thermal energy is insufficient to operate the power cycle at full capacity for six straight hours. When the maximum number of hours per day is further constrained based on TES size (right side of Figure 26), the capacity factor for each discrete case illustrated in Figure 25 exceeds 0.95.

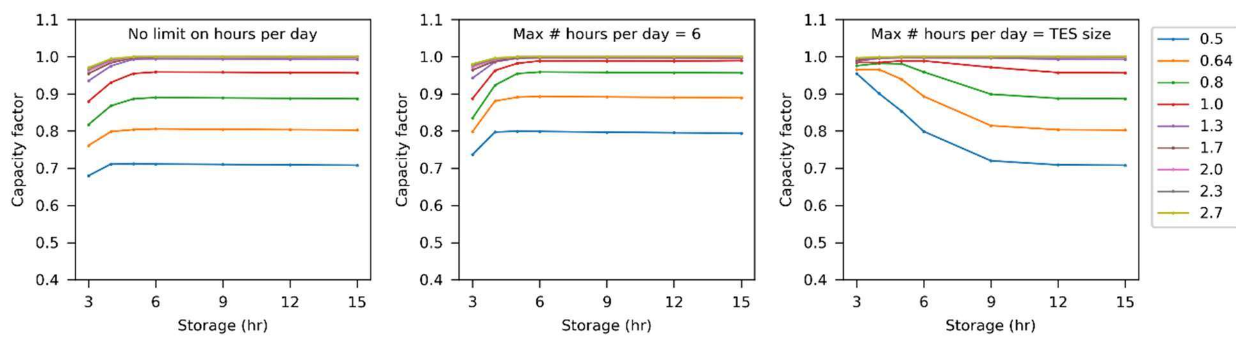


Figure 26 Average capacity factor during 100 hours with high net load with constraints imposed on the maximum number of hours selected in any given day

Figure 27 incorporates the capacity factors shown in Figure 26 into the calculation of total revenue. Only small differences exist in the revenue from electricity sales between the three scenarios for any given plant configuration. Correspondingly the variation between scenarios evident in Figure 27 is predominantly due to differences in capacity value which originate from the assumptions underlying the evaluation of capacity factors in Figure 26. These assumptions have minimal impact on the capacity value of large baseload plants but become an important consideration for assessing the capacity value of small solar multiple configurations.

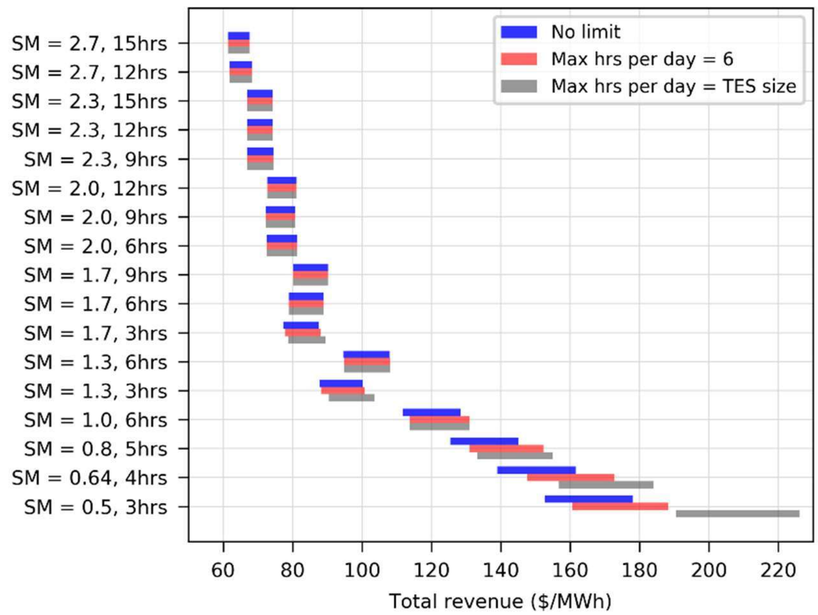


Figure 27 Total revenue for selected configurations including constraints on the maximum hours per day which contribute to capacity value. Width of each bar represents the difference between $150/kW-yr and $190/kW-yr annualized capacity cost.

<u>**References**</u>

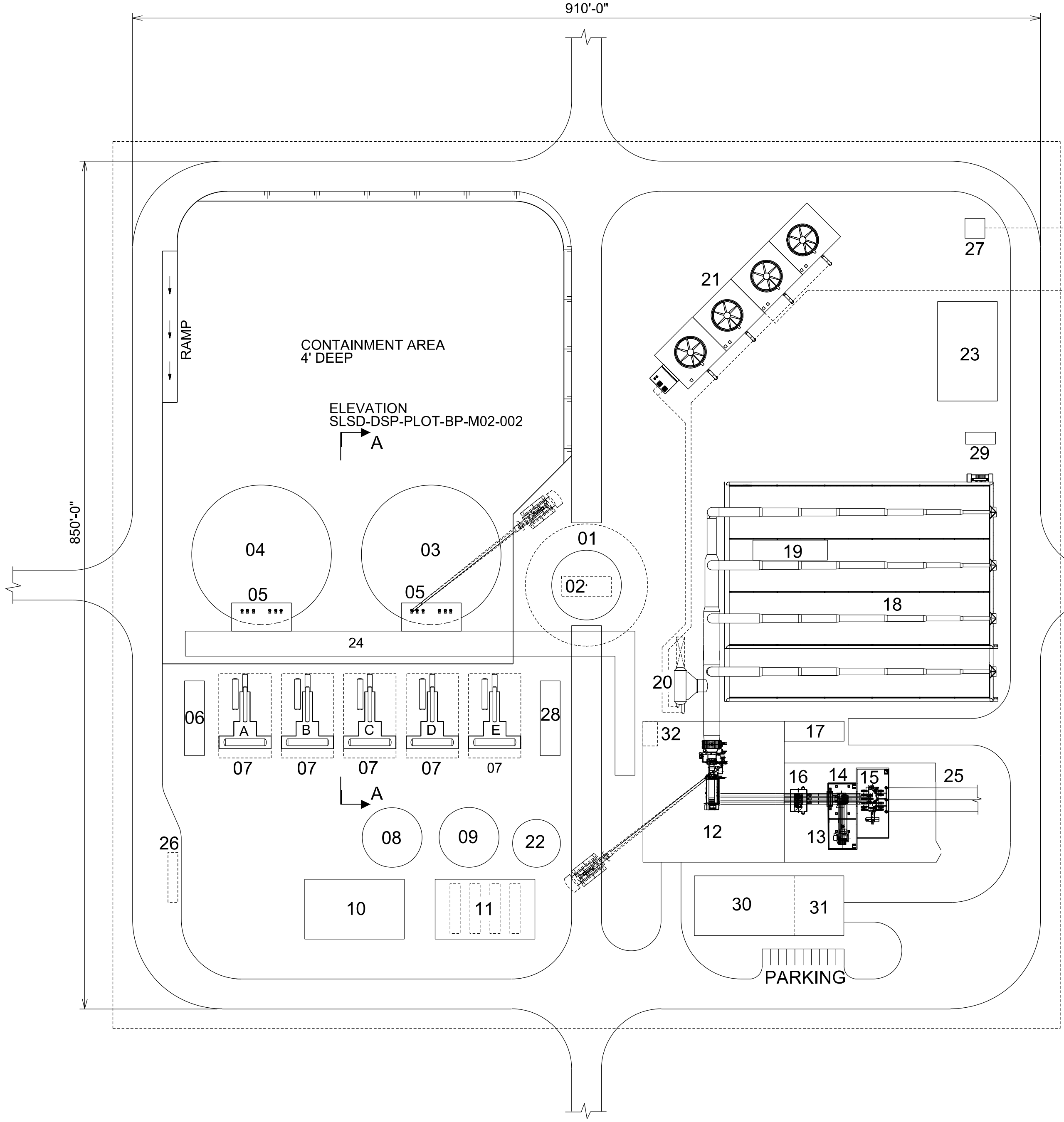
[1] Jorgenson, J.; Denholm, P.; Mehos, M. "Estimating the Value of Utility Scale Solar Technologies in California Under a 40% Renewable Portfolio Standard". NREL/TP-6A20-61685, 2014.

[2] Wagner, M.J.; Newman, A.M.; Hamilton, W. T.; Braun, R.J. "Optimized dispatch in a first-principles concentrating solar power production model." *Applied Energy* **203**, 959-971, 2017.

[3] Jorgenson, J.; Denholm, P.; Mehos, M.; Turchi, C. "Economic Value of Multiple Concentrating Solar Power Technologies in A Production Cost Model", NREL/TP-6A20-58645, 2013.

[4] Madaeni, S.H.; Sioshansi, R.; Denholm, P. "Estimating the Capacity Value of Concentrating Solar Power Plants: A Case Study of the Southwestern United States", *IEEE Transactions on Power Systems*, **27**(2), 1116-1124, 2012.

Appendix B – Sargent & Lundy DSP Plant Design Drawings



PLAN
POWER BLOCK AREA

LEGEND	
01	SOLAR RECEIVER
02	ELECTRICAL ROOM
03	HOT SALT TANK (140' DIA.)
04	COLD SALT TANK (140' DIA.)
05	MS PUMPS
06	GAS FIRED AUX. BOILER
07	SGS (5 UNITS)
08	RAW WATER TANK
09	DEMIN. WATER TANK
10	WATER TREATMENT FIRE PUMP BDG.
11	DEMIN. TRAILER AREA
12	STEAM TURBINE BLDG.
13	UNIT AUX. TRANSFORMER
14	UNIT AUX. TRANSFORMER
15	GSU TRANSFORMER
16	GENERATOR CIRCUIT BREAKER
17	MAIN / BFW / STG ELECTRICAL BUILDING
18	AIR COOLED CONDENSER
19	ACC/CT ELECTRICAL BUILDING
20	CONDENSER
21	COOLING TOWER
22	CONDENSATE TANK
23	WAREHOUSE CHEMICAL BUILDING
24	UTILITY RACK
25	230 KV TRANSMISSION CORRIDOR
26	WASH TRUCK FILL STATION
27	STORM WATER SEWER CATCH BASIN
28	SGS ELECTRICAL BUILDING
29	3 MW GAS FIRED STANDBY ELECTRIC GENERATOR
30	CONTROL ADMIN. BUILDING
31	MAINTENANCE BUILDING
32	COMPRESSED AIR SYSTEM

RELEASE INFORMATION

REV.	DATE	DESCRIPTION
0	09-26-2017	ISSUED FOR COMMENT
1	10-11-2017	ISSUED FOR FINAL REPORT

CAD FILE NAME: SLSD-DSP-PLOT-BP-M02-001.DGN
PREPARED BY: BMM
REVIEWED BY: VHS
APPROVED BY:

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

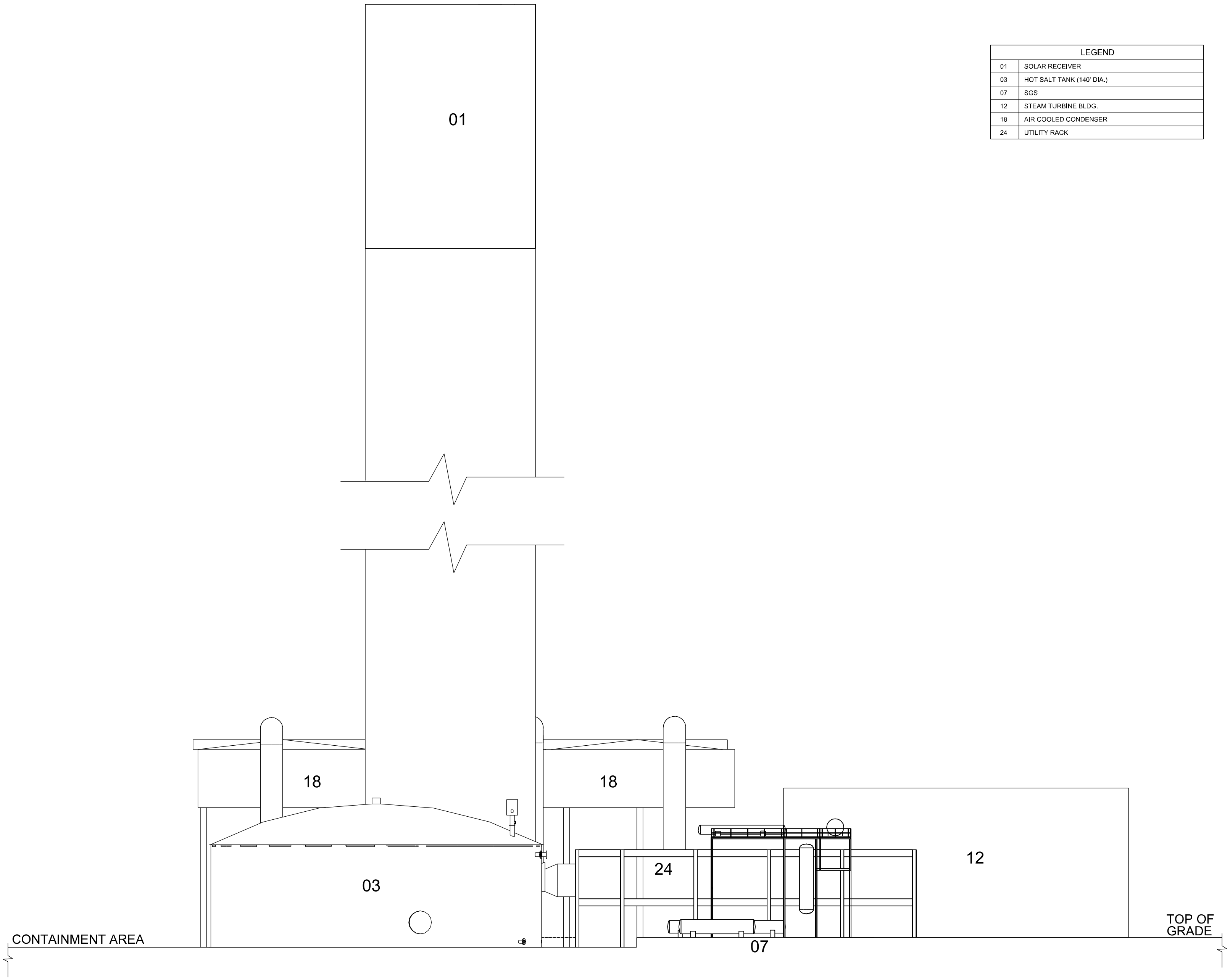
SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

Solar Dynamics

PROJECT
DSP PEAKER
CONCEPTUAL DESIGN

DRAWING TITLE
SITE LAYOUT
POWER BLOCK
PLAN

DRAWING NUMBER: SLSD-DSP-PLOT-BP-M02
REVISION: REV 1
SHEET 1 OF 2



SECTION A-A
POWER BLOCK AREA

LEGEND	
01	SOLAR RECEIVER
03	HOT SALT TANK (140' DIA.)
07	SGS
12	STEAM TURBINE BLDG.
18	AIR COOLED CONDENSER
24	UTILITY RACK

RELEASE INFORMATION

REV.	DATE	DESCRIPTION
0	09-26-2017	ISSUED FOR COMMENT
1	10-11-2017	ISSUED FOR FINAL REPORT

CAD FILE NAME: SALT SYSTEM_PFD_SOLAR DYNAMICS
PREPARED BY: BMM
REVIEWED BY: VHS
APPROVED BY:

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC
SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

