 

Concentrating Solar Power Best Practices Study

Mark Mehos,[1] Hank Price,[2] Robert Cable,[2] David Kearney,[2] Bruce Kelly,[2] Gregory Kolb,[2] and Frederick Morse[2]

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2 Solar Dynamics, LLC

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Technical Report
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Foreword

The concentrating solar power (CSP) industry has its roots in the LUZ parabolic trough developments in California that started in the 1980s. LUZ built nine plants that demonstrated the early commercial implementation of CSP technology, providing an important source of knowledge for future CSP system development. Over the last 15 years, the CSP industry has emerged and evolved into a global industry and supply chain. CSP plants have been built in 12 different countries, with the industry now—in 2020—approaching 100 plants in commercial operation.

Many companies, laboratories, institutions, and individuals have played important roles in the development and growth of this renewable source of electricity. Much learning and experience has occurred, although significant portions of this knowledge have remained internal to specific companies due to commercial interests or, in some cases, insufficient platforms suitable for sharing valuable insights. As a result, our observation is that too many lessons have had to be relearned as new plants are designed and built by new participants. Therefore, the purpose of this report is to gather valuable knowledge from the experiences of industry and stakeholders.

This report is titled *CSP Best Practices*, but it can be more appropriately viewed as a mix of problematic issues that have been identified, along with potential solutions or approaches to address those issues. In some cases, but not all, the solutions are in fact best practices. But in other cases, they may be more accurately viewed as practices valuable for consideration or as innovative but unproven ideas to solve problems or improve operations.

The report relies heavily on the feedback we have received from the CSP stakeholders interviewed in this process. We have chosen to lean on the side of sharing detailed information as well as synthesizing it into brief best practice recommendations. Many problems have been project-specific but reflect broader significance. Furthermore, a few reviewers pointed out that some of the issues chosen for inclusion are not CSP-specific, but rather are general issues common to any complex construction project of this nature. This is true, but we include them in sections of the report because such issues are vitally important to successfully develop CSP projects. Thus, to provide a broader understanding for future CSP stakeholders, our overall approach has been to address observations from stakeholders on common issues and experience related to developing and executing CSP projects.

Our aim is that the reader will find the information presented here to be useful and thought-provoking, with ample examples that can serve to develop stronger CSP projects with lower project costs and improved long-term plant operation.

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Section 5 – Parabolic Trough:	Georg Brakmann, Miroslav Dolejsi, Martin Eickhoff, Antonio Gavilan, Anne Schlierbach, Eduardo Zarza
Section 6 – Central Receiver:	Raul Navio, Jim Pacheco

List of Acronyms

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BOO	build, own, and operate
CAPEX	capital expenditure
COD	commercial operation date
CSP	concentrating solar power
Cv	flow coefficient
DCS	distributed control system
DLR	German Aerospace Center
DNI	direct normal insolation
DOE	U.S. Department of Energy
EPC	engineering, procurement, and construction
FAT	final acceptance test or factory acceptance test
FEED	front-end engineering design
FIT	feed-in tariff
FSC	field supervisory controller
HAZOP	hazard and operability
HCE	heat-collection element
HTF	heat-transfer fluid
I&C	instrumentation and control
IEA	International Energy Agency
IA	Initial acceptance
IE	independent engineer
ISCC	integrated solar combined cycle
KPI	key performance indicator
LE	lender’s engineer
LCOE	levelized cost of electricity
LD	liquidated damage
LNTP	limited notice to proceed
LOC	local controller
LOPA	layers of protection analysis
LOTO	lock out tag out
LTA	lender's technical advisor
LTSA	long-term service agreement
MCC	motor control center
MW	megawatt
MW_e	megawatt-electric
MW_t	megawatt-thermal
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NTP	notice to proceed
O&M	operations and maintenance
OE	owner's engineer
OPEX	operating expenditure
OS	out-of-service

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OTS	owner's technical specifications
PLC	programmable logic controller
PM	preventative maintenance
PPA	power purchase agreement
PV	photovoltaic
QA	quality assurance
QC	quality control
RFP	request for proposal
RTD	resistance temperature device
SEGS	Solar Electric Generating System
SETO	Solar Energy Technologies Office
SGS	steam generation system
SME	subject-matter expert
SolarPACES	Solar Power and Chemical Energy Systems
TES	thermal energy storage
TMY	typical meteorological year
UPS	uninterruptable power supply
VFD	variable-frequency drive
VOC	volatile organic compound

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Executive Summary

The primary objective of this Concentrating Solar Power Best Practices Study is to publish best practices and lessons learned from the engineering, construction, commissioning, operations, and maintenance of existing concentrating solar power (CSP) parabolic trough and power tower systems. To accomplish this objective, information was solicited from many owners, operators, and engineering, procurement, and construction (EPC) contractors, independent engineers, and other stakeholders of parabolic trough and central receiver plants (also commonly referred to as power towers). Information was gathered through in-person or online meetings, site visits, and questionnaires sent to participants.

The project team held about 50 information-gathering sessions with participants over the course this effort; and in the process, it collected information from participants representing nearly 80% of CSP plants operating worldwide. An unanticipated outcome of this project has been the extent to which non-technology "project implementation"-related issues have been raised by a majority of the participants interviewed. These project issues have been challenges faced prior to actual operation of the plant, and they represent a significant portion of the total issues experienced. Challenges associated with the steam generation system are faced by both parabolic trough and tower technologies. Apart from the steam generation system challenges, trough systems are predominantly operating with high availability, although maintenance of certain components continues to challenge plant operators. Given the nascent state of tower technologies relative to troughs, the current reliability of these systems is less demonstrated, with the primary challenges raised by participants being associated with salt-related systems (heat trace, valves, receiver, storage). These challenges and their mitigation measures, where identified, are extensively documented in the body of this report.

Based on our finding, the authors are confident that future tower and trough plants can be built on time and within budget and will perform as expected. To accomplish this outcome, the following practices are recommended.

- Accurate solar and wind resource assessment of the site is essential. This includes 5- to 10-minute resolution for solar data, atmospheric attenuation for central receiver projects, and peak and average wind speeds, as well as a reasonable estimate of mirror soiling rates and achievable mirror cleanliness.

- The industry needs to use performance models that accurately model the operation of the plant accounting for transient behavior of the plant, include start-ups, shut-down, intermittent clouds, and operational transitions. Ideally, these models should be provided by independent third parties that are transparent, have been independently validated, and are accepted by the financial community.

- Plants and equipment must be designed for the transient behavior that they will see. Plants can cycle multiple times a day. So plant designs need to understand allowable equipment temperature gradients and make sure that the design of the plant prevents those gradients from being exceeded.

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- We believe the few remaining technology issues for parabolic trough and molten-salt tower projects are actually design issues that can be resolved by appropriate engineering and equipment selection by an experienced team.

- EPCs should continue to improve designs and equipment selection based on experience at operational plants and careful technology innovations.

- Not all collector or heliostat technology is the same. Although few participants considered collector or heliostat technology to be a significant issue, collector/heliostat technology can make or break a project, and many providers have learned much over the last 10 years. The recommendation is to go with a collector/heliostat manufacture/design with a proven track record or to make sure that proper due diligence and testing is done in advance of financial close.

- More attention to control systems and automation of the plant is needed than has generally been practiced by most EPCs in the past. This focus directly affects plant reliability, performance, and cost.

- Active participation and detailed knowledge by the owner's team have been shown to lead to more successful projects. The owner's team should prepare an appropriately detailed owner's technical specification to be included in the EPC contract that details the key requirements and features of the plant. The industry might benefit from a standard and publicly available owner's technical specification, which could be developed by the industry and CSP stakeholders to capture lessons learned for future projects.

- The owner should hire an experienced independent engineer/owner's engineer to support them during all phases of the project. It is important that the independent engineer and owner's engineer both play an active role in the project.

- Appropriate attention to quality assurance/quality assessment and active owner supervision of all stages of the EPC work are essential. Quality assurance/quality assessment is especially important on key pieces of equipment such as heat exchangers, turbines, and pumps.

- Owners should hire an experienced operations and maintenance (O&M) contractor to operate the plant. It is critical that the O&M contractor is mobilized and trained in time to take over the operation of the plant at initial acceptance. It is also a best practice to begin integrating the O&M team early in the EPC process to make sure engineering and procurement decisions can benefit from O&M knowledge. Many participants recommend that the O&M company operates the plant under the supervision of the EPC during commissioning.

- This report is not able to delve into the detailed engineering of a CSP plant. To avoid performance issues, it is essential that a project team has extensive experience and knowledge of CSP technology and a track record of implementing practices.

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- The very nature of fixed-price, fixed-schedule, full-wraparound performance-guarantee EPC contracts has likely been a main reason for issues experienced at existing CSP plants. Given the nascent state of the technology and the market, some EPCs did not have adequate knowledge to properly bid, engineer, procure, construct, and commission projects. As a result, many EPCs and projects have struggled with cost, schedule, and performance. The most successful projects have experienced owner and EPC contractor teams.