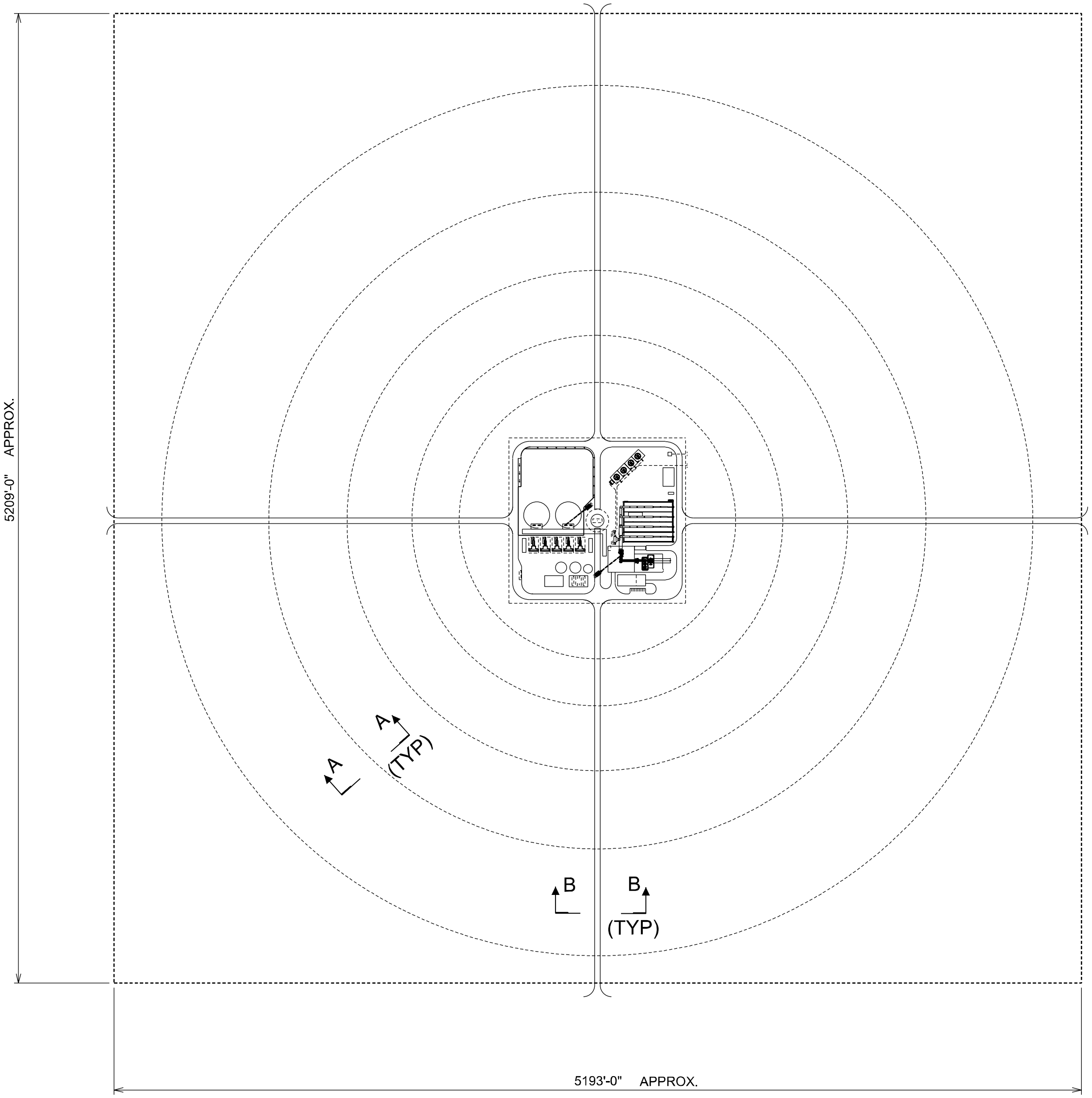
Solar Dynamics

PROJECT
DSP PEAKER
CONCEPTUAL DESIGN

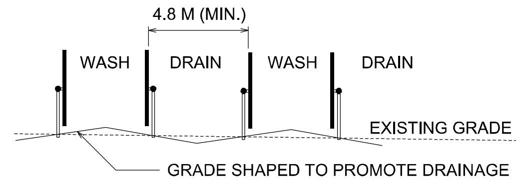
DRAWING TITLE
SITE LAYOUT
POWER BLOCK
ELEVATION

DRAWING NUMBER: SLSD-DSP-PLOT-BP-M02
REVISION: 1
SHEET 2 OF 2

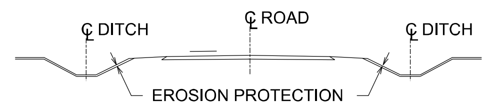
10/11/2017 4:09:37 PM
...\SLSD-DSP-PLOT-BP-M02-002.dgn
ZL10766\0976\D:\FPT\2-Plant Arrangement Process\8-Ref_General_Arrangements\7-Solar Tower\SLSD-DSP-PLOT-BP-M02-002.dgn
Form GDC-0401-01-08, ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 11A, Revision Date: 04-30-2010
SLSD-DSP-PLOT-BP-M02-002.dgn 10/11/2017 4:09:37 PM



PLAN
SOLAR FIELD



SECTION A-A



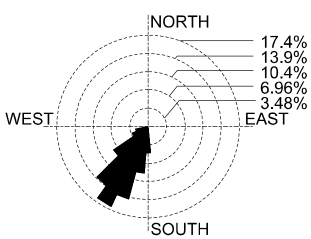
SECTION B-B

NOT TO SCALE

OFFSITE DETENTION POND (1.5 ACRES)

EVAPORATION POND (2 CELLS, TOTAL 20 ACRES)

CONSTRUCTION LAYDOWN AND OFFICE AREA (10 ACRES)



WIND ROSE PLOTS FOR JUNE, JULY, AUGUST AND SEPTEMBER FROM 3PM TO 9PM YEAR 2000 TO 2017

NOTES:

1. EPC CONTRACTOR IS ULTIMATELY RESPONSIBLE FOR DEVELOPING THE FINAL SITE DRAINAGE PLAN TAKING INTO CONSIDERATION THE EXISTING SITE CONDITIONS AS WELL AS ALL STATE, FEDERAL, AND LOCAL REGULATIONS INCLUDING THE MARICORP COUNTY DRAINAGE DESIGN MANUAL. THE SECTIONS SHOWN ARE CONCEPTUAL.
2. DRAINAGE DITCHES OUTSIDE THE POWERBLOCK AREA AND ALONG THE SOLARFIELD ROADS (PAVED AND GRADED) ARE TO BE CONNECTED TO THE EXISTING DRAINAGE SYSTEM (COUNTY) OUTSDE OF PROJECT SITE.
3. SOLAR FIELD SLOPES FROM NORTHEAST TO SOUTHWEST.

400' 0 1000'
GRAPHIC SCALE

NORTH

RELEASE INFORMATION		
REV.	DATE	DESCRIPTION
0	09-26-2017	ISSUED FOR COMMENT
1	10-11-2017	ISSUED FOR FINAL REPORT

CAD FILE NAME:	SALT SYSTEM_PFD_SOLAR DYNAMICS
PREPARED BY:	BMM
REVIEWED BY:	VHS
APPROVED BY:	

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

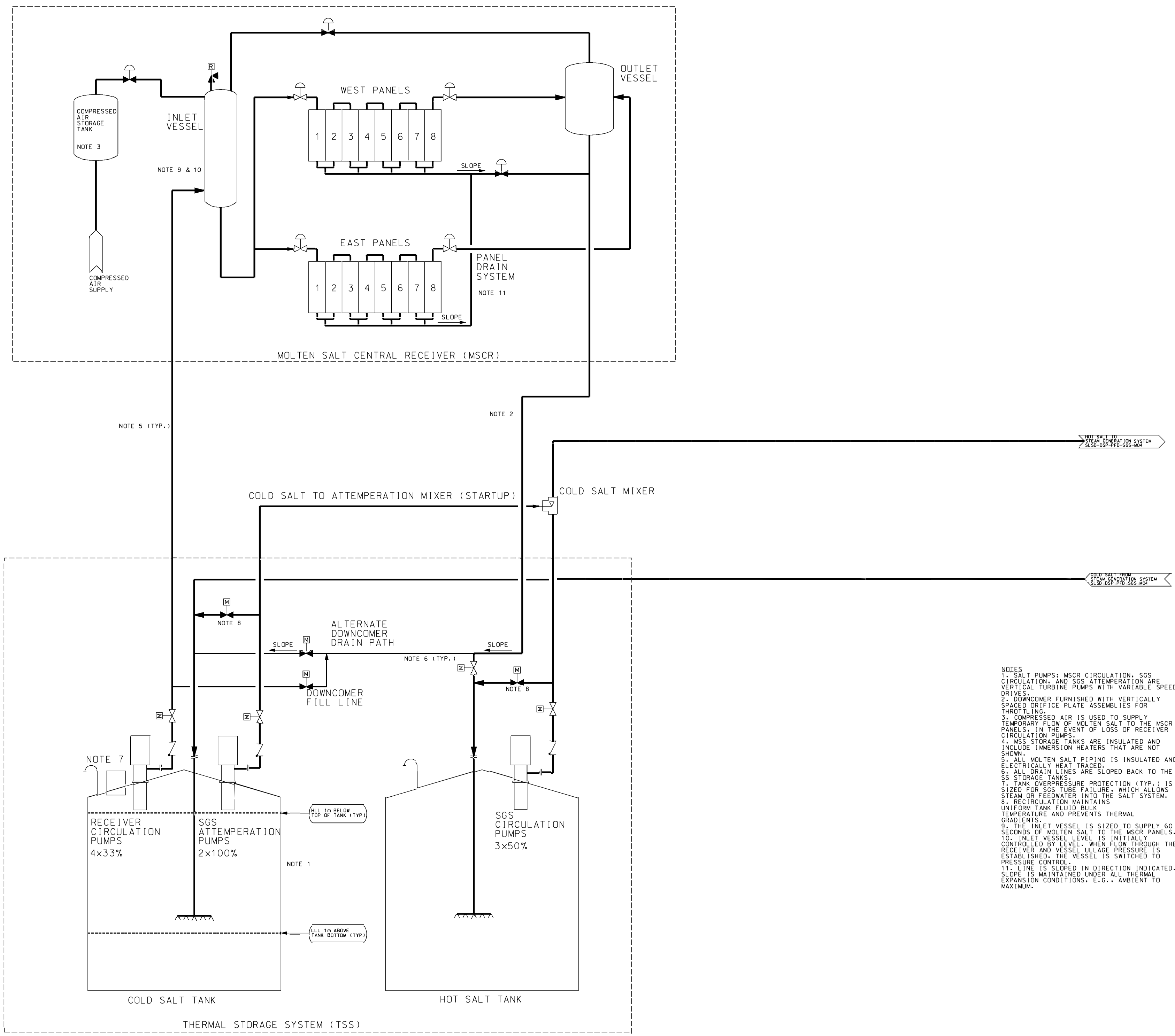
Sargent & Lundy LLC
SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

Solar Dynamics

PROJECT
DSP PEAKER
CONCEPTUAL DESIGN

DRAWING TITLE
SITE LAYOUT AND
CONCEPTUAL DRAINAGE PLAN
SOLAR FIELD

DRAWING NUMBER	REVISION
SLSD-DSP-PLOT-SF-M01	REV 1
SHEET 1 OF 1	



NOTES
1. SALT PUMPS: MSCR CIRCULATION, SGS CIRCULATION, AND SGS ATTEMPERATION ARE VERTICAL TURBINE PUMPS WITH VARIABLE SPEED DRIVES.
2. DOWNCOMER FURNISHED WITH VERTICALLY SPACED ORIFICE PLATE ASSEMBLIES FOR THROTTLING.
3. COMPRESSED AIR IS USED TO SUPPLY TEMPORARY FLOW OF MOLTEN SALT TO THE MSCR PANELS, IN THE EVENT OF LOSS OF RECEIVER CIRCULATION PUMPS.
4. MSS STORAGE TANKS ARE INSULATED AND INCLUDE IMMERSION HEATERS THAT ARE NOT SHOWN.
5. ALL MOLTEN SALT PIPING IS INSULATED AND ELECTRICALLY HEAT TRACED.
6. ALL DRAIN LINES ARE SLOPED BACK TO THE M SS STORAGE TANKS.
7. TANK OVERPRESSURE PROTECTION (TYP.) IS SIZED FOR SGS TUBE FAILURE, WHICH ALLOWS STEAM OR FEEDWATER INTO THE SALT SYSTEM.
8. RECIRCULATION MAINTAINS UNIFORM TANK FLUID BULK TEMPERATURE AND PREVENTS THERMAL GRADIENTS.
9. THE INLET VESSEL IS SIZED TO SUPPLY 60 SECONDS OF MOLTEN SALT TO THE MSCR PANELS.
10. INLET VESSEL LEVEL IS INITIALLY CONTROLLED BY LEVEL. WHEN FLOW THROUGH THE RECEIVER AND VESSEL ULLAGE PRESSURE IS ESTABLISHED, THE VESSEL IS SWITCHED TO PRESSURE CONTROL.
11. LINE IS SLOPED IN DIRECTION INDICATED. SLOPE IS MAINTAINED UNDER ALL THERMAL EXPANSION CONDITIONS, E.G., AMBIENT TO MAXIMUM.

RELEASE INFORMATION		
REV.	DATE	DESCRIPTION
0	07-10-2017	CLIENT REVIEW
1	10-04-2017	FINAL REPORT

CAD FILE NAME: SALT SYSTEM_PFD_SOLAR DYNAMICS
PREPARED BY: PSD
REVIEWED BY: JAH
APPROVED BY: RPC

Sargent & Lundy LLC
SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

Solar Dynamics

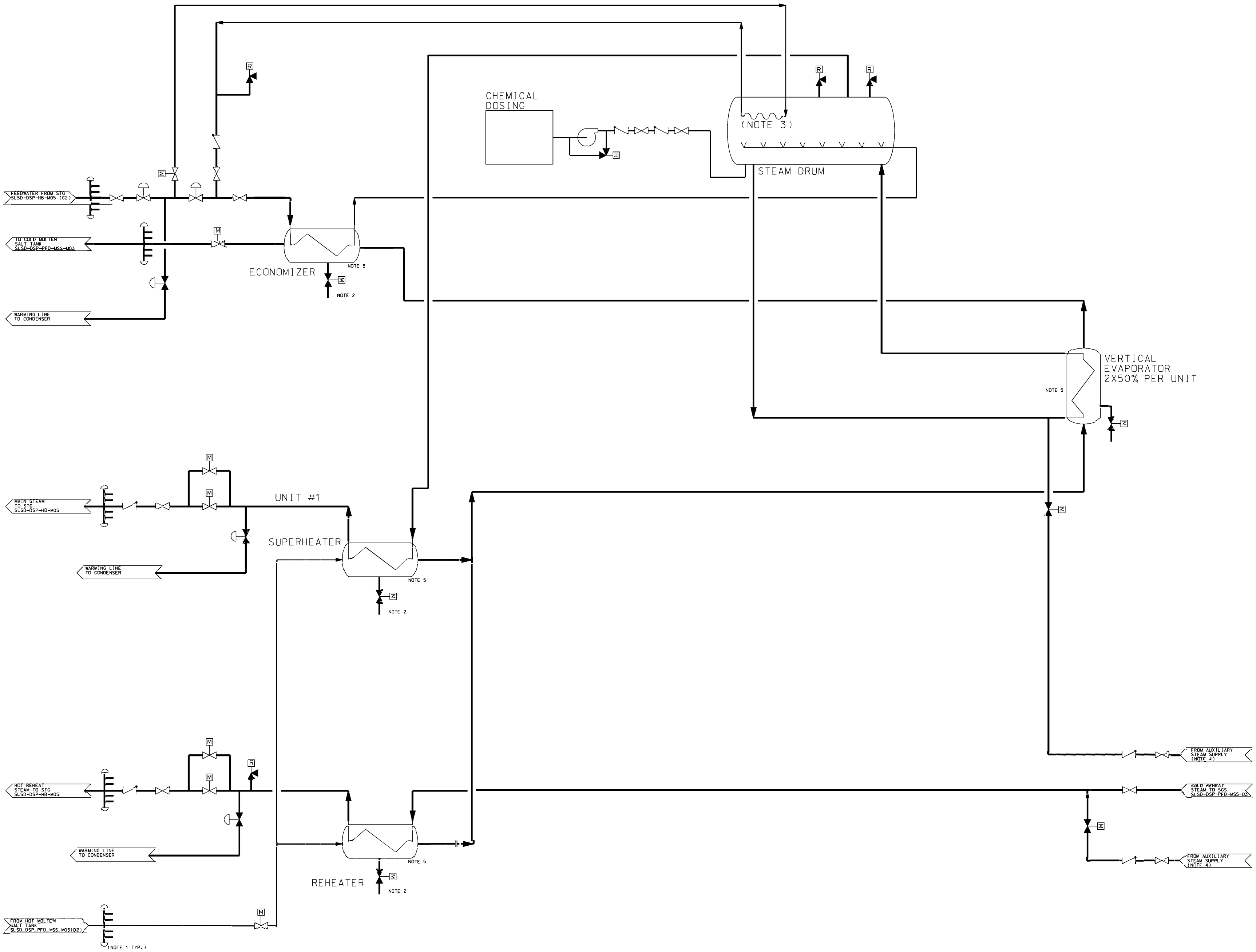
PROJECT
DSP PEAKER
CONCEPTUAL DESIGN

DRAWING TITLE
MOLTEN SALT SYSTEMS
PROCESS FLOW

DRAWING NUMBER	REVISION
SLSD-DSP-PFD-MSS-M03	1

SHEET 1 OF 1

10/10/2017 1:47:36 PM
..\Salt System_PFD_Solar Dynamics_04OCT17.dgn
ZL10762/O:9463/D:\NONE\codme\design\Salt System_PFD_Solar Dynamics_04OCT17.dgn
Form GDG-0401-01-08, ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 11A, Revision Date: 04-30-2010



NOTES

1. FIVE PARALLEL UNITS ARE REQUIRED TO GENERATE STEAM FOR 100% LOAD OF STG.
2. DRAIN BY GRAVITY TO MOLTEN SALT DRAIN TANK.
3. FEEDWATER PREHEATER MAINTAINS FEEDWATER TEMPERATURE ABOVE 500F.
4. AUXILIARY STEAM IS REQUIRED FOR START-UP AND HOLDING MODE.
5. MOLTEN SALT FLOWS THROUGH SHELL SIDE OF HEAT EXCHANGERS. STEAM OR WATER FLOWS TRHOUGH TUBES.