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Major Findings

The SolarPACES concentrating solar power (CSP) project database[1] was used to identify the current CSP projects that are in commercial operation around the world. As of the end of 2018, 94 commercial CSP trough and tower projects had achieved commercial online operation, with all but 4 still in operation active (76 operating parabolic trough plants and 14 operating tower projects). For this study, we received input from participants representing more than 80% of these projects.

It is important to note that the survey process was more qualitative than quantitative, largely due to concerns of confidentiality of information. Participants were invited to respond to a series of general questions and allowed to focus on the topics of most interest. We acknowledge that the results are biased by the topics of interest of the participants and the project team. However, we did receive quantitative results from several participants indicating where the shortfalls in performance occurred in plants. The results were very consistent with the findings in this report.

Early in the interview process, it became clear that project implementation issues were viewed as the cause of many of the most significant problems at operating plants. We have attempted to capture those issues and dedicate a significant portion of the report to them, in addition to the technology-specific issues identified in the surveys.

Using the large amount of data that was gathered in this study, we developed a database to track the various technology, operational, and implementation issues identified by participants. The database helps capture and classify the issues and identify potential risk and impact to future projects. The approach is subjective but useful.

Summary of Results

Over the course of the project, 1,008 issues were entered into the database: 272 technology issues for parabolic trough technology, 204 technology issues for tower technology, and 532 project-related issues that relate to troughs, towers, or are technology-agnostic. Table 1 provides a summary of the issues by technology and major systems or categories of issues.

[1] SolarPACES CSP Project Database, www.nrel.gov/csp/solarpaces

Table 1. High-Level Summary of Technology and Operational Issues in Operating CSP Plants

Technology Issues	**Parabolic Trough**		**Central Receiver**		**Common**		**Totals**	
Solar Field / Heliotat Field	51	19%	45	22%			96	20%
HTF System / Receiver System	107	39%	85	42%			192	40%
Thermal Energy Storage	28	10%	31	15%			59	12%
Powerblock	86	32%	43	21%			129	27%
	272		**204**				**476**	
Project Issues	**Parabolic Trough**		**Central Receiver**		**Common**		**Totals**	
Commissioning	0	0%	0	0%	69	14%	69	13%
Contracts	0	0%	0	0%	64	13%	64	12%
Development	0	0%	0	0%	25	5%	25	5%
Engineering	0	0%	2	11%	61	12%	63	12%
EPC	3	14%	6	33%	90	18%	99	19%
O&M	18	82%	9	50%	73	15%	100	19%
Performance	0	0%	0	0%	12	2%	12	2%
Procurement	0	0%	0	0%	11	2%	11	2%
QC	0	0%	0	0%	25	5%	25	5%
Structure	1	5%	1	6%	62	13%	64	12%
	22		**18**		**492**		**532**	
Total Technology + Project	**294**		**222**		**492**		**1008**	

Note: HTF = heat-transfer fluid; EPC = engineering, procurement, and construction; O&M = operations and maintenance; QC = quality control

Results of Interviews and Surveys

The following sections summarize many of the key findings in the report.

Parabolic Trough Power Plants

Parabolic trough power plants use large fields of parabolic trough solar collectors to collect thermal energy to produce steam to generate power in a conventional Rankine cycle steam power plant, or to store the energy in thermal energy storage (TES) for later use to generate power when the sun is not shining. Between 1984 and 2018, 80 parabolic trough plants ranging in size between 15 MW and 280 MW achieved commercial operation. Seven of these have reached the end of their original 30-year power purchase agreements (PPAs): four have been closed and decommissioned, but three have extended their operation beyond 30 years. Of the 76 plants operating, 31 include between 2.5 and 10 hours of TES. All new plants built since 2013 have included some amount of TES.

The general perception by the participants is that parabolic trough technology is mature, but improvement is needed in the performance and reliability of some systems and components. During the study, interviews with participants identified several areas where the technology still needs improvement. There is a general lack of standards for the solar technology used in plants as well as a lack of guidelines for designing the plants. To date, the annual performance of parabolic trough projects has been mixed. Some plants have performed exceptionally well from initial start-up, whereas others have experienced poor availability of key equipment. However, it is important to note that most plants appear to achieve high availability of the solar field, with

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most problems occurring in conventional equipment or systems such as heat exchangers, pumps, and valves. These issues are avoidable and typically occur due to improper design, construction, or operation of the equipment. The list below highlights some of the major issues and related best practices reported by participants for parabolic trough technology.

- Heat-transfer fluid (HTF) system – The design of the HTF system is critical to a well-functioning and performing parabolic trough plant. Deficiencies in the reliability and design of the HTF system still occur. One of the most significant issues is related to the ullage system design and ability to remove HTF degradation byproducts (high and low boilers) and water. Of recent concern, the inability to remove excessive hydrogen from the HTF system has become critical from a performance perspective. Hydrogen, generated during the breakdown of HTF, permeates into the vacuum space of the receiver and eventually will cause significant performance impacts. In recent years, there has been a growing understanding of the issue and approaches to address the issue. The design of the ullage system should be based on design process conditions and result in a system that removes and maintains levels of breakdown products and hydrogen such that performance of the receivers will not be impacted for the life of the project. As such, the HTF ullage system should be designed to maintain the parameters required by the receiver suppliers for the full operational period. We find that most plants include ullage systems, but it is not clear if they have been designed correctly, fully commissioned, or are operated correctly. With the current HTF, consideration needs to be given to designing plants to operate at lower maximum operating temperatures. New approaches are being developed to scrub hydrogen from the HTF. Receivers can also be injected with argon to disrupt heat losses caused by hydrogen in the vacuum and regain most of the original performance. New HTFs are being considered that could help alleviate the hydrogen issue and potentially improve the economics of parabolic trough technology.

- Other notable concerns by some participants with the HTF system were HTF pump seal reliability; HTF piping supports failures, and valve reliability. HTF pump seal reliability has improved over time, with recent issues appearing to be related to abnormal process conditions such as high water content and issues with the pump-seal cooling system (auxiliary equipment). Anticipated and potential abnormal process conditions should be well understood by the pump manufacturer; it is critical to select the correct pump, seal, and seal skid designs. Several plants noted problems with piping supports and damage, whereas others had none. A good HTF pipe stress study is required for the pipe configuration and support design. It should consider all the HTF piping, including power block, solar-field headers, and header-to-loop piping. HTF valve reliability pertaining to both internal and external leaks at some plants was noted as an issue, and in some cases, it has led to significant down time of equipment due to the inability to isolate. Quality valves designed for the rigorous cyclic and transient HTF conditions should be used.

- Collector interconnections – Issues have been reported on ball joints, flex hoses, and hybrid interconnections (rotary joints with flex hoses and other configurations), with some implementations of the hybrid configurations apparently being the most reliable. Ball joints leak, induce stress on the receiver (may require more substantial collector supports), and require significant labor to maintain. Flex hoses have the potential to catastrophically rupture and have a considerable pressure drop compared to ball joints,

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but some original flex hoses at the SEGS plants are still in service. Hybrid units have been reported with no mechanical issues when properly installed and no significant HTF leakage.

- Collector technology – Parabolic trough collector technology has matured in recent years. There has been much learning over the last 15 years. However, there is still a lack of industry standards for collectors. The key need is for standards to design collectors to survive wind loads. Not all collectors are designed with the same methodology, and as a result, they have different design criteria and different wind survival capabilities. Additionally, several plants have been built in locations where it appears that the actual wind conditions may have been worse than the design criteria. There have been a few notable collector failures due to windy conditions, and these have occurred to collectors designed by some of the more experienced collector providers. The industry needs better design standards and practices for defining the design wind conditions at a site. Although significant advances in collector optical qualification have occurred in recent years, most plants still do not appear to have a good understanding of the actual optical performance of their solar fields. This is an area where new projects could benefit from the new tools starting to be available.

- Thermal energy storage – Limited information has been shared on the technology. There have been some specific issues with particular types of HTF-to-salt heat exchangers. The process designs need to accommodate the daily temperature cycling and stay within the temperature gradients of the equipment. Lack of adequate quality control of the welding during the manufacture of heat exchangers has also been raised as an issue by participants. There have been issues with valves, heat tracing, and instrumentation (particularly flow meters). But long-shafted salt pumps in the storage tanks appear to be working well. Using low-chloride-content salts has helped keep corrosion rates at acceptable levels. Plants need to be designed to accommodate HTF leaking into the salt piping and storage system because this appears to be a relatively common but typically manageable problem.

- Steam turbine – Turbine reliability has generally been good, although in recent years issues related to back-end turbine blading has become a concern. Several projects have had to make modifications to the turbines, but these modifications have been reported to have satisfactorily addressed the issues. Turbine start-up efficiency should receive greater attention for CSP-specific operation. Turbine ramp-up and start-up curves are not always optimized with the manufacturer and should be discussed and determined early in the project. Valves for turbine bypasses should be placed close to turbine, and short piping runs from the steam generation system (SGS) should be considered to speed up system heating times. It has also been reported that some turbines can start up with only the low-pressure turbine, an approach that appears to improve start-up time.

- Control system – Full functionality of the control system has been reported by many to be lacking during and after commissioning and often well into the operations and maintenance (O&M) phase. Issues have been reported from poor alarm management such that there are too many alarms, which thus become “nuisance” alarms that are ignored. Combined with poor logic and lack of warnings, these could lead to exceeding

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manufacture operating recommendations on equipment. Automation functions are generally not implemented well. HTF flow control and steam generator level control are examples of two systems where automation should be of higher priority. Adequate time for tuning of the distributed control system (DCS) should be considered because this will extend beyond the commissioning period in order to capture the plant's different start/stops and transient behaviors.

Molten-Salt Tower/Central Receiver Power Plants

Central receiver power plants use a field of large mirrors (heliostats) that track the sun. The reflected energy is focused on a heat exchanger located at the top of a tower. The receivers in current operation are water/steam boilers (PS-10/20, Ivanpah, Khi Solar, and Ashalim) or nitrate salt heat exchangers (Gemasolar, Crescent Dunes, Noor Ouarzazate III, Delingha, and Dunhuang). Plants with salt receivers offer thermal storage capacities in the range of 6 to 16 hours of full-load turbine operation. Several large projects in development (China, Chile, and Dubai) are based on the molten-salt tower configuration.

Central receiver technology is at an earlier state of commercial maturity given that fewer plants have been built and they are a mix of technologies. To date, the performance of a number of these early central receiver projects has been below design levels. The reasons are varied, with some commonality among the projects. The experience and knowledge gained in current projects are expected to contribute significantly to better engineering practices in future central receiver plants. Most of these problems are solvable by straightforward design and operation changes. Given the early stage of development for tower technology, it is recommended that sponsors of new projects prepare and maintain an owner's technical specification (OTS) that captures the experience from previous projects and imposes minimum technical requirements on the engineering, procurement, and construction (EPC) contractor. Some of the key issues at current projects include:

- Leaks in hot-salt tanks – Leaks have occurred in the floors of hot-salt tanks at two operating plants. The cause has been reported as due to construction errors. However, there is also some concern about friction forces between the tank floor and the foundations. Repairing the tanks has required delays that have significantly degraded plant availabilities. In addition, salt that leaks into the foundation can introduce increased thermal losses, cause overheating of the foundation, and produce NO_x. It is recommended that sufficient attention be given to the design and construction of salt tanks and tank foundations. Tank specifications should accommodate all potential combinations of cyclic temperature and cyclic salt levels. Special attention should be given to the quality assurance (QA)/quality control (QC) of the tank construction and welding. Design features should be implemented to prevent salt from leaking into the tank foundation. There is no design code for molten-salt tanks. The American Petroleum Institute (API) Standard 650 is limited to 2.5 psi and 200°F and is the closest design code for these tanks. The industry should develop a design standard for hot- and cold-salt tanks.

- Differences between actual and expected site radiation – Future plant-performance models must capture the effects of short-term clouds, jet contrails, and conservative operator responses to windy days.

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- Attenuation – Accurate measurement of atmospheric attenuation is an issue at many potential and existing central receiver project sites.

- Differences between actual and expected flux distributions on the receiver – Heliostats in some commercial plants have exhibited higher slope and pointing errors than receiver specifications due to issues with facet canting, changes in the module focal lengths from solar heating, and position encoder errors. The consequences are spillage losses higher than projected and reductions in receiver tube lifetimes. New projects should verify that designs meet required receiver specifications and validate heliostat fabrication and installation methods that ensure optical performance. There are no performance or design code standards for heliostat/receiver design and integration of heliostats. The industry should develop a design standard for this.

- Heat-trace capacity and insulation quality – Insufficient heat-trace capacity, in conjunction with defects in the thermal insulation produced by cyclic operation, has led to salt freezing in both pipes and the receiver. Recovery times can range from hours to days. Future projects should provide a robust heat-trace system. Significant attention to heat-trace and insulation installation is essential. Control of the heat trace should be integrated into the DCS, and active monitoring of heat-tracing circuits should be automated to enable rapid identification of problem areas.

Steam Generation System

The reliability of the SGS has been the most noted issue regarding availability at both trough and molten-salt tower plants. There have been some issues with heat exchangers having manufacturing defects, specifically on the tube to tubesheet welding. Additionally, some heat exchangers have had issues due to process design issues, most notably being subjected to excessive temperature gradients during operation. Finally, some have had issues due to being subjected to improper water quality during operation. It is worth noting that the SGSs were not significant issues at the SEGS plants that operated for 30 years.

In commercial projects, whether parabolic trough or molten-salt tower, the steam generator typically consists of a superheater, reheater, evaporator, steam drum, and economizer. In some projects, the evaporator and steam drum are replaced with a kettle evaporator. For designs with a steam drum, the evaporator can use either natural or forced circulation. In the majority of commercial projects, the heat exchangers are shell-and-tube designs. To accommodate cyclic operation, the tubes are typically seal-welded to the tubesheets and then plastically deformed into the tubesheets. In the balance of the commercial projects, the heat exchangers are header-coil designs. The flat tubesheets are replaced with sections of pipe. Holes are drilled in the pipe, nozzles are welded to the pipe, and the tubes are then welded to the nozzles.

The vendor will specify operating limits, such as rate of temperature change, number of thermal cycles, thermal shock (difference between the metal temperature and either fluid temperature), and number of thermal shocks.

The availability of steam generators in trough projects has generally been good, but availability values have, in some projects, been below the design level. The steam generators are connected directly to the collector field. During morning start-up and afternoon shut-down, the temperature

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of the HTF leaving the field can be controlled such that the heat-exchanger rates of temperature change are within vendor limits. However, a number of participants have reported failures related to temperature gradients during transients experienced in starts, ramping, and stops (including turbine trips). Leakage between the tubes and tubesheets has also been reported due to inadequate control over the quality of the tube rolling/welding operations. The shell-and-tube materials (carbon steel) are generally exempt from many of the corrosion mechanisms that can affect stainless-steel heat exchangers in salt-tower projects. However, inadequate control of the water chemistry can result in flow-accelerated corrosion of the tubes.

In contrast, the availability of steam generators in tower projects has been mediocre. Steam-generator operation is started by blending hot salt with cold salt, and inadequate control over the blending process has led to rates of temperature change and a number of thermal cycles that are well in excess of vendor limits. The transient conditions have relaxed the friction connections between the tubes and tubesheets, which has led to numerous leaks, even on seal-welded tubes. Also, inadequate control over the water chemistry has led to the deposition of iron compounds in the stainless-steel tubes of the evaporator. This, in turn, has produced local pitting corrosion and consequent leaks.

To reach the availability targets for the steam generators, the EPC must specify heat exchangers that are as robust as possible and provide the equipment necessary to provide accurate control over gradients and transient conditions. This equipment can include items such as split-range control valves, preheating of feedwater using live steam, and a means to protect equipment in case of turbine trips. The O&M staff must also maintain strict control over the water chemistry.

Engineering, Procurement, and Construction

The EPC contractor is responsible for delivering a CSP plant that meets the OTS and that meets the guaranteed performance level. Standard ASME (American Society of Mechanical Engineers) and other engineering codes should be fully applied by the EPC to meet all appropriate requirements. The EPC should design the plant to meet the business case of the owner; that is, to balance the plant capital cost and its reliable operation with the required revenue generation. However, it is normal for the execution model and strategy of the EPC to focus mostly on cost and schedule and less on the quality and operability of the completed plant. The related best practice is for the EPC, based on the OTS, to develop adequate and complete functional specifications and process engineering so that the plant can be operated within vendor requirements during transients, start-up, and shut-down, and to pay attention to and manage the many interfaces between the technology providers.

The contract between the EPC and the owner is of crucial importance to the success of a CSP plant. Related best practices include (1) the involvement of the owner's engineer (OE) and/or the owner's technical experts familiar with CSP plants when developing an appropriately detailed OTS and negotiating the EPC contract, (2) implementation of a strong project management plan with effective oversight and communication, and (3) motivation of the EPC and the owner to fix problems as they occur through implementing a process for timely resolution of issues. The EPC contract should include clearly defined completion milestones that focus on quality and completion of key project elements. EPC payments should be structured on completion progress. It is difficult to find optimum solutions to problems once the project has started, so the EPC

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contract should include the cost and schedule for important preliminary design studies. The owner needs to establish effective communications and provide dedicated staff to support this.