ONE UNIT SHOWN

RELEASE INFORMATION		
REV.	DATE	DESCRIPTION
0	07-10-2017	CLIENT REVIEW
1	10-04-2017	FINAL REPORT

CAD FILE NAME:
PREPARED BY: PSD
REVIEWED BY: JAH
APPROVED BY: RPC

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC
SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

Solar Dyanmics

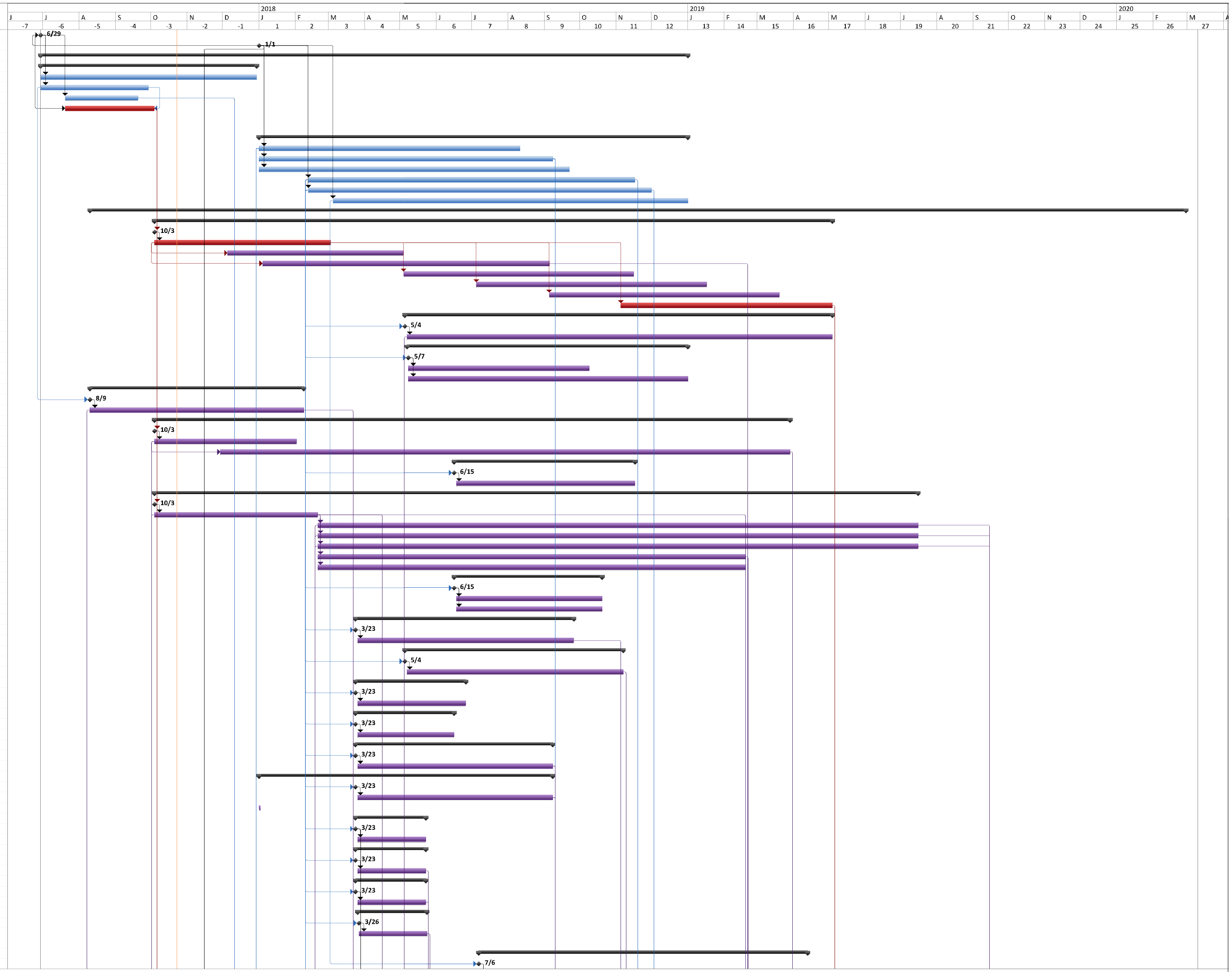
PROJECT
DSP PEAKER
CONCEPTIONAL DESIGN

DRAWING TITLE
STEAM GENERATION SYSTEM
PROCESS FLOW

DRAWING NUMBER: SLSD-DSP-PFD-SGS-M04
REVISION: 1
SHEET 1 OF 1

Appendix C – Sargent & Lundy DSP Plant Conceptual Level 2 EPC Schedule

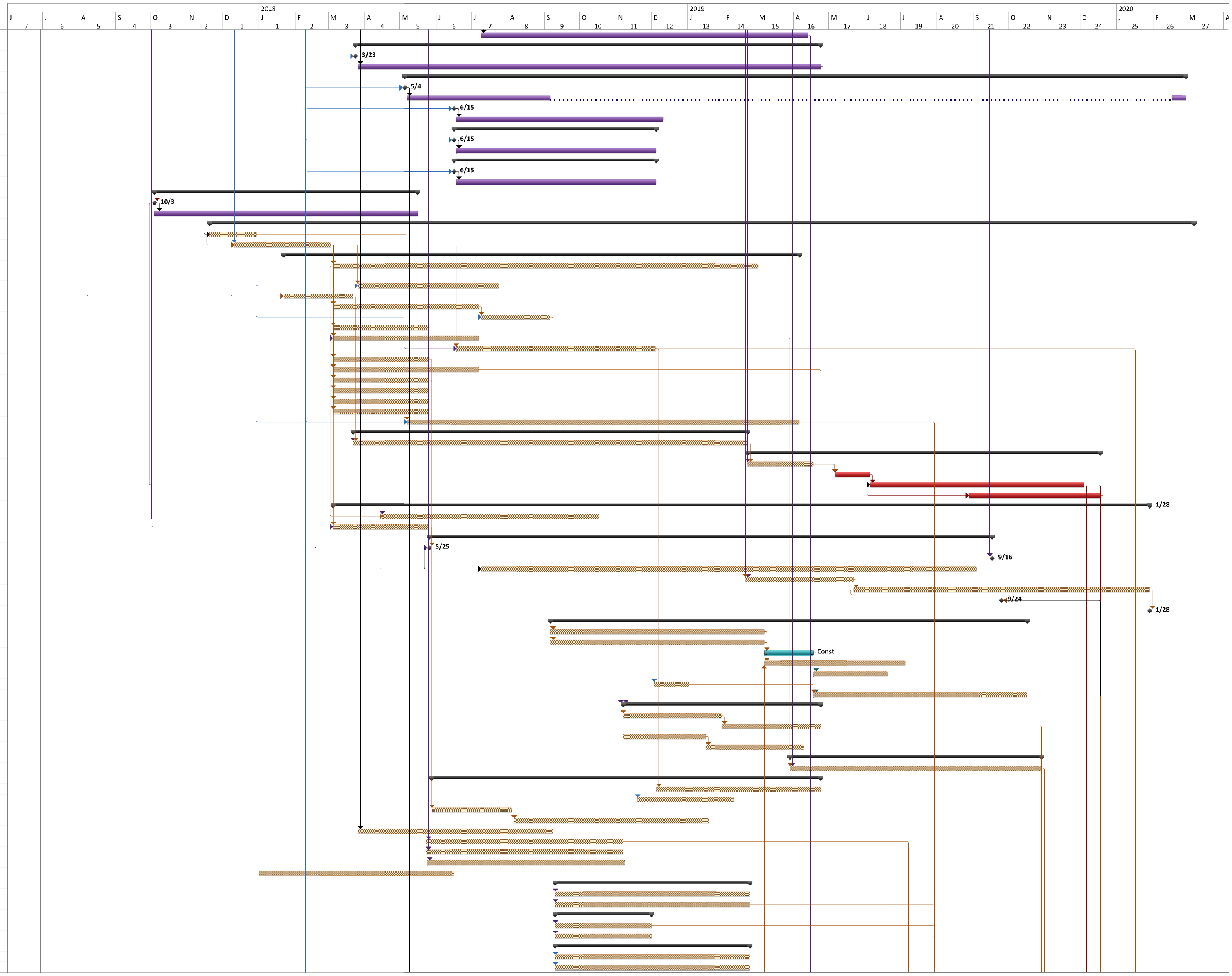
ID	Task Mode	Task Name	Duration	Text1	Start	Finish
1		**LNTP**	0 days	0.0 months	6/29/17	6/29/17
2		**FNTP**	0 days	0.0 months	1/1/18	1/1/18
3		**Engineering**	**393 days**	**18.1 months**	**6/29/17**	**12/31/18**
4		**Engineering - LNTP**	**132 days**	**6.1 months**	**6/29/17**	**12/29/17**
5		General Design	132 days	6.1 months	6/29/17	12/29/17
6		Engineering LTNP	66 days	3.0 months	6/29/17	9/28/17
7		Engineering Pre-construction Permits	44 days	2.0 months	7/20/17	9/19/17
8		Issue PO STG, Heliostat Field, Tower, Receiver and Large Bore Speciality Piping	54 days	2.5 months	7/20/17	10/3/17
9		**Engineering - FNTP**	**261 days**	**12.0 months**	**1/1/18**	**12/31/18**
10		Civil Engineering	160 days	7.4 months	1/1/18	8/10/18
11		Buildings	180 days	8.3 months	1/1/18	9/7/18
12		Structural	190 days	8.8 months	1/1/18	9/21/18
13		Mechanical	200 days	9.2 months	2/12/18	11/16/18
14		Electrical	210 days	9.7 months	2/12/18	11/30/18
15		I&C	216 days	10.0 months	3/5/18	12/31/18
16		**Procurement**	**667 days?**	**30.8 months**	**8/9/17**	**2/28/20**
17		**Receiver (Design & Mfg)**	**413 days**	**19.1 months**	**10/3/17**	**5/3/19**
18		Receiver PO	0 days	0.0 months	10/3/17	10/3/17
19		Design Panels	108 days	5.0 months	10/4/17	3/2/18
20		Piping	108 days	5.0 months	12/5/17	5/3/18
21		Structure, Mfg & delivery	174 days	8.0 months	1/4/18	9/4/18
22		4 panels, Mfg & Delivery	140 days	6.5 months	5/4/18	11/15/18
23		4 panels, Mfg & Delivery	140 days	6.5 months	7/5/18	1/16/19
24		4 panels, Mfg & Delivery	140 days	6.5 months	9/5/18	3/19/19
25		4 panels, Mfg & Delivery	130 days	6.0 months	11/5/18	5/3/19
26		**Air Cooled Condensor**	**260 days**	**12.0 months**	**5/4/18**	**5/3/19**
27		ACC PO	0 days	0.0 months	5/4/18	5/4/18
28		ACC Mfg	260 days	12.0 months	5/7/18	5/3/19
29		**Hybrid Cooling**	**171 days**	**7.9 months**	**5/7/18**	**12/31/18**
30		Hybrid Cooling PO	1 day	0.0 months	5/7/18	5/7/18
31		MDCT Components, Mfg & Delivery	110 days	5.1 months	5/8/18	10/8/18
32		Surface Condenser, Mfg & Delivery	170 days	7.8 months	5/8/18	12/31/18
33		**Receiver Tower**	**130 days**	**6.0 months**	**8/9/17**	**2/7/18**
34		Tower PO	0 days	0.0 months	8/9/17	8/9/17
35		Tower Design	130 days	6.0 months	8/10/17	2/7/18
36		**Steam Turbine Generator**	**387 days**	**17.9 months**	**10/3/17**	**3/28/19**
37		Steam Turbine PO	0 days	0.0 months	10/3/17	10/3/17
38		STG Design	87 days	4.0 months	10/4/17	2/1/18
39		STG Mfg	347 days	16.0 months	11/29/17	3/28/19
40		**Steam Generation**	**110 days**	**5.1 months**	**6/15/18**	**11/16/18**
41		Steam Generation PO	0 days	0.0 months	6/15/18	6/15/18
42		SG Mfg	110 days	5.1 months	6/18/18	11/16/18
43		**Solar Field**	**464 days**	**21.4 months**	**10/3/17**	**7/15/19**
44		Heliostat Field PO	0 days	0.0 months	10/3/17	10/3/17
45		Heliostat Field Design	99 days	4.6 months	10/4/17	2/19/18
46		Mirror Mfg	365 days	16.8 months	2/20/18	7/15/19
47		Structure Mfg	365 days	16.8 months	2/20/18	7/15/19
48		Drive Mfg	365 days	16.8 months	2/20/18	7/15/19
49		Controls Mfg	260 days	12.0 months	2/20/18	2/18/19
50		Master Control System	260 days	12.0 months	2/20/18	2/18/19
51		**Molten Salt Tanks**	**90 days**	**4.2 months**	**6/15/18**	**10/19/18**
52		Molten Salt Tank PO	0 days	0.0 months	6/15/18	6/15/18
53		Cold Salt Tank	90 days	4.2 months	6/18/18	10/19/18
54		Hot Salt Tank	90 days	4.2 months	6/18/18	10/19/18
55		**Molten Salt Pumps**	**132 days**	**6.1 months**	**3/23/18**	**9/25/18**
56		Molten Salt Pump PO	0 days	0.0 months	3/23/18	3/23/18
57		Molten Salt Pump Mfg	132 days	6.1 months	3/26/18	9/25/18
58		**Molten Salt Valves**	**132 days**	**6.1 months**	**5/4/18**	**11/6/18**
59		Molten Salt Valve PO	0 days	0.0 months	5/4/18	5/4/18
60		Molten Salt Valve Mfg	132 days	6.1 months	5/7/18	11/6/18
61		**Molten Salt**	**66 days**	**3.0 months**	**3/23/18**	**6/25/18**
62		**Molten Salt PO**	0 days	0.0 months	3/23/18	3/23/18
63		Molten Salt Delivery	66 days	3.0 months	3/26/18	6/25/18
64		**Molten Salt Melting**	**60 days**	**2.8 months**	**3/23/18**	**6/15/18**
65		Molten Salt Melting PO	0 days	0.0 months	3/23/18	3/23/18
66		Molten Salt Equipment Delivery	60 days	2.8 months	3/26/18	6/15/18
67		**Water Treatment**	**120 days**	**5.5 months**	**3/23/18**	**9/7/18**
68		Water Treatment PO	0 days	0.0 months	3/23/18	3/23/18
69		Water Treatment Equip Mfg	120 days	5.5 months	3/26/18	9/7/18
70		**Tanks**	**180 days?**	**8.3 months**	**1/1/18**	**9/7/18**
71		Tanks PO	0 days	0.0 months	3/23/18	3/23/18
72		Tank Material Mfgr	120 days	5.5 months	3/26/18	9/7/18
73		Fire Protection	1 day?	0.0 months	1/1/18	1/1/18
74		**Fire Protection**	**42 days**	**1.9 months**	**3/23/18**	**5/22/18**
75		Fire Protection PO	0 days	0.0 months	3/23/18	3/23/18
76		Fire Protection Equip Delivery	42 days	1.9 months	3/26/18	5/22/18
77		**Compressed Air System**	**42 days**	**1.9 months**	**3/23/18**	**5/22/18**
78		Compressed Air PO	0 days	0.0 months	3/23/18	3/23/18
79		Compressed Air Equip Delivery	42 days	1.9 months	3/26/18	5/22/18
80		**Feedwater/Condensate System**	**42 days**	**1.9 months**	**3/23/18**	**5/22/18**
81		Fdwr/Condensate PO	0 days	0.0 months	3/23/18	3/23/18
82		Fdwr/Condensate Mfgr & Equip Delivery	42 days	1.9 months	3/26/18	5/22/18
83		**Extraction Steam/Heater Drains**	**43 days?**	**2.0 months**	**3/26/18**	**5/23/18**
84		Extraction Steam/Heater Drains PO	1 day?	0.0 months	3/26/18	3/26/18
85		Extraction Stm/Htr Drains Equip Delivery	42 days	1.9 months	3/27/18	5/23/18
86		**DCS**	**200 days**	**9.2 months**	**7/6/18**	**4/12/19**
87		DCS PO	0 days	0.0 months	7/6/18	7/6/18