Important issues related to engineering pertain to timing, design reviews, and the need to design for operational transients. Because inadequate design/engineering can result in problems all the way through the project and into operation, the project should establish and manage a thorough and disciplined top-down engineering review at various stages during design with the authority to resolve the identified issues. In addition to the daily start-up and shut-down cycles, the EPC must also maintain rate of temperature change within equipment limits by understanding and designing for transitions between operational states caused by changes in the weather, equipment failure, or dispatch requirements that may occur during the operating day.

Issues can arise in the procurement phase because it is common for the EPC to break the system into components and subsystems and bid them out separately to get the lowest acceptable price. It is more difficult to manage the integration of components that must work as a system when the components are procured independently. A best practice would be to create comprehensive contracts that define the responsibilities and interrelationships between the EPC and technology providers, provide detailed interface, acceptance criteria, redundancy and critical performance requirements, and engage engineers to add the needed specificity. Because CSP plants are often built in remote locations, problems in getting equipment and skilled people to remote sites can be diminished by adequate logistical planning as well as completing a survey of the local critical skills and suppliers needed for construction and operation of the plant before notice to proceed (NTP).

The success of a CSP plant is evidenced by how well its performance supports the financial model. It is therefore critically important that the plant's financial targets are met by minimizing schedule and cost overruns. A related best practice is for the EPC to perform thorough planning and engineering and use of the completion of engineering milestones as EPC payment triggers.

The EPC contract should include third-party optical and mechanical evaluation of the solar field at early and clearly defined points in the solar-field assembly and installation, and at commissioning.

Quality Assurance/Quality Control

QA and QC are intertwined in a successful application. In essence, QA establishes the methods to be used to assure high quality in the planning and execution of an undertaking (such as developing a CSP plants in all its steps). QC, on the other hand, establishes the methods and entities to implement the QA objectives through measurement and testing. The owner, OE, and EPC involved in implementing a project should be involved in defining the details of the QA procedures, and the QC teams should carry out the steps required to achieve comprehensive testing of equipment and systems.

The importance of well-executed QA/QC in all phases of the development, design, procurement, construction, commissioning, and operation of a CSP power plant cannot be overstated. Proper attention to QA/QC from the onset of project development will help reduce future costs, decrease unavailability, and increase performance. QA/QC oversight by the owner, EPC management, and O&M supervision must be carried out at several levels as a project develops. Thus, the OE

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contract, EPC contract, and O&M contract must be detailed and explicit in defining the roles of those entities. The owner (via the OE or its equivalent) and EPC carry the main QC roles in these activities.

- The owner and the EPC must engage enough experienced staff to carry out the QC needs in all aspects of the plant development and operation. Properly done, this can be an extensive requirement given the needs during EPC and turnover to O&M.

- The independent engineer (IE) and OE have a critical role to play in the QA/QC process. Some of the key issues experienced at CSP projects can be traced to a lack of adequate involvement of IE/OEs.

- All key components should be tested either in the fabrication line at the supplier's shop and prove proper testing documentation, or in a clearly defined incoming inspection at the power-plant site.

- Project standards should include well-prepared QC documents covering methodologies and acceptance criteria for equipment, systems, and interfaces. Interface and QA/QC documents need to be understood by all parties.

Commissioning

Project commissioning is the operational step after EPC, but it will usually start before construction is completed. The main goal of commissioning is to accomplish the safe and orderly handover of the plant by the EPC to the owner for normal operation by the O&M team, guaranteeing its operability in terms of performance, reliability, safety, and data traceability.

The commissioning process is the integrated application of a set of engineering techniques and procedures to check, inspect, and test every operational component of the project—from individual functions such as instruments and equipment, up to more complex entities such as subsystems and systems. Importantly, this includes operation of all plant systems, subsystems, and equipment over as full a range of operating conditions as possible.

The overriding goal in this process is to ensure that all components and systems of the power plant were selected, designed, engineered, installed, tested, operated, and maintained for the detailed plant engineering configuration to satisfy all plant operational requirements.

Commissioning of the plant is concluded with a series of tests to demonstrate the operability and efficiency of the various systems. Initial acceptance occurs at the successful completion of these tests. After initial acceptance, the care and custody of the plant is typically turned over to the O&M team for operation. Initial acceptance is related to the EPC contract. This is often also the same or very close to the commercial operation date (COD), which relates to the start of commercial operation per the PPA contract.

Key elements of the commissioning process include:

- Independent oversight of the QA/QC carried out by the EPC during commissioning is expected to be assigned by the owner to the OE or other designated qualified entity. This

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oversight entails considerable engineering activities, because it requires assurance that the final plant design, including all equipment and systems, can achieve the goals of the power plant. For example, it should include review of the commissioning plan, detailed inspections of construction and testing, performance oversight, and approval sign-off of all completed systems prior to owner acceptance. This supplements the QA/QC by the EPC itself.

- Although the commissioning is an EPC responsibility carried out by a team under the EPC, it is advised by many participants that key members of the engineering and O&M teams should be included on the team for purposes of experience, knowledge, advice, training, and familiarity with all facets of plant operation.

- Extensive and thorough QA and QC are very important in commissioning, during which all systems are tested and operated for proper design, construction, and performance prior to turnover to O&M. Proper QC is necessary to both observe whether a system and its interfaces are correct and to ensure that no damage is inflicted to plant components and systems during the commissioning process and/or by inappropriate operation of the plant.

- Steam-blow cleaning of the steam piping is a critical part of the commissioning of the power plant. It is important that the plant be designed from the start to address the temporary piping spool pieces that will be required during commissioning. The plant should consider how it will get the steam from temporary heaters. It may not be possible to use the solar SGS to generate the steam required for the steam blows.

- Review supplier/factory tests carried out by the EPC during the procurement activity.

- Check the functioning and accuracy of instrumentation and other measurement devices.

- Perform thorough checks on the functioning of the DCS and other major plant control systems.

- Conduct functional performance and initial reliability tests of all plant subsystems and systems.

- Confirm adherence in commissioning tests to all operational and maintenance standards and other requirements for equipment, such as the steam turbine, thermal storage, key pumps, and key heat exchangers.

- Operate the full plant in all appropriate stages, adhering to required limits on such operations as ramping speed at start-up and shut-down.

Operation and Maintenance

The O&M contractor, commonly referred to as the operator, can be an affiliate of the owner, an affiliate of the EPC, or a third-party company. There is good experience with any approach, but it is critical that the operator is an experienced and capable company, ideally with appropriate CSP O&M experience and expertise. The key is for the O&M staff to be completely trained and

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O&M company and systems fully mobilized when it is time for the operator to take over control of the plant.

Many participants identified areas where it is advantageous to have the O&M team support the project prior to the operational phase.

- Design Phase – O&M expertise and involvement during the design phase for review and validation of: adequate process control for temperature gradients and protecting equipment associated with transients, start-ups, and trips; measures to incorporate efficient/fast start-ups including piping designs and manufacturer's start-up curves and assumptions; equipment location and measures for safe and rapid evacuation of process fluids for maintenance purposes; and the water chemistry program, along with the design/plan for long-term water chemistry needs.

- Construction Phase – O&M representation should be brought into the project during construction to learn and become familiar with the plant equipment. This knowledge is helpful through commissioning and the O&M phases. O&M representation should also work with the owner's QC/OE team. These subject-matter experts can monitor O&M-related issues that came up during the design stage/review. They should also continuously seek out items that would hinder plant operations, equipment access / isolation / maintenance, and safety / environmental concerns.

- Commissioning Phase – Involvement of the O&M team is important during commissioning to ensure that the O&M staff is well prepared for the turnover point in the project when they become responsible. Lack of O&M input and participation in this phase has led to inadequate staff training and familiarization, deficiencies in control systems, and incomplete O&M procedures. O&M involvement with the QA/QC of the control system and O&M procedures can help ensure proper plant operations and avoid exceeding equipment limitations during the operating phase. O&M staff presence during this time can allow the O&M staff to work on turning the EPC-provided O&M manuals and documentation into proper O&M procedures, which EPCs often fail to provide.

Participants have indicated that many times the O&M contractor has not been fully prepared to take over the operation of the plant at initial acceptance. That is, it did not appear that projects fully budget and plan for the O&M contractor to fully mobilize and be ready at initial acceptance. It is important that the mobilization of the operator be fully planned out and integrated into the overall project schedule and budget. Although many projects require the EPC to provide training for the O&M company, it has also been noted that a better practice would be to have the O&M company responsible for training, preparation of operating procedures, and full mobilization of the O&M team and processes. The O&M contractor can work with the EPC contractor to manage the equipment and process specific training required for the O&M team.