Project: Peaker Tower Project1_7
Date: 10/23/17
Preliminary Draft

Eng	Comm	Summary	External Milestone	Inactive Summary	Manual Summary Rollup	Finish-only	Critical Split
Proc	Split	Project Summary	Inactive Task	Manual Task	Manual Summary	Deadline	Progress
Const	Milestone	External Tasks	Inactive Milestone	Duration-only	Start-only	Critical	

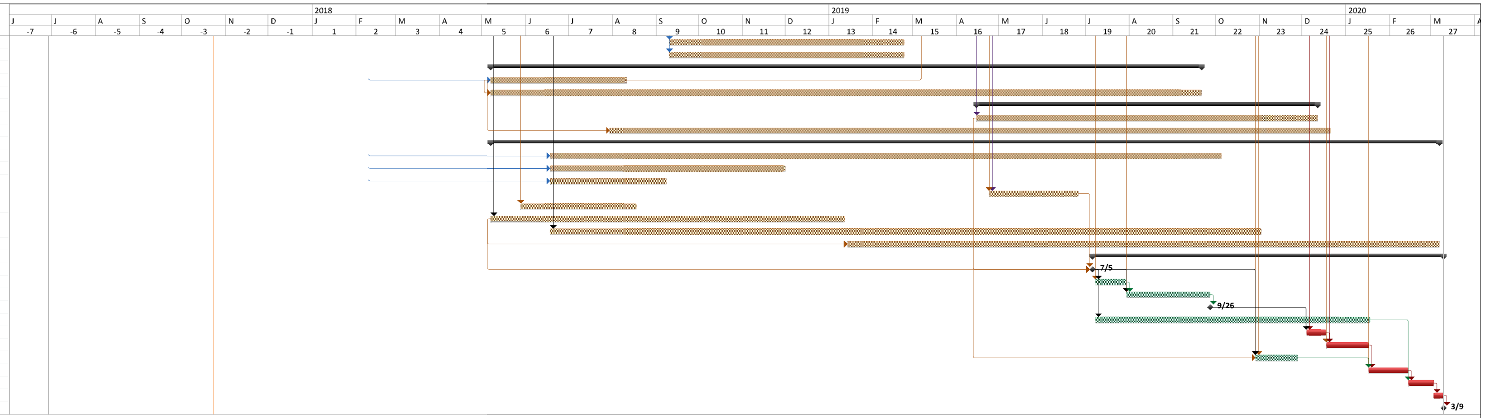
ID	Task Mode	Task Name	Duration	Text1	Start	Finish
88		DCS Mfg & Delivery	200 days	9.2 months	7/9/18	4/12/19
89		**Main Transformer**	**282 days**	**13.0 months**	**3/23/18**	**4/23/19**
90		**Main Transformer PO**	0 days	0.0 months	3/23/18	3/23/18
91		Main Transformers Mfg	282 days	13.0 months	3/26/18	4/23/19
92		**Electrical**	**475 days**	**21.9 months**	**5/4/18**	**2/28/20**
93		**Electrical Switchgear PO**	0 days	0.0 months	5/4/18	5/4/18
94		Electrial Swgr Mgr	98 days	4.5 months	5/7/18	2/28/20
95		**Electrical PO**	0 days	0.0 months	6/15/18	6/15/18
96		Electrical Mfg (Equip/Cable)	126 days	5.8 months	6/18/18	12/10/18
97		**Heat Tracing**	**122 days**	**5.6 months**	**6/15/18**	**12/4/18**
98		Heat Tracing PO	0 days	0.0 months	6/15/18	6/15/18
99		Heat Tracing Mfg	122 days	5.6 months	6/18/18	12/4/18
100		**Electrical Heater**	**122 days**	**5.6 months**	**6/15/18**	**12/4/18**
101		Electric Heaters (Molten Salt) PO	0 days	0.0 months	6/15/18	6/15/18
102		Electric Heaters (MS) Mfg	122 days	5.6 months	6/18/18	12/4/18
103		**Piping**	**160 days**	**7.4 months**	**10/3/17**	**5/15/18**
104		Large Bore Piping PO	0 days	0.0 months	10/3/17	10/3/17
105		Large Bore Fabrication	160 days	7.4 months	10/4/17	5/15/18
106		**Construction**	**600 days**	**27.7 months**	**11/20/17**	**3/6/20**
107		Site Mobilization	30 days	1.4 months	11/20/17	12/29/17
108		Site Preparation	60 days	2.8 months	12/11/17	3/2/18
109		**Civil Works**	**315 days**	**14.5 months**	**1/22/18**	**4/5/19**
110		Solar Field Earthworks (Survey, Roads, Fence)	260 days	12.0 months	3/5/18	3/1/19
111		Irrigation Channel Removed/Rerouted	86 days	4.0 months	3/26/18	7/23/18
112		Tower Foundation	43 days	2.0 months	1/22/18	3/21/18
113		Molten Salt Containment Area	90 days	4.2 months	3/5/18	7/6/18
114		Molten Salt Tank Foundation	43 days	2.0 months	7/9/18	9/5/18
115		SGS Foundation	60 days	2.8 months	3/5/18	5/25/18
116		STG Foundation	90 days	4.2 months	3/5/18	7/6/18
117		ACC Foundation	122 days	5.6 months	6/18/18	12/4/18
118		Mech Cooling Tower Foundation	60 days	2.8 months	3/5/18	5/25/18
119		Main Trans Foundations	90 days	4.2 months	3/5/18	7/6/18
120		Electrical Control Building Foundation	60 days	2.8 months	3/5/18	5/25/18
121		Electrical Building	60 days	2.8 months	3/5/18	5/25/18
122		Water Treatment Area Foundations	60 days	2.8 months	3/5/18	5/25/18
123		Evaporation Ponds	60 days	2.8 months	3/5/18	5/25/18
124		Wells	240 days	11.1 months	5/7/18	4/5/19
125		**Receiver Tower**	**240 days**	**11.1 months**	**3/22/18**	**2/20/19**
126		Tower Erection	240 days	11.1 months	3/22/18	2/20/19
127		**Receiver**	**214 days**	**9.9 months**	**2/21/19**	**12/17/19**
128		Receiver Structure Installation	40 days	1.8 months	2/21/19	4/17/19
129		Receiver Panel Installation	22 days	1.0 months	5/6/19	6/4/19
130		Receiver & Tower Piping	130 days	6.0 months	6/5/19	12/3/19
131		Piping Insulation	80 days	3.7 months	8/28/19	12/17/19
132		**Heliostat Field**	**497 days**	**22.9 months**	**3/5/18**	**1/28/20**
133		Heliostat Foundations	132 days	6.1 months	4/16/18	10/16/18
134		Heliostat Assembly Bldg	60 days	2.8 months	3/5/18	5/25/18
135		**Heliostat Assembly**	**341 days**	**15.7 months**	**5/25/18**	**9/16/19**
136		Heliostat Assembly Start	0 days	0.0 months	5/25/18	5/25/18
137		Heliostat Assembly Finish	0 days	0.0 months	9/16/19	9/16/19
138		Set Heliostats on Pedestal	302 days	13.9 months	7/9/18	9/3/19
139		Heliostat Control System	66 days	3.0 months	2/19/19	5/21/19
140		Characterization	180 days	8.3 months	5/22/19	1/28/20
141		75% of Solar Field Complete	0 days	0.0 months	9/24/19	9/24/19
142		100% of Solar Field Complete	0 days	0.0 months	1/28/20	1/28/20
143		**Molten Salt Tanks**	**290 days**	**13.4 months**	**9/6/18**	**10/16/19**
144		Molten Salt Cold Tank Erection	130 days	6.0 months	9/6/18	3/6/19
145		Molten Salt Hot Tank Erection	130 days	6.0 months	9/6/18	3/6/19
146		Molten Salt Tanks Water Hydro	30 days	1.4 months	3/7/19	4/17/19
147		Molten Salt Tank Pumps and Piping	86 days	4.0 months	3/7/19	7/4/19
148		Molten Salt Tank Insulation	45 days	2.1 months	4/18/19	6/19/19
149		Salt System Electrical Heater	22 days	1.0 months	12/3/18	1/1/19
150		Melting Salt and Fill	130 days	6.0 months	4/18/19	10/16/19
151		**Steam Generation System**	**120 days**	**5.5 months**	**11/7/18**	**4/23/19**
152		SGS Structure	60 days	2.8 months	11/7/18	1/29/19
153		SGS Equipment Erection	60 days	2.8 months	1/30/19	4/23/19
154		Heat Tracing	50 days	2.3 months	11/7/18	1/15/19
155		SGS Insulation	60 days	2.8 months	1/16/19	4/9/19
156		**Steam Turbine Generator**	**152 days**	**7.0 months**	**3/29/19**	**10/28/19**
157		STG Erection	152 days	7.0 months	3/29/19	10/28/19
158		**ACC**	**237 days**	**10.9 months**	**5/28/18**	**4/23/19**
159		ACC Erection	100 days	4.6 months	12/5/18	4/23/19
160		Main Surface Condenser Erection	60 days	2.8 months	11/19/18	2/8/19
161		Mech Cooling Twr Erection	50 days	2.3 months	5/28/18	8/3/18
162		Closed Cooling Wtr Erection	120 days	5.5 months	8/6/18	1/18/19
163		**Fire Protection System**	120 days	5.5 months	3/26/18	9/7/18
164		**Compressed Air System**	120 days	5.5 months	5/23/18	11/6/18
165		**Feedwater/Condensate System**	120 days	5.5 months	5/23/18	11/6/18
166		**Extraction Steam/Heater Drains**	120 days	5.5 months	5/24/18	11/7/18
167		**High Pressure Steam Piping**	120 days	5.5 months	1/1/18	6/15/18
168		**Water Treatment**	**120 days**	**5.5 months**	**9/10/18**	**2/22/19**
169		Pretreatment	120 days	5.5 months	9/10/18	2/22/19
170		RO	120 days	5.5 months	9/10/18	2/22/19
171		**Tanks**	**60 days**	**2.8 months**	**9/10/18**	**11/30/18**
172		Demin Water Storage Tank	60 days	2.8 months	9/10/18	11/30/18
173		Raw Water Tank	60 days	2.8 months	9/10/18	11/30/18
174		**Buildings**	**120 days**	**5.5 months**	**9/10/18**	**2/22/19**
175		Admin Building	120 days	5.5 months	9/10/18	2/22/19
176		Electrical Control Building	120 days	5.5 months	9/10/18	2/22/19



Project: Peaker Tower Project1_7
Date: 10/23/17
Preliminary Draft

Eng		Comm		Summary		External Milestone		Inactive Summary		Manual Summary Rollup		Finish-only		Critical Split	
Proc		Split		Project Summary		Inactive Task		Manual Task		Manual Summary		Deadline		Progress	
Const		Milestone		External Tasks		Inactive Milestone		Duration-only		Start-only		Critical			

ID	Task Mode	Task Name	Duration	Text1	Start	Finish
177		Warehouse and Maintenance Facility	120 days	5.5 months	9/10/18	2/22/19
178		Water Treatment Building	120 days	5.5 months	9/10/18	2/22/19
179		**Piping**	**360 days**	**16.6 months**	**5/7/18**	**9/20/19**
180		Pipe Bridge	70 days	3.2 months	5/7/18	8/10/18
181		Piping	360 days	16.6 months	5/7/18	9/20/19
182		**DCS**	**173 days**	**8.0 months**	**4/15/19**	**12/11/19**
183		DCS Install	173 days	8.0 months	4/15/19	12/11/19
184		**Instr**	365 days	16.8 months	7/30/18	12/20/19
185		**Electrical**	**480 days**	**22.2 months**	**5/7/18**	**3/6/20**
186		230kV Switchyard	340 days	15.7 months	6/18/18	10/4/19
187		Transmission Line	120 days	5.5 months	6/18/18	11/30/18
188		Interconnection at Substation	60 days	2.8 months	6/18/18	9/7/18
189		Main Trans Erection	45 days	2.1 months	4/24/19	6/25/19
190		Diesel Generator	60 days	2.8 months	5/28/18	8/17/18
191		Electrical Distribution	180 days	8.3 months	5/7/18	1/11/19
192		Electrical Tray Installation	360 days	16.6 months	6/18/18	11/1/19
193		Cable Installation	300 days	13.8 months	1/14/19	3/6/20
194		**Commissioning**	**176 days**	**8.1 months**	**7/5/19**	**3/9/20**
195		Backfeed Power	0 days	0.0 months	7/5/19	7/5/19
196		Commission Instrument Air System	16 days	0.7 months	7/8/19	7/29/19
197		Commission Water Treatment System	43 days	2.0 months	7/30/19	9/26/19
198		Water Available	0 days	0.0 months	9/26/19	9/26/19
199		Commission Systems	140 days	6.5 months	7/8/19	1/17/20
200		MSS Water Flow Test	10 days	0.5 months	12/4/19	12/17/19
201		Solar Field & Receiver Integrated Test	22 days	1.0 months	12/18/19	1/16/20
202		Steam Turbine Steam/Air Blow	22 days	1.0 months	10/29/19	11/27/19
203		Steam Turbine Commissioning	20 days	0.9 months	1/17/20	2/13/20
204		Integrated Plant Operation	12 days	0.6 months	2/14/20	3/2/20
205		Performance Test	5 days	0.2 months	3/3/20	3/9/20
206		Commercial Operation	0 days	0.0 months	3/9/20	3/9/20



Project: Peaker Tower Project1_7
Date: 10/23/17
Preliminary Draft

Eng | Comm | Summary | External Milestone | Inactive Summary | Manual Summary Rollup | Finish-only | Critical Split
Proc | Split | Project Summary | Inactive Task | Manual Task | Manual Summary | Deadline | Progress
Const | Milestone | External Tasks | Inactive Milestone | Duration-only | Start-only | Critical

Appendix D – Tower Visual Impact Mitigation

Prepared by: Keith Gawlik and Tim Wendelin

Tower Brightness and Cooling Studies

Solar Dynamics evaluated both the visual impact of receiver and spill zone brightness and methods to cool the spill zones when low reflectance coatings are used. The first study was done in collaboration with NREL, whose expertise in performing ray tracing modeling was necessary to determine detailed flux maps on the receiver and spill zones. The second study was done using the NREL flux maps and resulted in a novel method to cool spill zones.

Visual Impact of Tower Brightness

NREL studied incident and reflected flux levels on the receiver and upper and lower spill zones in two phases. The first phase investigated total incident and reflected flux on the three areas for a range of values for four parameters related to heliostat and spill zone characteristics, and two parameters related to time of year and day. The study parameters are summarized below.

Heliostat area	150, 76.5, 27.5, 21 m^2
Slope error	4, 3, 2, 1.27 mrad
Heliostat reflectivity	0.95, 0.92, 0.90
Spill reflectivity	1, 0.9, 0.8
Dates	Solstices, equinox
Times	Noon, 9 a.m.

The study evaluated the potential for after-images from the different areas of the tower according to the methodology described in Ho[15]. The method predicts the potential for after-images and retinal burn as a function of the subtended angle in viewing the bright object and the irradiance on the viewer's retina. The different hazard zones are summarized in Figure 28.

[15] Ho, C., Ghanbari, C., Diver, R., "Methodology to Assess Potential Glint and Glare Hazards From Concentrating Solar Power Plant: Analytical Models and Experimental Validation," Journal of Solar Energy Engineering, August 2011, vol. 133.