Many project participants have indicated that O&M costs during normal operation were generally higher than anticipated or budgeted at financial closing. There tend to be issues that are not fully considered, and it generally falls to the owner to pick up the additional costs. Some of these issues are related to obtaining and keeping quality O&M staff; lack of understanding of regional cultures; and availability and timeliness of spare parts and services. It was also noted

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that, in many cases, O&M costs increased over time as the degradation of certain components increased at a rate not considered in the O&M cost estimate. It is also important to budget increased cost for O&M during the early years of the project—maybe 3 to 5 years, depending on the maturity of the technology and company—until full learning and tuning of the plant is achieved. Experienced O&M contractors typically know how to staff and budget the O&M of a CSP plant; most inexperienced owners and operators do not. The O&M budget should be reviewed after the final design of the plant is completed and again at initial acceptance to make sure the plant, as designed and constructed, is in alignment with the O&M assumptions.

Solar Resource Measurement and Performance Modeling

Solar resource assessment is very important to project development because CSP plants are usually large investments, and the estimation of the direct normal insolation (DNI) solar resource is one of the biggest sources of uncertainty related to power yield. There have been notable cases where the initial DNI estimates for a project site have been significantly different than the actual data measured at the site after a plant has been built. This is both in terms of the total annual resource at the site, the seasonal resource distribution, and the potential for intra-hourly resource transient behavior.

- Many projects have made their annual performance forecasts based on hourly DNI data. This has been a holdover from earlier typical meteorological year (TMY) and satellite DNI availability and typically does not accurately account for the transient behavior of the plant, especially for short-term cloud transients. It is best if currently improved DNI data are used, in which time resolutions of 5, 10, or 15 minutes can be provided. For central receiver plants, potentially 1-minute data are desired to better understand the implications on receiver operation.

- For tower plants, better measurement of atmospheric attenuation is needed during project development. Better industry-approved instruments and/or techniques are needed for estimating attenuation prior to installation of the plant. Potentially, separate approaches should be used during development and during operation of the plant.

- The costs for detailed solar and meteorological assessments of a site are very small compared to potential impact on performance. It is currently the practice in CSP development that the developer(s) select a qualified firm to provide a TMY recommendation with sufficient backup of its reliability. Data on inter-annual fluctuations should be part of the assessment.

- All CSP projects rely on a performance model to determine the expected performance for calculating the performance guarantee. The industry needs independently validated performance models that can be used for performance guarantees and for evaluating the operational performance of the plant. These models need to be able to accurately model daily start-ups, shut-downs, and cloud transients.

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1 Introduction

1.1 Background

In 2017, the U.S. Department of Energy (DOE) Solar Energy Technologies Office (SETO) released its 2018–2022 Multi-Year Program Plan. The plan delivered insights, goals, and objectives for pathways pursued by SETO, including concentrating solar power (CSP), to "spark innovation and enable technology combinations that advance the widespread adoption of solar power."

Within the Multi-Year Program Plan, the SETO program described its desire to minimize operations and maintenance (O&M) costs through developing improved procedures by applying lessons learned from currently deployed power tower and parabolic trough CSP systems. With nearly a hundred CSP plants operating globally with a combined capacity of just over 5 gigawatts, an opportunity exists to understand experiences, best practices, and lessons learned about how these plants were designed, financed, built, and commissioned, and how they are now being operated.

Early in 2018, SETO issued a National Laboratory Call for Proposals to put in place laboratory funding to support core capabilities at national laboratories as well as to competitively select projects that responded to objectives set forth in the Multi-Year Program Plan described above. The National Renewable Energy Laboratory (NREL), working with Solar Dynamics LLC, proposed a single-year project titled "CSP Plant Construction, Start-Up, and O&M Best Practices Study." The proposal was selected for funding by SETO, with an NREL and Solar Dynamics team initiating work at the beginning in FY19. The stated objective of the proposed work was to develop a final report describing "best practices and lessons learned gleaned from the construction, commissioning, start-up, operations, and maintenance of existing CSP parabolic trough and power tower systems."

In addition to SETO funding, additional cost-shared support was solicited and granted from the International Energy Agency (IEA) SolarPACES and the World Bank to support data collection efforts during the course of the one-year project, and additionally, to support dissemination of best practices and lessons learned following publication of this final report.

1.2 Purpose

The capital cost of CSP systems continues to decline worldwide (see Figure 1-1). Anticipating continued cost reduction, future O&M will likely represent a growing percentage of CSP costs. As such, publication of best practices for design, construction, start-up, and O&M are critical to both continued near-term deployment of CSP technologies and long-term reduction in levelized cost of electricity (LCOE).

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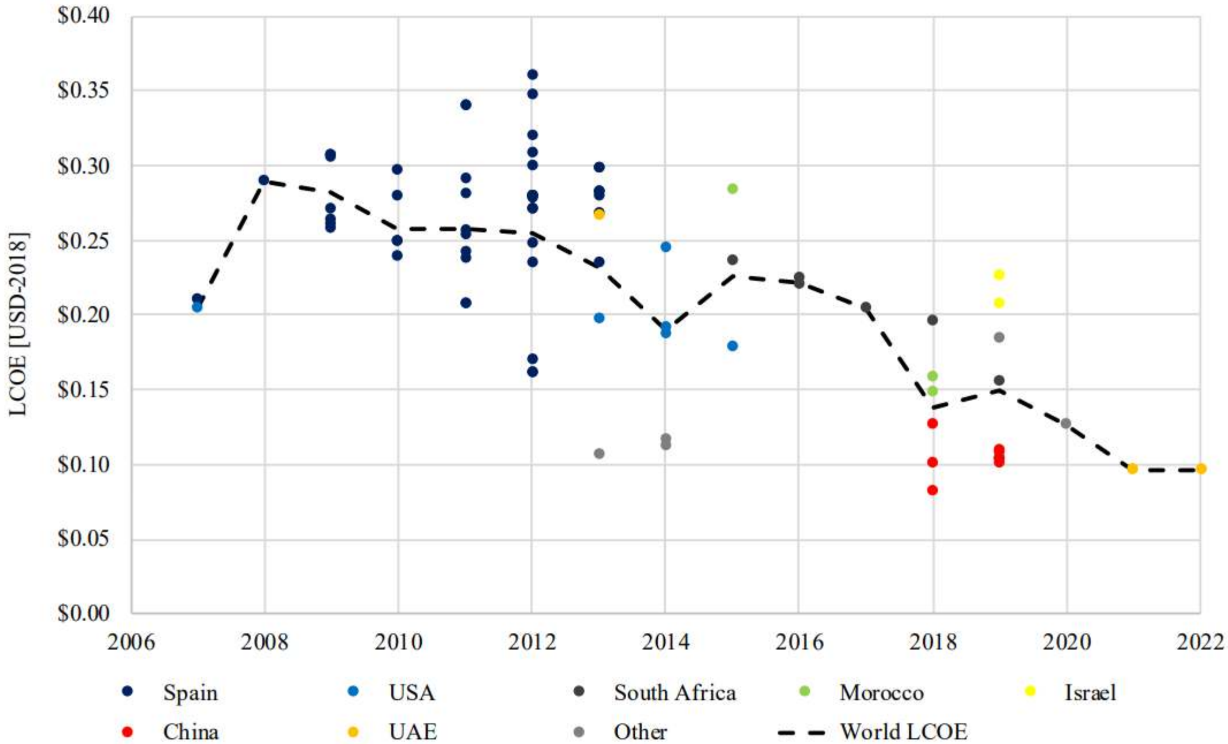

Figure 1-1. Levelized cost of electricity (LCOE) of the 77 solar-only commercial CSP stations for which csp.guru has data on both cost and expected generation for 2006–2018 (operational) and 2019–2022 (under construction in January 2019, scheduled completion 2019–2022). The average LCOE is the generation weighted average of all stations (expected) to start operating in each year.

As capital costs continue to decline, the annualized performance of CSP systems with established markets has improved over time. This is especially the case in Spain, where 45 parabolic trough systems were built due to attractive policies supporting CSP construction. The earliest parabolic trough plants began operation in 2009, allowing operators to accumulate more than a decade of operational experience to date. Best practices have been shared widely among the Spanish operator community, resulting, in part, in improved performance of Spanish plants as operators gain experience (see Figure 1-2).

It is important to note that the primary focus of this present project has been to identify best practices designed to rectify problems that have occurred at today's operating plants. Some best practices were likely not raised by the parties interviewed in cases where more routine problems have already been solved. Therefore, we expect to have missed improved practices that the CSP industry has already adopted to avoid past problems.