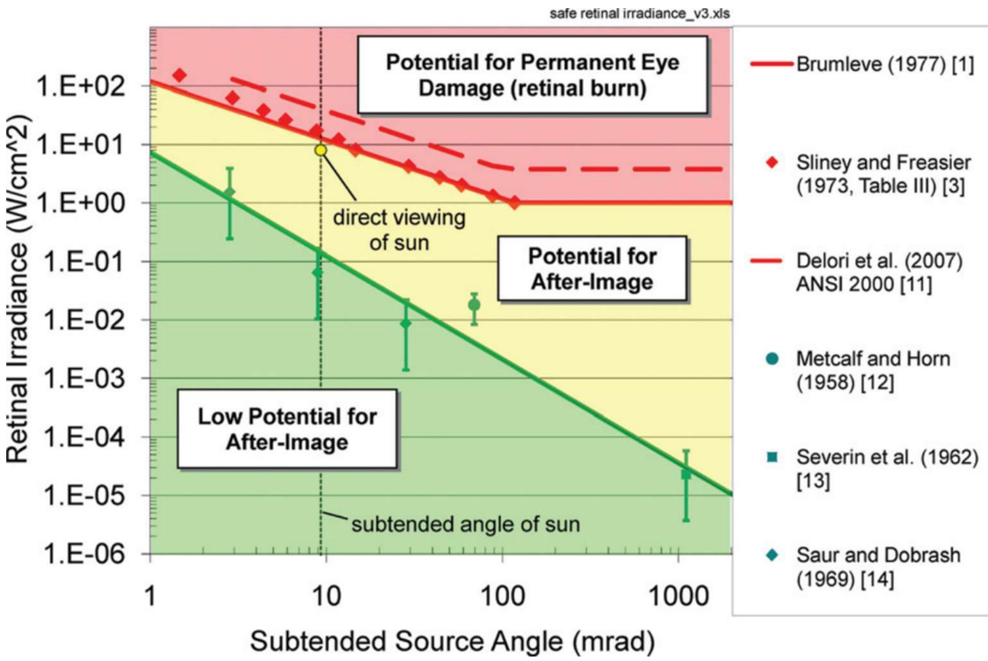


Figure 28. Map of eye hazard potential (from Ho).

The NREL results in the first phase of the study showed that the greatest opportunity for high retinal irradiances was at the summer solstice at noon. Retinal irradiances, $E_{r,d}$, are shown in Figure 29 for the upper spill zone with the boundary line for after-image potential shown. Slope error and spill reflectivity have been combined into a single dimensionless variable for this plot.

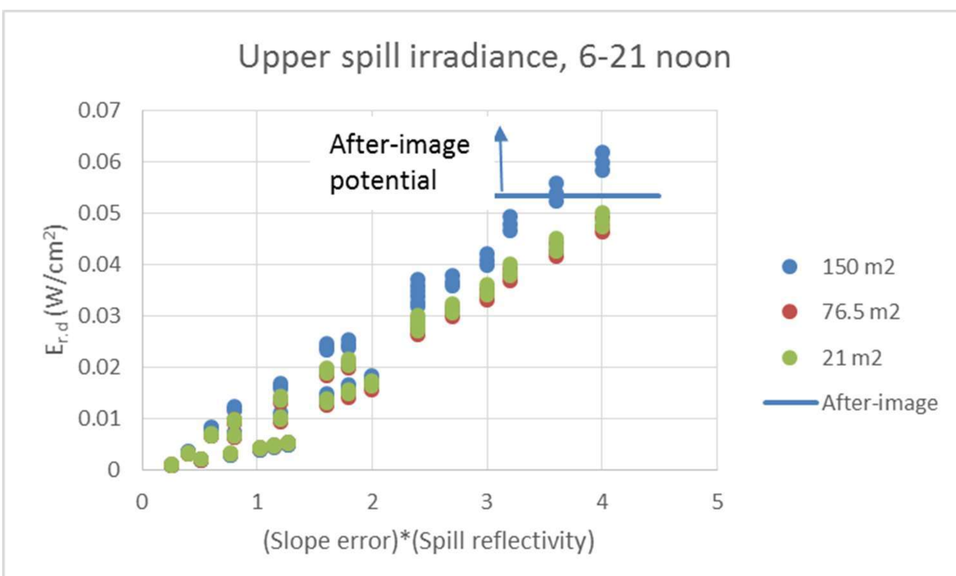
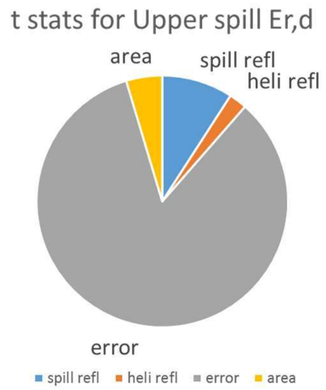


Figure 29. Summer solstice noon results.

The primary influence on spill zone brightness is heliostat slope error followed by heliostat area and spill and heliostat reflectivity, depending on the time of year and time of day. Figure 30 shows a comparison between the major influences on retinal irradiance as described by the *t* statistics calculation performed on the set of results for noon at the winter solstice.



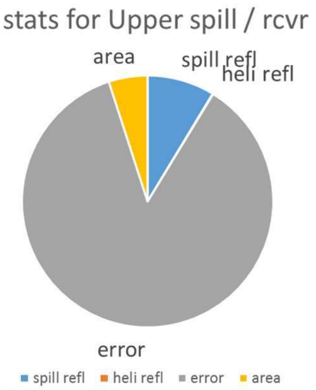
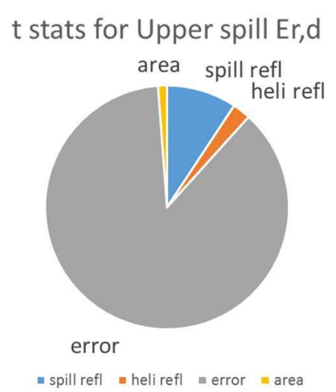


Figure 30 t statistics at noon on the winter solstice.

The left side of the figure shows that heliostat error is the largest influence on spill zone brightness, followed by spill zone reflectivity, heliostat area, and heliostat reflectivity. The right side of the plot shows that the ratio of the upper spill zone perceived brightness to the receiver brightness is influenced by the same variables in the same order with the exception that heliostat reflectivity is insignificant.

In contrast, at the same time of day on the summer solstice, the area variable becomes much less important than in the winter. Figure 31 shows the *t* statistics for noon on the summer solstice.



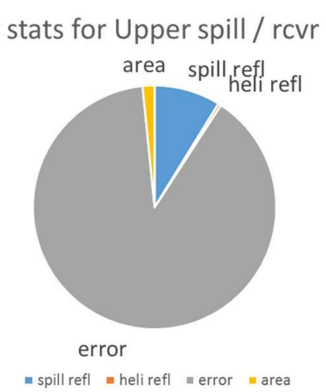


Figure 31 t statistics for noon on the summer solstice.

Also, at three hours away from solar noon the area variable returns to being a significant influence on retinal irradiance. Figure 32 shows the summer solstice *t* statistic results at 9 a.m. and noon.

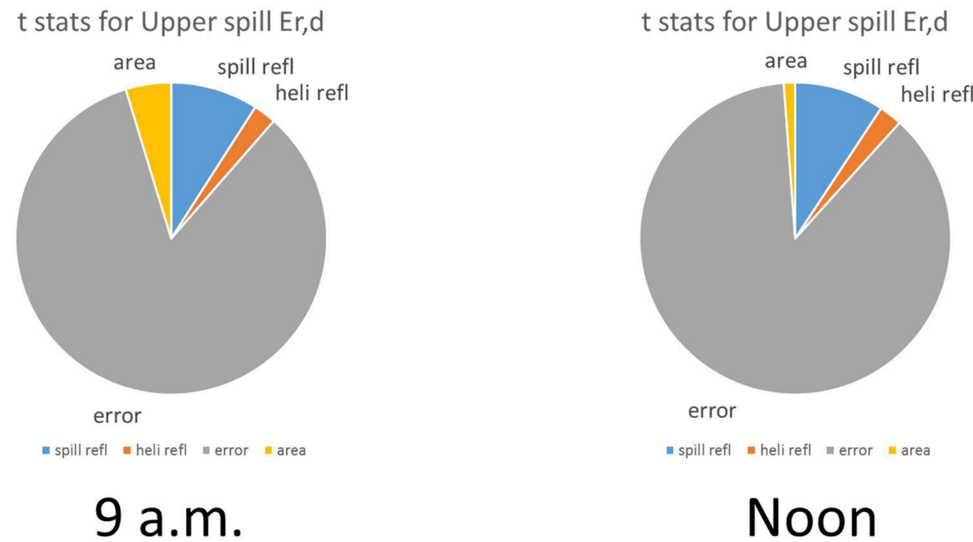


Figure 32 t statistics at two times on the summer solstice.

In general, the influence of area shows that for much of the time when the sun is at lower positions that at noon on the summer solstice maintaining low slope error becomes increasingly important as heliostats increase in size. This has important implications in the development of large heliostat designs.

Figure 33 shows the ratio of irradiance from the upper spill zone and the receiver for the summer solstice as a function of slope error and spill zone reflectivity. The upper spill zone will appear brighter than the receiver at most slope errors shown with high reflectivity surfaces on the spill zones. Only with very low reflectivity surfaces will the spill zone appear as, or less bright, than the receiver with most of the slope errors studied. It's possible to use low reflectivity surfaces, but the high amount of absorbed thermal power will have to be dissipated with a cooling mechanism, either active or passive. Solar Dynamics has studied one active cooling approach, described elsewhere in this report.

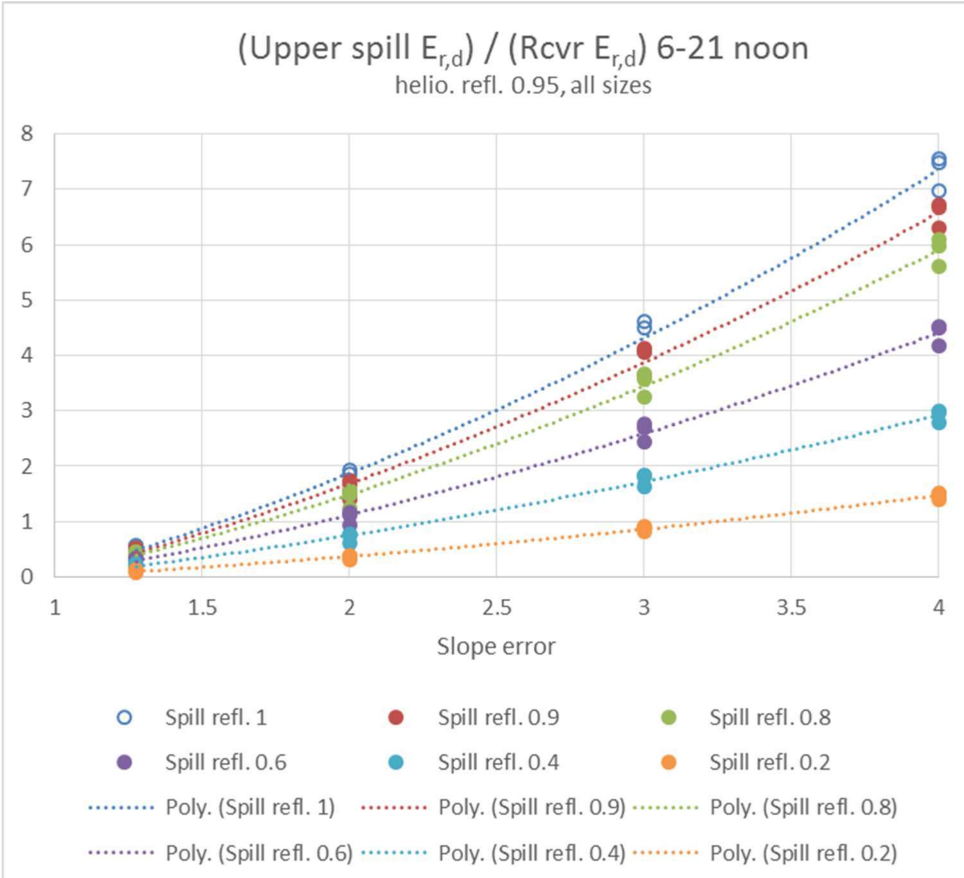


Figure 33 Irradiance ratio as a function of slope error at the summer solstice.

The second phase of NREL's study involved detailed SolTrace analyses of the noon summer solstice flux distributions. Figure 34 shows the results for the case with 21 m^2 heliostat, 1.3 mrad slope error, 0.9 heliostat reflectivity, and 1 spill reflectivity, defined as the base case in the study. The upper and lower spill zones will appear much brighter than the receiver. Elevation denotes distance up the tower, with the lower and upper spill zones clearly bracketing the receiver zone. The zero-circumferential point is the southern point. The increases in flux from south to north are seen as well. Slight asymmetries are due to the presence of an access road through the solar field.

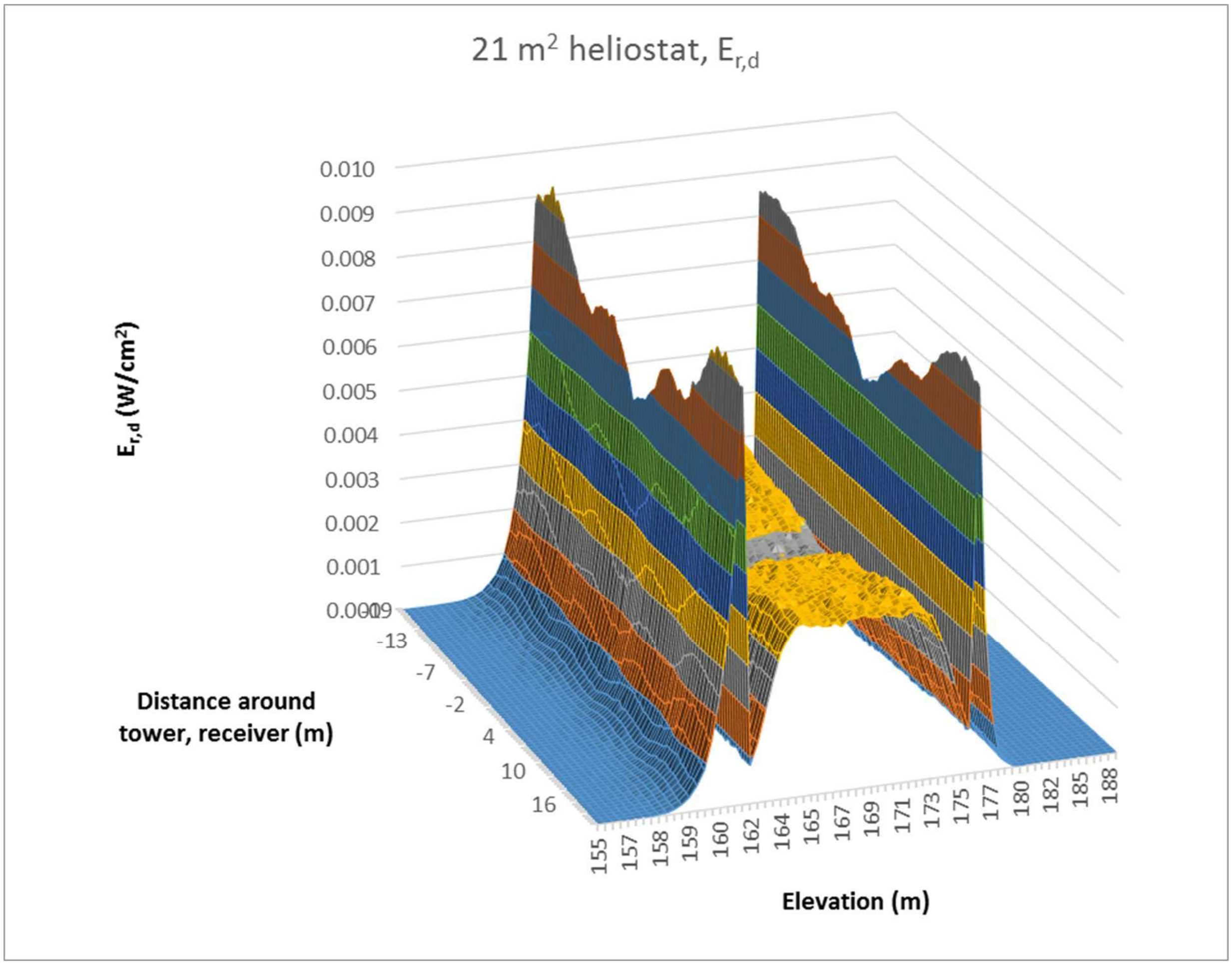


Figure 34 Flux distribution for the base case.

If spill zone reflectivity is reduced to approximately 0.4, the brightness of the spill zones is similar to that of the receiver, as shown in Figure 35.

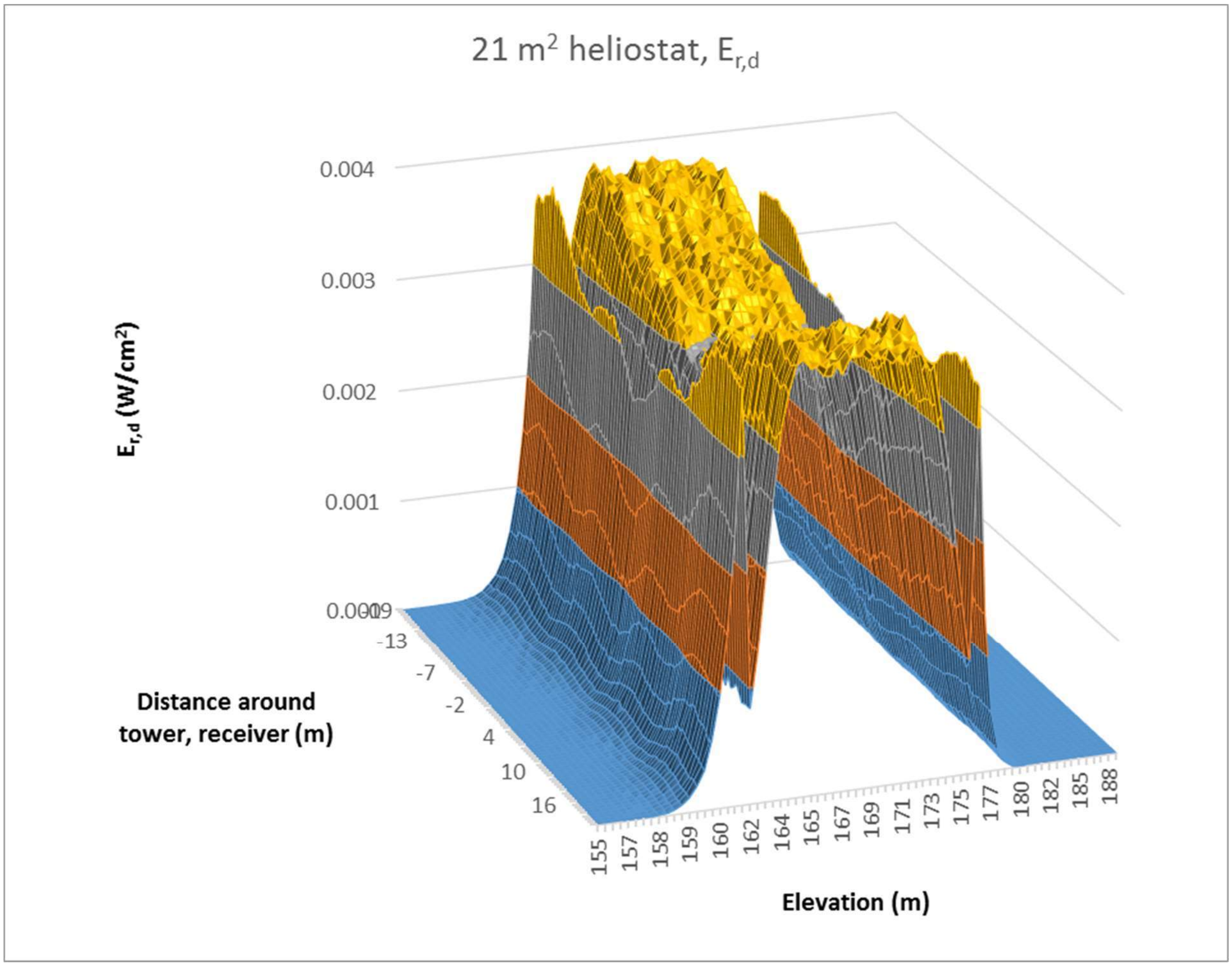


Figure 35 Base case with 0.4 spill zone reflectivity.

If the base case scenario includes high slope error of 4 mrad, all else being equal, the perceived brightness of the spill zones relative to the receiver increases dramatically as shown in Figure 36.

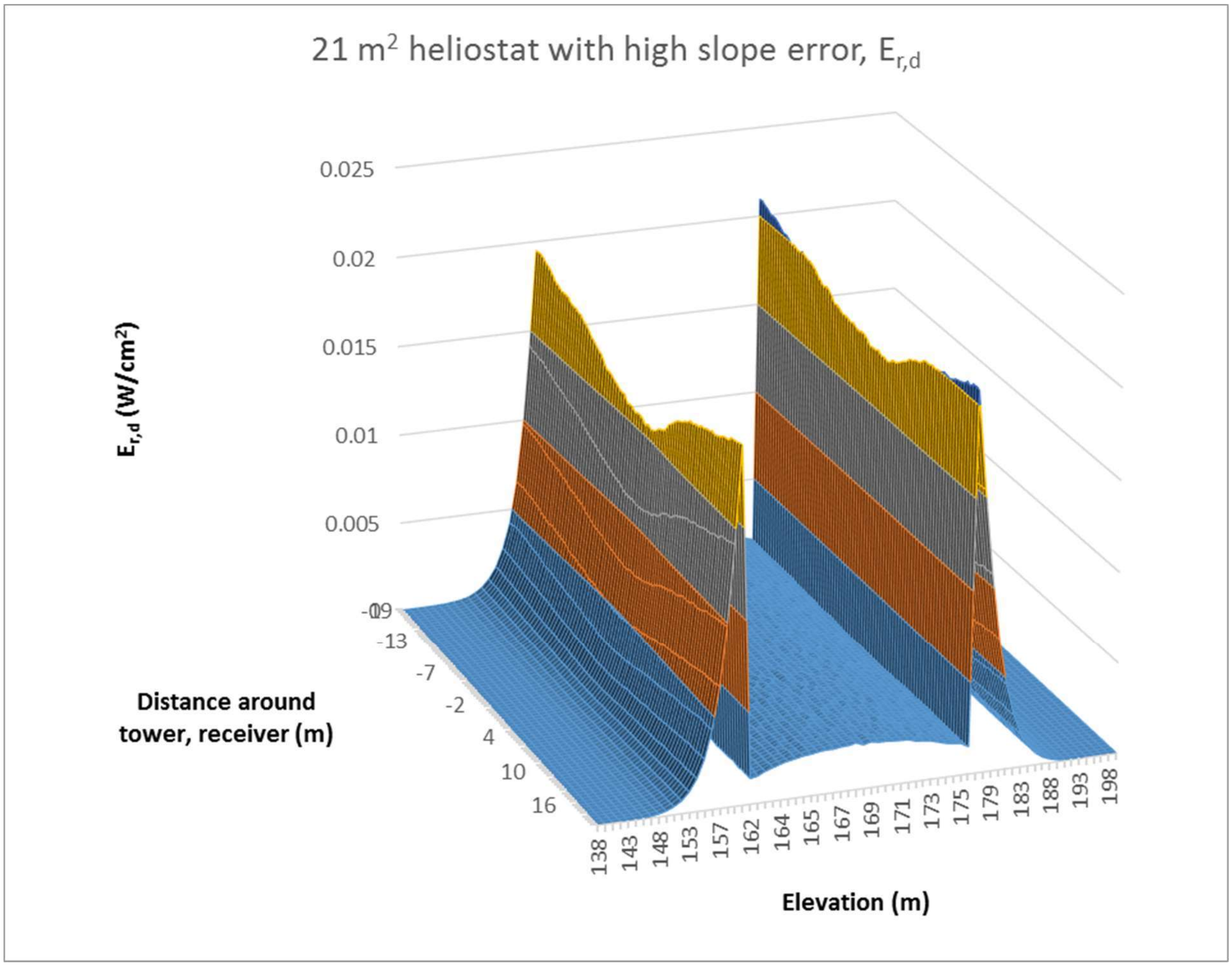


Figure 36 Base case with high slope error and high spill zone reflectivity.

With high slope error heliostats, the spill reflectivity must be reduced to approximately 0.13 in order to reduce the relative irradiance of the spill zones and receiver, as shown in Figure 37.

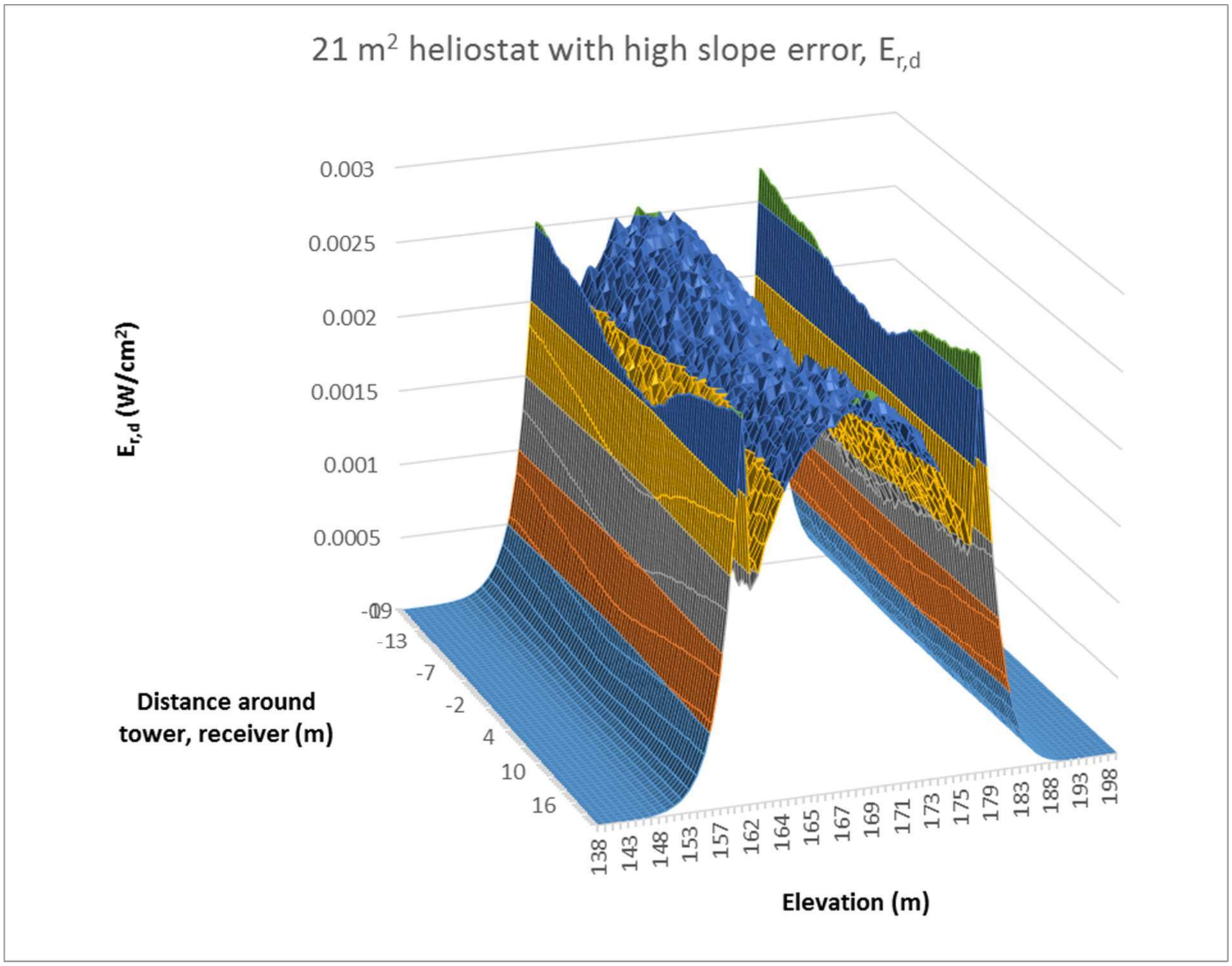


Figure 37 Base case with high slope error and low spill zone reflectivity.

The worst case for relatively high spill zone irradiance is the 150 m^2 heliostat, 4 mrad slope error, 0.95 heliostat reflectivity, and 1 spill reflectivity. The perceived brightness of the spill zones is very high relative to the receiver, as shown in Figure 38.

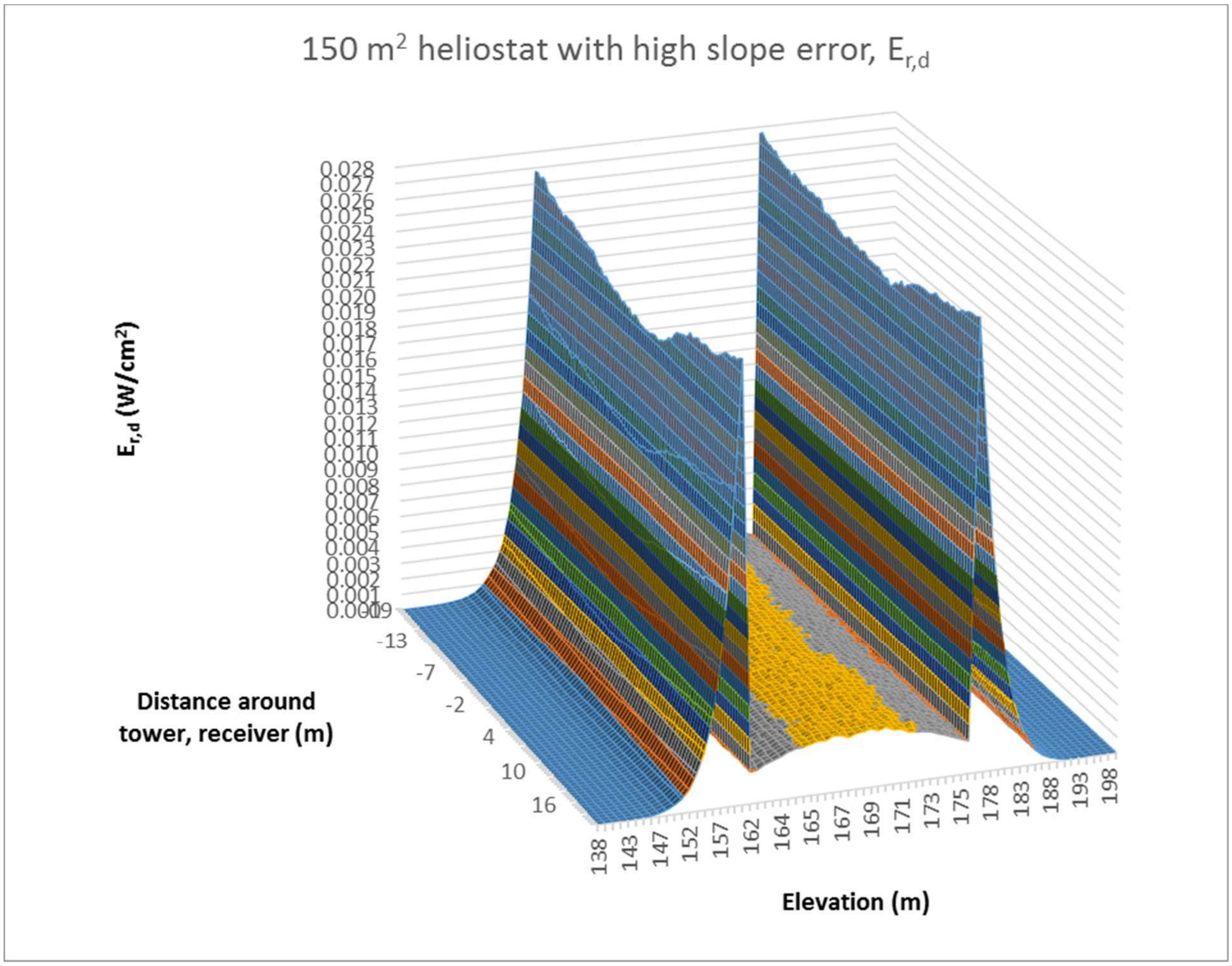


Figure 38 Worse case with high spill zone reflectivity.

As for the small heliostat case, the spill zone reflectivity must be reduced to approximately 0.13 at high slope errors to make the spill zone and receiver appear at the same brightness. Figure 39 shows retinal irradiances at 0.13 spill reflectivity.