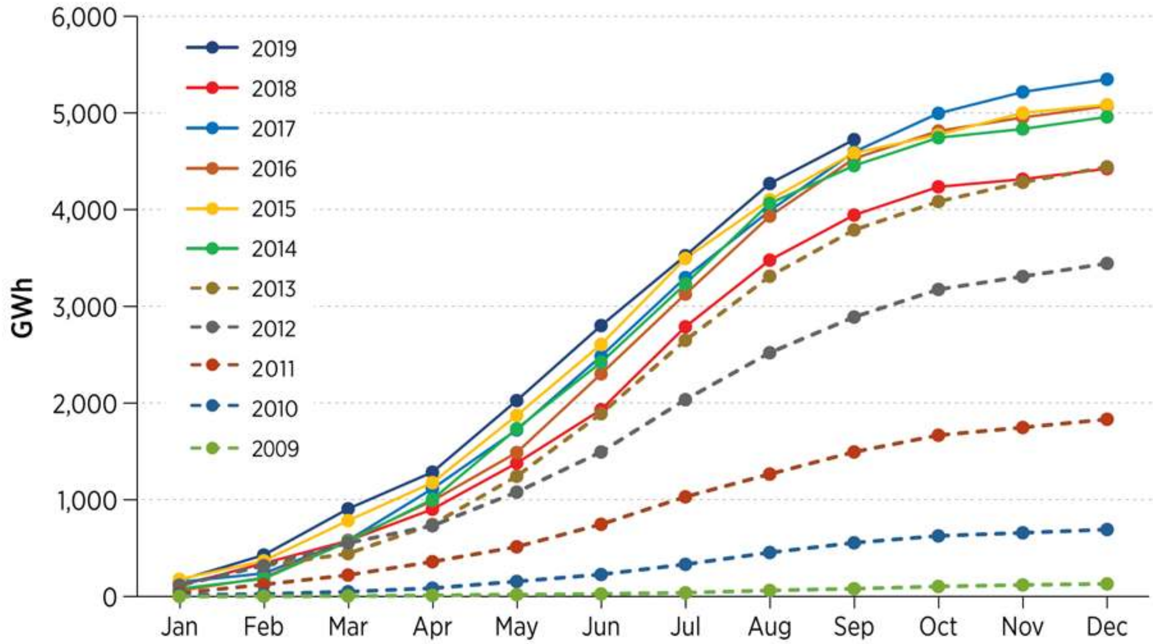

Figure 1-2. Monthly cumulative generation of Spanish CSP plants (Protermosolar). Dashed lines represent continued construction of CSP plants. Solid lines represent increased output from plants considering no additional construction. Reduced performance in 2018 is due to a significant reduction in direct normal insolation in Spain that year (Protermosolar).[2]

Although CSP systems have generally demonstrated reductions in cost and increases in performance, an overriding goal of this project is to ensure that a representative range of CSP experiences for both parabolic trough and central receiver plants worldwide include systems and components that have exhibited both good reliability as well as those that have suffered setbacks. By sharing both the positive and negative experiences—associated with the past and present design, construction, commissioning, and operation of CSP parabolic trough and central receiver systems—we hope that this report will prove useful to existing and future participants involved in the various phases of CSP deployment.

1.3 Approach

We divided the work performed under this effort into three primary tasks: (1) identifying, contacting, and securing participation from existing parabolic trough and central receiver developers, owners, EPC contractors, operators, and other entities representing the majority of operational CSP projects worldwide, (2) researching, collecting, and analyzing accessible lessons learned from these participating participants, and (3) publishing the best practices and lessons learned from these participants.

The SolarPACES CSP project database[3] was used to identify the current CSP projects that are in commercial operation. Currently, 94 parabolic trough and central receiver projects are listed in the database, with 90 in operation. Of these, we identified 76 operating parabolic trough plants

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[2] Protermosolar, https://www.protermosolar.com/la-energia-termosolar/el-sector-en-cifras/.
[3] http://www.nrel.gov/csp/solarpaces/

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and 14 operating central receiver projects. Over the course of the project, the project team held about 50 information-gathering sessions, collecting information from participants representing nearly two-thirds of the CSP plants operating worldwide (Table 1-1). A list of these projects is included in Appendix A.

Table 1-1. CSP Participants in this Project

Aalborg	DLR	Parsons Corporation
Abengoa	Fichtner	Sargent & Lundy
ACWA	Flowserve	SBP
Advisian/Worley Parsons	FTI	SENER
Atlantica Yield	Huiyin Group	SolarReserve
BrightSource	Lointek	SolEngCo
Cerro Dominador	Masen	SUNCAN
ChemTreat	Mott MacDonald	Terra-Gen (SEGS VIII/IX)
CMI	Nevada Solar One	TSK
Cobra	NRG	Vast Solar
CSP Services	OCA Global	Virtual Mechanics
DEWA		

Some of the information-gathering sessions were conducted during project team visits to operating CSP projects with O&M organizations or project ownership teams (Table 1-2).

Table 1-2. CSP Parabolic Trough and Central Receiver Plants Visited by Project Team

Parabolic Trough Plants	Central Receiver Plants
La Africana	Cerro Dominador
Mojave (Alpha and Beta)	Crescent Dunes
Nevada Solar One	Gemasolar
Noor Ouarzazate I and II	Ivanpah (1, 2, and 3)
SEGS VIII and IX	Noor Ouarzazate III
Solana	

Many of the organizations we contacted required non-disclosure agreements between the sharing parties. However, most participants were comfortable sharing information on the condition of maintaining anonymity within the context of the final report. As such, to the extent possible, we have structured this report such that issues and best practices are described without associating them with a specific project or company.

Finally, although many issues presented throughout this project were technology, numerous implementation issues were raised that almost always resulted in technology issues that impacted plant performance. We also describe these non-technology issues in this report, and they are generally organized following the steps in project development, EPC execution, and operation of a CSP plant.

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A database was developed at the beginning of the project and was used to track the various technology and operational issues that have been identified by the team or participants. The database has been designed to track the following information.

- Technology – Parabolic trough, central receiver, or both
- System – Solar field, heat-transfer fluid (HTF) system, thermal energy storage (TES) system, power block, or project level
- Subsystem/Component – Further detailed breakdown within each system
- Issues (design, construction, commissioning, or operational concerns needing resolution)
    - Issue/Description – Brief description of identified issue
    - Impact – Brief description of the impact of the issue
    - Mitigation Measures – Description of potential solutions or best practices
    - Impact Score: 1 – low, 3 – medium, 5 – high
    - Risk Level: 1 – low, 3 – medium, 5 – high
    - Priority Score = Impact score × Risk level
    - Source of Information.

As a result, the database provides a unique compilation of many of the issues, solutions, and best practices for CSP technologies from the CSP industry and participant perspective. We should note that we talked to many participants and often received input from multiple parties on the same project. We attempted to capture different perspectives where possible. But there is a natural bias to highlight areas of most concern and minimize areas that are not seen as issues. In general, the database seems to be a reasonable reflection of where issues have been experienced.

1.4 Summary of Results

The following tables provide a summary of the issues captured through participant interviews and written responses from participants. We summarize the responses by technology and major systems in Table 1-3, which shows that the issues were largely split between technology and project implementation issues. We provide a much more detailed breakdown by subsystem in Table 1-4, which shows the issues in parabolic trough and central receiver plants. A breakdown by specific issues is shown in Appendix B.

Table 1-3. CSP Issues Captured in Database from Participant Interviews

Technology Issues	**Parabolic Trough**		**Central Receiver**		**Common**		**Totals**	
Solar Field / Heliotat Field	51	19%	45	22%			96	20%
HTF System / Receiver System	107	39%	85	42%			192	40%
Thermal Energy Storage	28	10%	31	15%			59	12%
Power Block	86	32%	43	21%			129	27%
	272		**204**				**476**	
Project Issues	**Parabolic Trough**		**Central Receiver**		**Common**		**Totals**	
Commissioning	0	0%	0	0%	69	14%	69	13%
Contracts	0	0%	0	0%	64	13%	64	12%
Development	0	0%	0	0%	25	5%	25	5%
Engineering	0	0%	2	11%	61	12%	63	12%
EPC	3	14%	6	33%	90	18%	99	19%
O&M	18	82%	9	50%	73	15%	100	19%
Performance	0	0%	0	0%	12	2%	12	2%
Procurement	0	0%	0	0%	11	2%	11	2%
QC	0	0%	0	0%	25	5%	25	5%
Structure	1	5%	1	6%	62	13%	64	12%
	22		**18**		**492**		**532**	
Total Technology + Project	**294**		**222**		**492**		**1008**	

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Table 1-4. CSP Issues Captured for Parabolic Trough and Central Receiver by System and Subsystem

Parabolic Trough		
System	**Subsystem**	**Issues**
Solar Field	Civil	5
	Control System	1
	Drives	1
	Elect &I&C	3
	Instr. & LOC	6
	Mirrors	3
	Receivers	19
	Structure	10
	System	3
HTF System	Aux. Htr	6
	Expansion sys	6
	Fluid	5
	HTF Pumps	13
	Instrumentation	5
	Interconnect	20
	Piping	31
	System	13
	Ullage	8
Thermal Storage	Oil-to-Salt HX	13
	Piping	5
	Salt Pumps	4
	Salt Tanks	6
Power Block	Aux. Syst	3
	Civil	1
	DCS	12
	Electrical	7
	HTF SGS	27
	Steam Cycle	8
	STG	28
		272

Central Receiver		
System	**Subsystem**	**Issues**
Heliostat Field	Civil	2
	Control	4
	Drives	5
	Enviro	1
	Heliostat Structure	1
	Mirrors/Facets	14
	Power/Wiring	3
	System	15
Receiver	Cold Salt Pump	1
	Control Systems	14
	Downcomer	14
	Outlet Vessel	4
	Receiver	13
	Salt piping	21
	System	8
	Tower	10
Thermal Storage	Hot Salt Pump	4
	Piping	1
	Salt	3
	Salt Tanks	23
Power Block	Aux. Syst	3
	DCS	8
	Electrical	1
	Salt SGS	23
	Steam Cycle	4
	STG	4
		204

To help identify which issues are most important, each issue entered in the database was given an impact score and a risk level. The impact score identified the potential impact of the issue to the project, how significant of an impact on plant performance, cost, or schedule. The impact score was ranked 1 (low) to 5 (high). The risk level was an indication of how likely the problem was to happen. A risk level of 1 meant that the problem was rarely experienced or may only be associated with a problem at a single plant. A risk level of 5 meant that it was a common problem or could affect many plants. The scores are multiplied together to create a Priority Score. Priority scores can range from 1 to 25 for each issue. Of course, the ranking is subjective, but it is an attempt to give some quantification to the importance of issues. The most significant issues were brought up by multiple participants. It is important to note that the number of "occurrences" does not correspond to the number of times some kind of incident or issue occurred at a plant, but rather, the number of times it was mentioned by people who often overlap in terms of representing a single plant. We assume that the number of occurrences that

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an issue is mentioned indicates how important stakeholders think an issue is. Figures 1-3 and 1-4 are plots of the issues for parabolic trough and central receiver technology, respectively. They show the priority score of an issue as a function of the number of occurrences. Issues in the upper-right quadrant are the most important for the technology, and those in the lower-left quadrant are the least important of the issues raised.

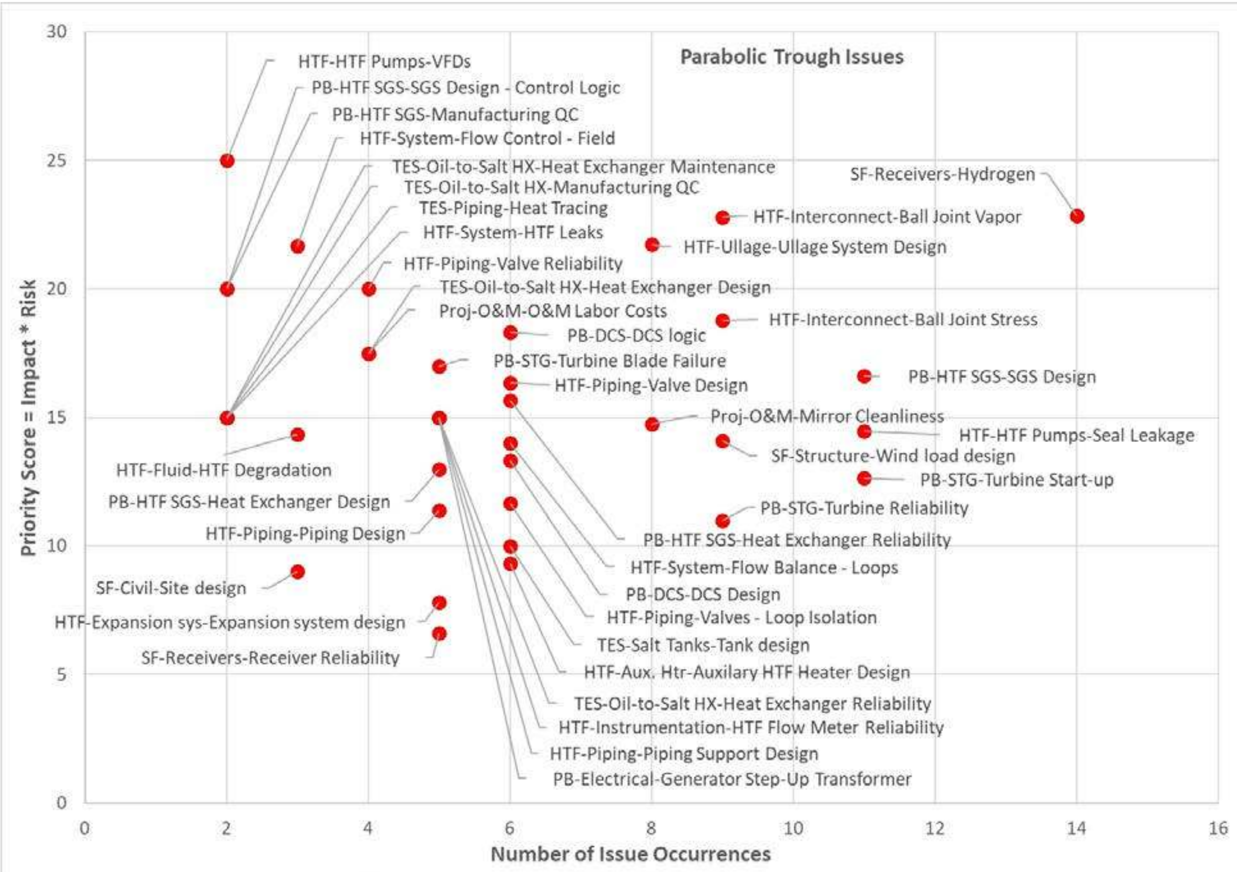

Figure 1-3. Parabolic trough issues plotted by priority score and number of occurrences.

For parabolic trough technology, the receiver hydrogen issue is clearly the issue that stands out the most. But ball-joint stress and leakage, ullage system design, SGS design and reliability, and HTF pump seal issues are in the next tier of concern. It is important to note that we believe all these issues have solutions or best practices to address them. Occurrences

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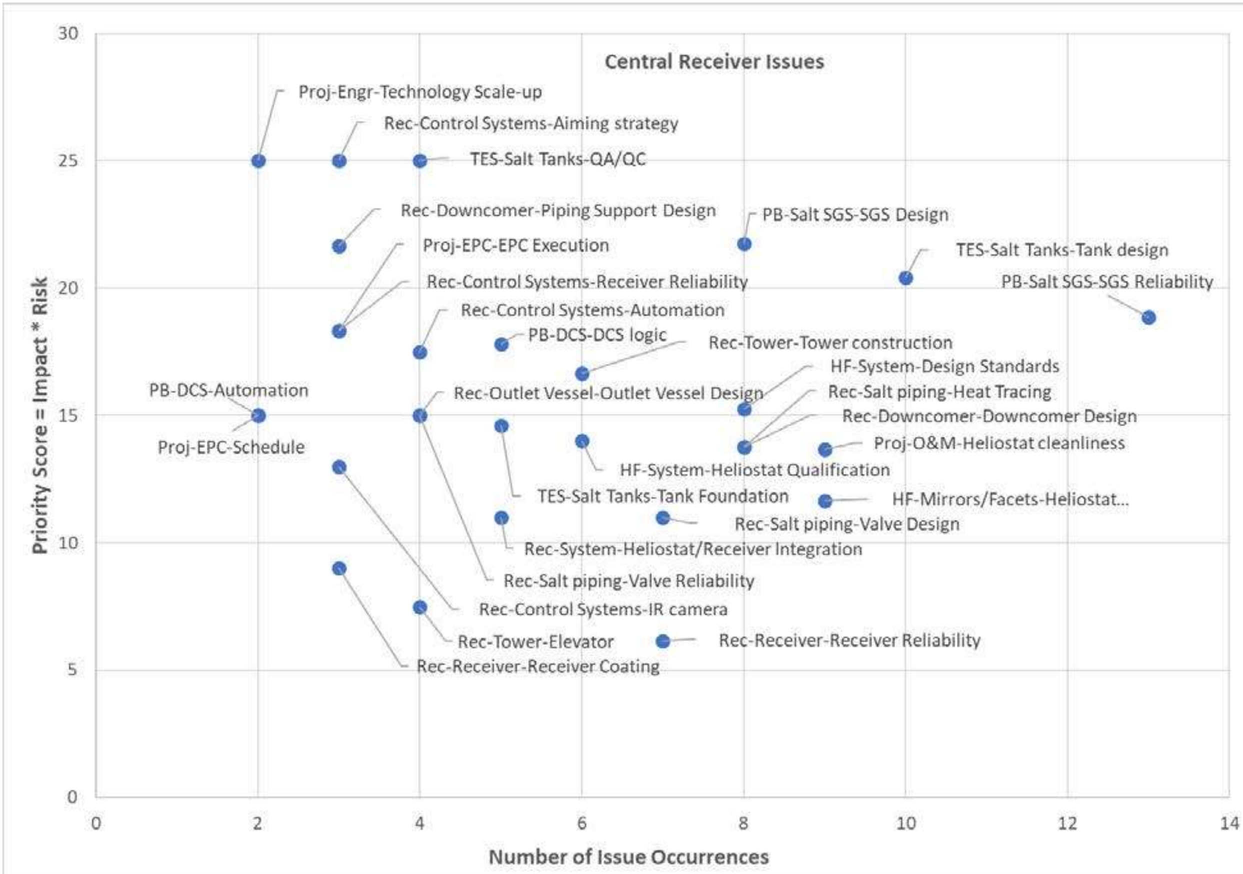

Figure 1-4. Central receiver issues plotted by priority score and number of occurrences.