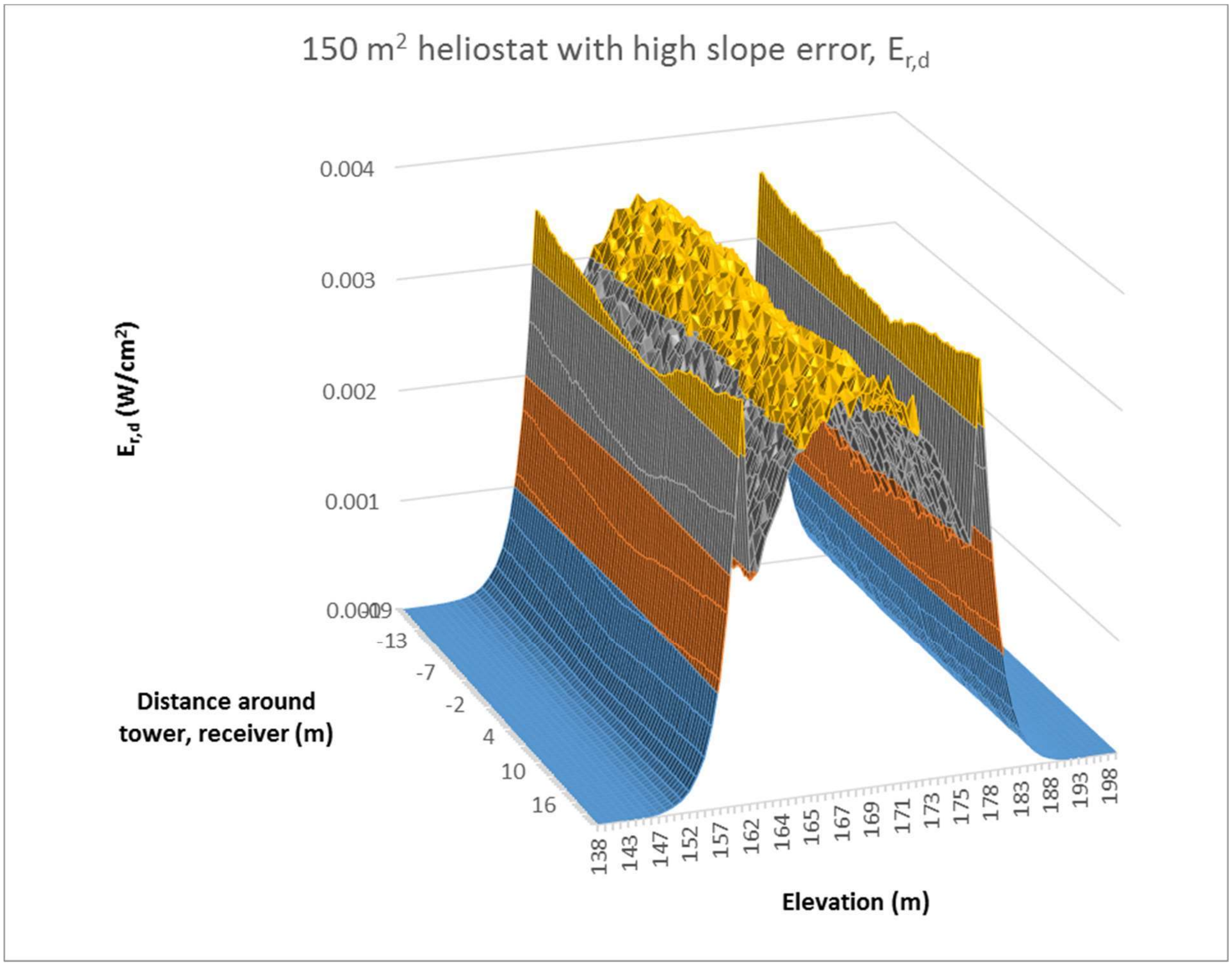


Figure 39 Worst case with low spill zone reflectivity.

In order to reduce the perceived brightness of the spill zones, spill zone reflectivity must be reduced considerably with increasing slope error, and even more so with large heliostats. Low heliostat reflectance, mean high absorptance, thus leading to the need for spill zone cooling techniques. Solar Dynamics has proposed a novel active spill zone cooling method that does not cause large power draws on the plant.

Spill Zone Cooling

The previous study concluded that spill zone brightness must be reduced in order to reduce glare and glint effects. Spill zone brightness is reduced by lowering the reflectivity, and correspondingly increasing absorptivity, of the coatings applied to the spill zones. As spill zone absorptivity rises, active cooling of the panels covering the receiver ovens and tower elements must be incorporated.

As Figure 40 shows, if the spill zone reflectivity is 0.2 or less, the spill zones will generally be less visible than the receiver over a range of slope error up to approximately 3 mrad.

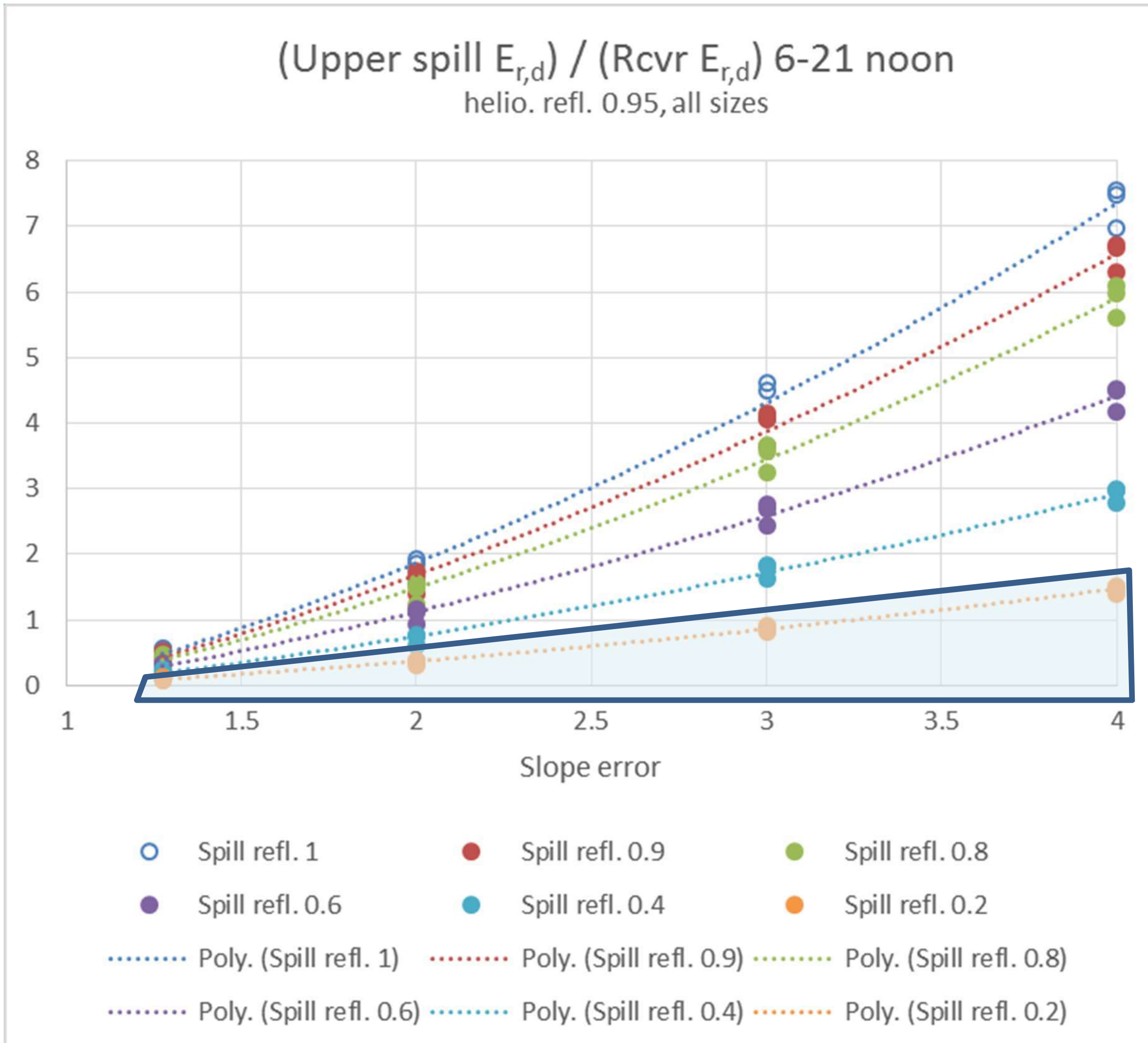


Figure 40 Spill zone reflectivity must be low in order to have the spill zones less bright than the receiver

One method to cool the spill zones is to use make them from perforated sheet metal and to draw ambient air through the perforations. This approach is the same heat transfer mechanism employed in the unglazed transpired collector, which was researched at NREL in the 1990's and also commercialized. The concept behind the unglazed transpired collector is shown in Figure 41. The same approach of a plenum behind the perforated sheets collecting warm air directed to the suction side of a blower exhausting to ambient could be used for spill zone cooling. The perforated sheets can be made of mild carbon steel with a high temperature paint applied to them. There is no need to use high conductance material for the perforated sheets.

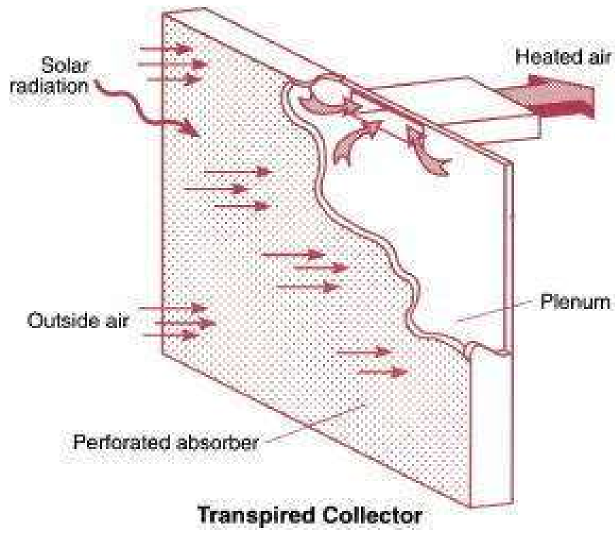


Figure 41 Unglazed transpired collector concept, proposed as cooling method for spill zones (NREL graphic).

With NREL's results for power incident on the spill zones, evaluations were made of the potential blower power needed to maintain the perforated panels below 700°F. This value was chosen because above this temperature mild carbon steel starts to experience changes in physical properties. While some change in crystalline structure, for instance, may not affect the performance of perforated sheets under the low stresses in this installation, the question of raising the temperature limit can be explored in a future study. Plenum depth and porosity were varied in order to minimize blower power and maintain uniform cooling over the perforated sheet surface.

Figure 42 shows the results for blower power as a function of power incident on the upper spill zone using the case with the large heliostat at 0.95 reflectance over a range of slope errors. Table 12 shows the study results in terms of incident flux. Differential pressure across the perforated sheet was kept low by adjusting porosity and plenum depth.

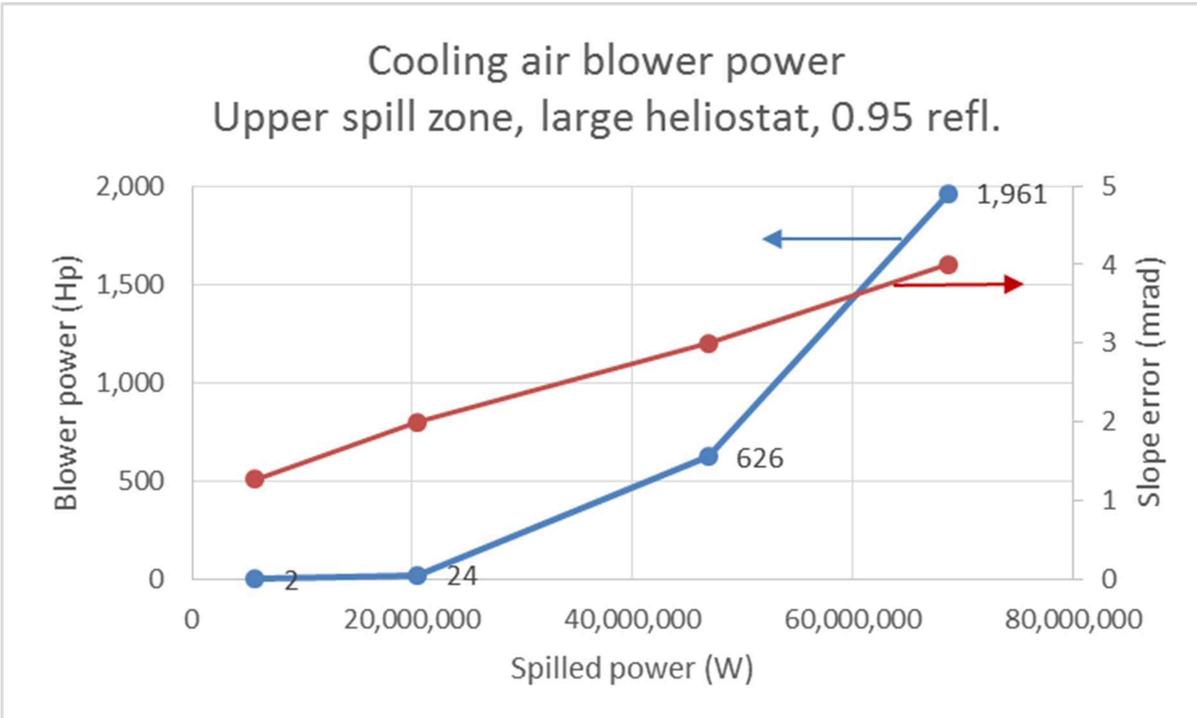


Figure 42 Blower power needed to cool the upper spill zone.

Table 12. Cooling study results.

Incident flux	Cooling air flow	Differential pressure	Blower power
(W/m2)	(cfm)	(in. WC)	(hp)
30,015	41,521	0.26	2.0
106,777	307,561	0.42	24.5
244,263	1,845,365	1.79	626.1
357,688	4,997,864	2.07	1,961.1

Blower power becomes significant at high slope errors and accompanying high spilled power levels. But at slope errors that represent a well-constructed and controlled solar field, blower power is not a large drain on the plant's gross power. The active cooling method may warrant further consideration in future tower studies.

Appendix E – Survey of Southwestern Utilities

A number of utilities in the Southwestern US were contacted and presented information on the molten-salt tower dispatchable solar power plant concept. Utilities were then asked to respond to a survey on their potential interest and perspective on the concept. Responses were received back from four utilities, including Arizona Public Service (APS), Southern California Edison (SCD), Sacramento Municipal Utility District (SMUD), and a fourth utility that provided responses but preferred not to be identified.

Dispatchable Solar Power (DSP) Plant Concept

A molten-salt tower (MST) plant has been designed to operate more flexibly and be able to replace the need for a new natural gas peaking plant, typically a frame or aero derivative combustion turbine. DSP implies that the plant can generally store power during the day for dispatch for non-daylight hours. Peaking assumes 4-6 hrs of daily operation (annual capacity factor of 15 to 25%), intermediate implies more generation per day, maybe 8 to 12 hrs of daily operation (annual capacity factor of 30 to 50%). This plant can also be designed to fill in around PV as a flexible base-load plant (annual capacity factor of 50 – 90%). These plants might range in size from 100-150 MW for the peaker or intermediate load plants and 150-400 MW for the base-load plants.

- Based on the presentation, do you understand the DSP plant application being proposed and how the MS tower plant would be designed and operated for this type of application?

  APS - Yes, understand it very well.

  SCE - Yes, I understand the technology and use cases.

  SMUD - Yes, the basic concept of DSP is understandable, and we have general familiarity with similar plants existing in the western United States.

  Utility #4 - Yes I do understand. For the most part it will be using existing technology and design it as a peaking fast start unit.

- Over the next 10 years, do you see the need for new peaking generation resources? Or other generation resources? What kind(s)?

  APS - Yes. For our utility located in the desert SW, that is really our only need in the next 10 years.

  SCE - I see a large need for clean generation and clean ramping resources in the state of California.

  SMUD - We see the need for peaking resources, whether they are derived from PPAs where the services are imported into our service territory or they are associated with in-service-territory facilities.

Utility #4 - I see in the next 10-years a higher demand for peaking units. This can come from existing simple cycle units or renewable sources such as DSP, PV/batteries or combined cycle/battery hybrids.

- Do you think the DSP plant could meet some of those needs for new peaking capacity?

  APS - I think on paper the DSP will meet the needs, but the technology will need to be reliable and competitive with not only the current market conditions but also future market where batteries are more cost efficient.

  SCE - Yes, I believe the technology could meet those needs.

  SMUD - Potentially yes, depending on a number of factors answered later in this questionnaire.

  Utility #4 - Yes. Since the presentation used our needs as an illustration, I think that the design example in the presentation does an excellent job of meeting that need. The real question is in ability to achieve pricing that is competitive with other options for meeting that need.

- What must a DSP plant compete with in the future (next 5-10 years)?

  APS - In the next 5-10 years I see DSP plants competing with the initial proliferation of PV/battery technology plants, existing simple cycle plants and the installation of more efficient simple cycle. I also see a broader market base for wholesale energy to meet import demands for states with high RPS requirements, which would compete with DSP value.

  SCE - Batteries, pumped hydro, solar PV, wind, and geothermal.

  SMUD - DSP plants must compete with other means of aiding the integration of variable resources, including use of conventional hydro (with reservoir storage) and demand response programs and potentially but less likely, reciprocating engine plants.

  Utility #4 - See previous question. Clearly a question of cost but there may also be some questions related to technology viability and demonstration (although that question may get answered by projects that are moving forward in other parts of the world).

- Does a carbon free flexible peaking plant look interesting to you?

  APS - It does, because it provides a real market need for flexing units that can be dispatched and it provide a clean energy option to meet future RPS needs for the utility industry.

  SCE - Yes, I am very interested.

SMUD – Yes.

Utility #4 - Yes. However, another important aspect is in resource diversity and lessening the dependence on natural gas (and related infrastructure) to meet those peaking needs.

- What would motivate you to add a DSP plant to your generation resources in the next 5 years?

  APS - Generation cost, reliability, dispatch flexibility, RPS credit, scalability.

  SCE - The ability to successfully compete in a competitive solicitation for new, flexible gen resources in the state of California.

  SMUD - A number factors would motivate our decision to add a DSP plant. The primary motivator would be competitive economics compared to alternative generation resource (i.e., competitive LCOE), which includes a combination of competitive construction costs, competitive environmental mitigation costs, reliable estimates of availability and generation, and competitive O&M costs. The additional generation associated with the storage component of a DSP, along with other values such as capacity, would be weighed against the additional expense of the component.

  Utility #4 - It would most likely be a function of price competitiveness as we are required to use competitive procurement processes to meet these types of needs.

- Do you believe that outreach to key stakeholders in target states is needed to enable a market for DSP peakers and intermediate plants? If so, to whom?

  APS - Yes, I think an outreach to the key stakeholders would be key. It would have to start with the independent system operator and the regulatory commission to drive partnership between a utility and government.

  SCE - You need to make a case to the CPUC, CAISO, and CEC that this technology is cost-competitive. The CPUC essentially excluded this technology from the set of available resources in the current IRP proceeding because the perceived cost of the technology was far too high when compared with solar and battery storage. In the most stringent carbon case, pumped storage was selected as the next choice for a flexible, clean resource. There is a serious disconnect with the analysis that NREL is performing and the perceptions of CA regulators around this technology. This technology is about to miss a gold rush because the analysis is misunderstood. I suggest that it is time to start comparing costs (plant and overall system) rather than value as calculated by estimated revenue.

  SMUD - It depends on the technologies of the DSP plants. If the DSP plant is a conventional solar panel generation facility with battery storage, we don't think the battery storage concept would require outreach to new stakeholders. However, our understanding is that DSP plants using heliostats and towers with molten salt have struggled in their initial years of operation, based on issues of glint/glare, avian mortality, natural gas use, and water use. Thus, key stakeholders might include environmental NGOs, resource agencies, and the public who are concerned about these issues which are not as concerning for a conventional solar panel facility.

Utility #4 - Speaking for this utility, I feel like we have a very good understanding of this technology so not certain that the outreach would be needed for us.

- Do you currently have a mechanism to procure a DSP plant or power from a DSP plant?

  APS - We currently setup purchase power agreements for renewable energy, and depending on the wording of the contract, a DSP could bid. The agreement would be subject to legal, commercial and reliability terms of the contract.

  SCE - In the not-so-distant (2-5 years, -15 years) future A LOT of clean generation will be procured for the state of California. This will be accomplished through competitive solicitations, I believe there is a real demand for this technology but it is imperative that those bids be cost competitive with other clean, flexible technologies.

  SMUD - Yes, we regularly enter into PPAs to procure power from solar facilities which could be a dispatchable facility. We also enter into contracts for entities to construct power generating facilities that SMUD owns and either operates or contracts out for O&M services.

  Utility #4 - Yes. It would have to occur via a competitive RFP process that we would utilize to meet our future peaking resource needs.

Technology – Molten Salt Tower (MST)

- Are you familiar with molten-salt technology?

  APS - Yes. Very familiar given our role with Solana.

  SCE – Yes.

  SMUD – Yes.

  Utility #4 - Yes, I have familiarity with molten-salt technology.

- Technology Maturity – How many MS tower plants would need to be built globally before you would feel comfortable relying on an MST?

  APS - At least one at a reasonably large scale.

  SCE - I'm not sure we view the MS technology or any technology in this way.

  SMUD - While molten salt is not a novel technology, the application of MS coupled with solar generation is fairly new and untested. We would want to see a number of plants built throughout the world with approximately 10 years of demonstrated reliability before we would likely invest in the technology. One of the difficulties we have heard of related to this technology is the complexity of coordinating hundreds of heliostats, each with different orientation requirements. Another difficulty is the requirement or need to curtail generation, or heating of the tower, when birds fly into the area of sun concentration.

Utility #4 - It is difficult to put a number but I would say at least 3-5 units that have at least 3-5 years of reliable operation.

- Technology Suitability for peaking application – Assuming that MST technology were sufficiently mature, are you comfortable that that it could be used for the DSP plant type application?

  APS - Yes.

  SCE – Yes.

  SMUD – Yes.

  Utility #4 - I would be comfortable with DSP application since the application of the molten salt technology would have matured, the heat source from molten salt is available for dispatch, and the steam cycle technology has been established for a long time.

- Technology Performance – How many years of performance data (and at what reliability and availability) would you need to see before purchasing the output from a MST plant?

  APS - We don't have a specific number but it would have to be at least a couple of years. I don't believe that you can look at this answer in isolation from considerations such as cost and size. For instance, we may be willing to take on more risk if the economic payoff is promising and/or the size is relatively small compared to our overall size.

  SCE - I'm not sure we view the MS technology or any technology in this way.

  SMUD - Approximately 10 years of performance would be needed.

  Utility #4 - 3-5 years of continuous service is probably a good number. In addition to performance data, there would be contractual obligation that should be met after the demonstration.

- The following are the proposed operational characteristics for a DSP plant, are these reasonable to get your interest in adding it to your generation fleet?
  - Start to minimum load time: <10 minutes
  - Start to full load time: 30 minutes
  - Ramp up and ramp down rate: 10%/minute

APS - we can manage with all of those parameters but I don't believe that they are all necessary. We don't need a resource like this for contingency response purposes. We can schedule it for normal runs across our evening peak period on a routine basis. We believe that we have enough quick-start to handle contingency response and would likely trade-off the quick-start parameters above if it brought the overall costs down.

SCE - Since we are not a potential owner, we would procure through a energy/capacity/flex capacity competitive solicitation. Each of the above represents characteristics which we believe will be in great need in the coming decades.

SMUD - Yes, while these operational characteristics are a bit slower than our current thermal peaking units, they are within a suitable range.

Utility #4 - This would be very reasonable to add to our generation portfolio subject to meeting requirement for availability and reliability. The units should operate in AGC mode so the balancing authority can change load as necessary.

- Performance Wrap – Are you concerned about finding a developer able to provide an acceptable performance guarantee?

APS - Yes. This is an important element of project viability. However, in a PPA structure we would an appropriate pricing structure that strongly aligned the financial incentives of the developer/owner with our needs.

SCE – Yes.

SMUD - Yes, because of the limited number of MST projects with extensive operational timeframes.

Utility #4 - If the technology has been proven, cost effective and there are contractual obligation by both parties to meet performance guarantees than the concern is reduced. However, even with all framework in place to shift or reduce risk, there will be a concern for becoming an early adopter of DSP without the backing of the regulatory commission, government and the independent system operators.

- Reliability – Are there any start-up and operational performance concerns that you have regarding MST?

APS - Nothing other than normal concerns related to demonstration at scale for this technology.

SCE - Not specifically.

SMUD - We are concerned with the amount of salt that would be needed to replenish that used in the plant, as the efficiency of energy storage is known to diminish over time.

Utility #4 - I think if the operational characteristics are met reliably as stated in pervious question, then the operational concerns would be insignificant.

- Availability – What level of availability is required for a peaking plant?

  APS - Definitely has to be above 95%.

  SMUD - 98% (less than 2% equivalent forced outage factor).

  Utility #4 - 98% availability would be ideal.

- MST Cost – Do you believe that it is appropriate to compare the capacity cost for a DSP plant to that for a natural gas plant?

  APS - Yes. This is our default measuring stick for satisfying our peaking needs.

  SCE – Yes.

  SMUD - Not sure.

  Utility #4 - Yes, since DSP plant will most likely be replacing natural gas "peaking" plants.

- Do you believe that battery technology plus PV and power electronics will be a cheaper or better solution, if so why and when?

  APS - This remains to be seen but holds promise. We are watching these developments closely. We are somewhat technology agnostic and are just looking for the best technologies to meet our customer needs.

  SCE - Yes, batteries are the primary technology against which MST will be compared in California. There will not be any additional gas generation built in the state beyond what has already been contracted (OTC).

  SMUD - In general, we believe that PV linked to batteries with power electronics will be a likely better technology given some of the uncertainties.

  Utility #4 - I think that battery technology plus PV will most likely be the cheaper technology based on the current strong drive from industry leaders to scale-up this technology. Current DSP plant should be modeled such that it can compete with 5-10 year projected cost of solar + PV.

- What is the maximum PPA term your company would offer (15, 20, 25 or 30 years)?

  APS - This is a moving target. We have done 30-year PPA's in the past. However, things are changing quickly in our industry given the magnitude of the penetration of customer-sited generation and other technologies. In response to these uncertainties, our preference is certainly trending towards shorter terms.

SCE - Generally, 20 years is the maximum length of a PPA.

SMUD - We are generally considering PPAs for solar facilities currently in the range of 25 years.

Utility #4 - 25-30 years.

- Would you be comfortable offering a tolling agreement type PPA for a solar plant?

  APS - We have given this question a lot of thought over the last couple of years. Given the current level of maturity of the solar plus storage technologies, our preference at this time is to use energy pricing in a PPA to help align developer incentives with our needs.

  SCE - Creative solutions to difficult problems are always welcome.

  SMUD - We don't have enough experience with tolling agreement to answer this question.

  Utility #4 - Probably not since we have to build a portfolio of generating units that meets the needs of our customers. Tolling agreement, in my opinion, would be very similar to buying power in the open market.

- Are you interested in a BOOT option?

  APS - Not at this time.

  SCE - In California the utilities generally don't own where competitive markets can provide solutions.

  SMUD – I am unfamiliar with the acronym "BOOT".

  Utility #4 - In my opinion our utility is not interested in a BOOT.

- Do you see permitting challenges unique to towers, other permitting challenges?

  APS - Yes. There are clearly some in our area given military flight paths.

  SCE - Yes, there seems to be challenges to permitting any large scale generation, *renewable or not, in the state of California.*

  SMUD - Permitting challenges that are unique to towers are generally associated with environmental impacts, which may include avian mortality (take permits) and water use (water quality certification).

  Utility #4 - There will be permitting challenges, but this is not the first time that a CSP has been built in Nevada or California.

- Public Reaction – What public reaction concerns do you have re MST - visual, birds, other?

  APS - I think that all of these concerns are manageable.

  SCE - There could be significant negative public reaction to MST for those reasons and more.

  SMUD - Glint and glare, avian mortality, and visual impact, as well as land-based habitat impacts on terrestrial species.

  Utility #4 - I would expect that the public reaction would be very similar to Tonopah or Ivanpah solar facilities.

- What do you see as the most important issues facing MST technology?

  APS - I think that it is cost and maturity of technology.

  SCE - Cost versus batteries and PV.

  SMUD - The need to compete economically with other means of providing flexible generation to meet the up-ramps associated with the "duck curve", such as battery storage, demand response, and conventional hydro with reservoir storage.

  Utility #4:
    - Competition from PV + battery technology
    - Market competition from simple cycle units
    - More efficient and lower installed cost thermal generating technologies
    - Reliability concerns for existing MST facilities
    - Slow proliferation and development of new MST plants
    - Successful demonstration of DSP application
    - Utilities willingness to take risk for initial market demand
    - Large initial capital investment and financial backing

- What concerns you the most about using MST technology for the DSP application?

  APS - Same as above. We will need to see some at-scale demonstration along with having developers who clearly have the financial wherewithal to overcome the inevitable challenges of making this technology work at high availability factors.

  SMUD - We view this technology as in a developmental phase, with limited applications that provide a sense of their long-term viability. While the technology makes general sense, there is insufficient information to judge its cost-competiveness, concerns about reliability given the mechanical complexity of independent heliostat settings, and curtailment during bird migration.

  Utility #4 - would lump the answer for this question with the question above.

Rank the importance of the following topics and your level of concern with the current state.

Utility #4

	1 not important / 5 very important					1 not a concern / 5 very concerning				
MST Technology Maturity	1	2	3	4	**5**	1	2	3	**4**	5
MST Plant Availability	1	2	3	4	**5**	1	2	3	4	**5**
MST Plant Operability	1	2	3	4	**5**	1	2	3	**4**	5
MST Plant Performance	1	2	3	4	**5**	1	2	**3**	4	5
Correlation between solar & peak load	1	2	3	**4**	5	1	2	**3**	4	5
Hybrid (fossil) backup of DSP	1	2	**3**	4	5	1	2	**3**	4	5
MST Plant Capital Cost	1	2	3	4	**5**	1	2	3	4	**5**
MST Plant O&M Cost	1	2	3	4	**5**	1	2	3	4	**5**
Project Schedule	1	2	3	4	**5**	1	2	3	4	**5**
EPC Construction Schedule	1	2	3	4	**5**	1	2	3	4	**5**
EPC Wrap Warranty	1	2	3	4	**5**	1	2	3	**4**	5
MST Plant Permitting	1	2	3	4	**5**	1	2	**3**	4	5
Avian Concerns	1	2	3	**4**	5	1	2	3	**4**	5
Visual Impacts	1	2	**3**	4	5	1	2	**3**	4	5
Siting of towers (FAA/DOD)	1	2	3	**4**	5	1	2	**3**	4	5
Siting other concerns	1	2	3	**4**	5	1	2	**3**	4	5
Water Usage	1	2	3	4	**5**	1	2	3	**4**	5
Project Economics	1	2	3	4	**5**	1	2	3	4	**5**
Bankable PPA	1	2	3	**4**	5	1	2	**3**	4	5
Financing – Debt	1	2	**3**	4	5	1	2	3	4	**5**
Financing – Equity	1	2	**3**	4	5	1	2	3	4	**5**
Financing – Tax Equity	1	2	**3**	4	5	1	**2**	3	4	5
ITC Expiration	1	**2**	3	4	5	1	2	**3**	4	5
Other ______________________	1	2	3	4	5	1	2	3	4	5

Mark which markets you think a DSP plant could compete in

Markets	Time Period 2020	2030	2040
DSP plant – peaker application	●	●	○
DSP plant – intermediate load	○	○	○
DSP flexible Baseload	○	○	○
Other - describe(Solar/PV)	●	●	●

Rank the importance of the following topics and your level of concern with the current state.

SCE

	1 not important 5 very important	1 not a concern 5 very concerning
MST Technology Maturity	1 2 3 4 5	1 2 3 4 5
MST Plant Availability	1 2 3 4 5	1 2 3 4 5
MST Plant Operability	1 2 3 4 5	1 2 3 4 5
MST Plant Performance	1 2 3 4 5	1 2 3 4 5
Correlation between solar & peak load	1 2 3 4 5	1 2 3 4 5
Hybrid (fossil) backup of DSP	1 2 3 4 5	1 2 3 4 5
MST Plant Capital Cost	1 2 3 4 5	1 2 3 4 5
MST Plant O&M Cost	1 2 3 4 5	1 2 3 4 5
Project Schedule	1 2 3 4 5	1 2 3 4 5
EPC Construction Schedule	1 2 3 4 5	1 2 3 4 5
EPC Wrap Warranty	1 2 3 4 5	1 2 3 4 5
MST Plant Permitting	1 2 3 4 5	1 2 3 4 5
Avian Concerns	1 2 3 4 5	1 2 3 4 5
Visual Impacts	1 2 3 4 5	1 2 3 4 5
Siting of towers (FAA/DOD)	1 2 3 4 5	1 2 3 4 5
Siting other concerns	1 2 3 4 5	1 2 3 4 5
Water Usage	1 2 3 4 5	1 2 3 4 5
Project Economics	1 2 3 4 5	1 2 3 4 5
Bankable PPA	1 2 3 4 5	1 2 3 4 5
Financing – Debt	1 2 3 4 5	1 2 3 4 5
Financing – Equity	1 2 3 4 5	1 2 3 4 5
Financing – Tax Equity	1 2 3 4 5	1 2 3 4 5
ITC Expiration	1 2 3 4 5	1 2 3 4 5
Other ______________________	1 2 3 4 5	1 2 3 4 5

Mark which markets you think a DSP plant could compete in

Markets	Time Period 2020	2030	2040
DSP plant – peaker application	○	○	○
DSP plant – intermediate load	○	○	○
DSP flexible Baseload	○	○	○
Other - describe	○	○	○