For central receiver technology, the reliability and design of the SGS and the hot-tank design and foundation are the key issues identified. There is a large gap between these issues and the next set of issues, which indicates a significant reduction in risk and concern. Again, we believe that all the main issues have solutions or best practices to address them.

Similar charts have been developed for project development, project execution, and O&M. These are found in Appendix B at the end of the report. Appendix C provides a full tabular record of all issues, their occurrences, and priority scores.

The database holds a wealth of information on specific issues and best practices. We have attempted to capture the bulk of this information in the body of the report. The database itself contains some information that may be considered sensitive by project owners. The project team will continue to try to extract useful information from the database and make it available to the CSP industry and stakeholders.

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2 Project Organization and Implementation

During the interview process of CSP participants, it became apparent that the causes of many problems and issues experienced at CSP projects to date were not only due to the technology itself, but also, due to organizational and project implementation issues. To understand these types of issues, it is important to understand how CSP projects are structured and to understand the key roles of the various players. This section considers organizational issues, or the relationship between parties, and the development of CSP projects; the next section considers project execution, or the building of the project.

2.1 Project Development Overview

Public and investor-owned utilities have historically been the major sources of funding for new power-generation capacity, where the utility owns and operates facilities used for generation, transmission, and distribution of electricity to the general public. In this model, the utility contracts directly for new power-generation capacity to be built.

However, in recent years, utilities and governments have contracted new generation through independent power projects (IPPs), which allows access to private-sector financing of power generation. IPPs are defined as power projects that are mainly privately developed, constructed, operated, and owned; have a significant proportion of private finance; and have long-term power purchase agreements (PPAs) with a utility or another off-taker. Most CSP projects to date have been developed as IPP projects.

Although it is easy to think of a CSP project as the physical solar power plant, the project should be viewed in its wider context—as a financial investment and part of a complex financial transaction that allows the physical plant to be financed and constructed, with a view to it operating over a 25- to 30-year life. In some cases, projects are financed by public-sector debt, with the aid of development banks, or are financed off a company's balance sheet. But most CSP projects use a project finance structure. Project finance has emerged in recent years as the preferred approach for large-scale infrastructure projects, and it allows the use of private-sector debt. It also brings with it many requirements that shape the overall structure and relationships between parties of CSP projects.

For a CSP project to be built, there must first be an environment in place that supports the development of a project. An appropriate site is needed with adequate solar resources, topography, and infrastructure to support the construction and operation of the plant. A policy framework is needed that provides the commercial, legal, and governmental environment to support the development of IPPs. Finally, the appropriate financial framework is needed that provides long-term off-take agreements and other incentives that enable a CSP plant to be constructed economically.

2.1.1 CSP Historical Development

Several waves of CSP development have occurred when the appropriate environment was in place to allow CSP projects to be developed.

The first wave of CSP development occurred in the United States in California during the 1980s, when the Public Utility Regulatory Policies Act (PURPA) legislation allowed the framework for

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renewable IPPs, California created the Standard Offer contracts that provided 30-year energy and capacity PPAs, and Federal and State tax incentives helped buy down the cost of solar power plants. This enabled the development of the LUZ Solar Electric Generating Systems (SEGS). Nine parabolic trough plants were built between 1984 and 1991. Falling energy prices, delays in extension of incentives, and reduced incentives precluded further development. The SEGS development demonstrated the industrial nature of CSP technology and the need for stable energy policy to encourage continuous development and growth.

The second major CSP wave started with the introduction of the feed-in tariff (FIT) legislation for CSP projects in Spain in 2007 (Royal decree 661/2007). The FIT allowed 25-year off-take contracts with a high fixed tariff rate or a fixed adder on top of market time-of-delivery pricing. This enabled a major boom in CSP development, with about 50 plants bring constructed in Spain between 2007 and 2013. The Spanish government eliminated the FIT and no new projects were built. The FIT was fixed and did not encourage cost reduction or generation during preferred periods. However, the FIT demonstrated that rapid growth in deployment of CSP technology was possible when appropriate and stable policy is in place. The FIT also enabled a significant Spanish EPC and technology industrial capacity to develop.

The next major wave has been the international proliferation of CSP projects. These have generally been through competitive bidding processes. This includes significant developments in the United States, South Africa, Morocco, Israel, and the United Arab Emirates (UAE). Many of these projects have encouraged the use of thermal energy storage to allow solar generation to be dispatched to periods of highest need. Many of these use time-of-delivery rate structures to incentivize periods when power has the highest value. These projects have also demonstrated significant reductions in cost of power from CSP technology. These projects have been dominated by Spanish EPC and technology companies that entered the CSP market due to the Spanish FIT.

The latest wave in CSP projects has occurred in China. China followed the FIT approach and initially approved 20 demonstration projects of 50 MW or larger in phase I of the program. The Chinese program initially required projects to reach commercial operation within three years (by the end of 2017). This was extended, but only three projects had reached commercial operation by the end of 2018. It is not clear how many additional projects will be completed from these initial 20 projects and whether China will go forward with the second phase of the program, which would potentially support up to 5 GW of CSP. These examples illustrate that policy instability makes CSP deployment difficult due to the length of time required for CSP project development, financing, and construction.

There are several markets around the world that have indicated potential opportunity for the next wave of CSP projects, including China, Spain, the UAE, Saudi Arabia, Chile, and others. The value proposition for CSP in these markets is likely the ability to generate power during peak periods and/or at night with the use of thermal energy storage. However, CSP will need to compete on an economic basis against other technologies with storage. It is therefore critical that new CSP projects can be built on time, on budget, and perform as expected. The lessons learned and issues faced at existing projects documented in this report can help the next generation of projects.

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2.1.2 IPP Project Structures

IPPs invest in CSP technology and recover their cost from the sale of the electricity. They can be attractive financial structures in some countries, especially when the public sectors do not have the required financial capacity for investment. This is true for developing countries, but also has been an effective approach used in developed countries to encourage the expansion of renewable generation sources. Goals for integrating IPPs into the national energy mix can be summarized by the following three goals:

- Attract outside capital to meet rapidly growing electricity needs without imposing large strains on the nation's internal financial capabilities;
- Reduce electricity costs though competitive pressures; and
- Assign risks in a more efficient or desirable manner.

IPPs are tendered as build–own–operate (BOO), build–operate–transfer (BOT), or build–own–operate–transfer (BOOT).

BOO is a form of project financing wherein a private entity receives a concession from the private or public sector to finance, design, construct, own, and operate a facility stated in the concession contract. This enables the project proponent to recover its investment and its operating and maintenance expenses in the project. Unlike the BOOT or BOT structure, the private-sector party owns the project and does not have to transfer it to the government entity at the end of the term.

BOOT is a project delivery mechanism in which a government entity grants to a private-sector party the right to finance, design, construct, own, and operate a project for a specified number of years. For CSP projects, the transfer of the plant to the utility is usually scheduled after 20 years of operation. The operation should be long enough to cover debts, expenses, equity contribution, and an agreed profit through selling the generated power.

BOT is a project delivery mechanism in which a government entity grants to a private-sector party the right to construct a project according to agreed design specifications and to operate the project for a specified time. The private-sector party does not own the project. In exchange for assuming these obligations, the private-sector party receives payment from the government entity or the project's end users. In some cases, the private-sector party may provide some of the financing for the project. At the end of the contract period, operation of the project is transferred to the government entity.

In the rest of this document, we describe IPPs that are tendered as BOO. This is one of the most typical project structures used, but the others are often very similar.

2.1.3 Project Finance

Most CSP projects use a standard non-recourse project finance structure. *Non-recourse* means that the project can stand alone as a financial entity, and the project debt has no recourse to the project sponsor's balance sheet. The project is financed based on the value of the assets in the project company, the creditworthiness of its PPA, and the expected performance/cash flow of the

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project. One of the goals for project finance is that risk should be allocated to the participant most able to manage it. This approach typically allows the lowest overall risk premium, and therefore, the lowest cost or most attractive overall return.

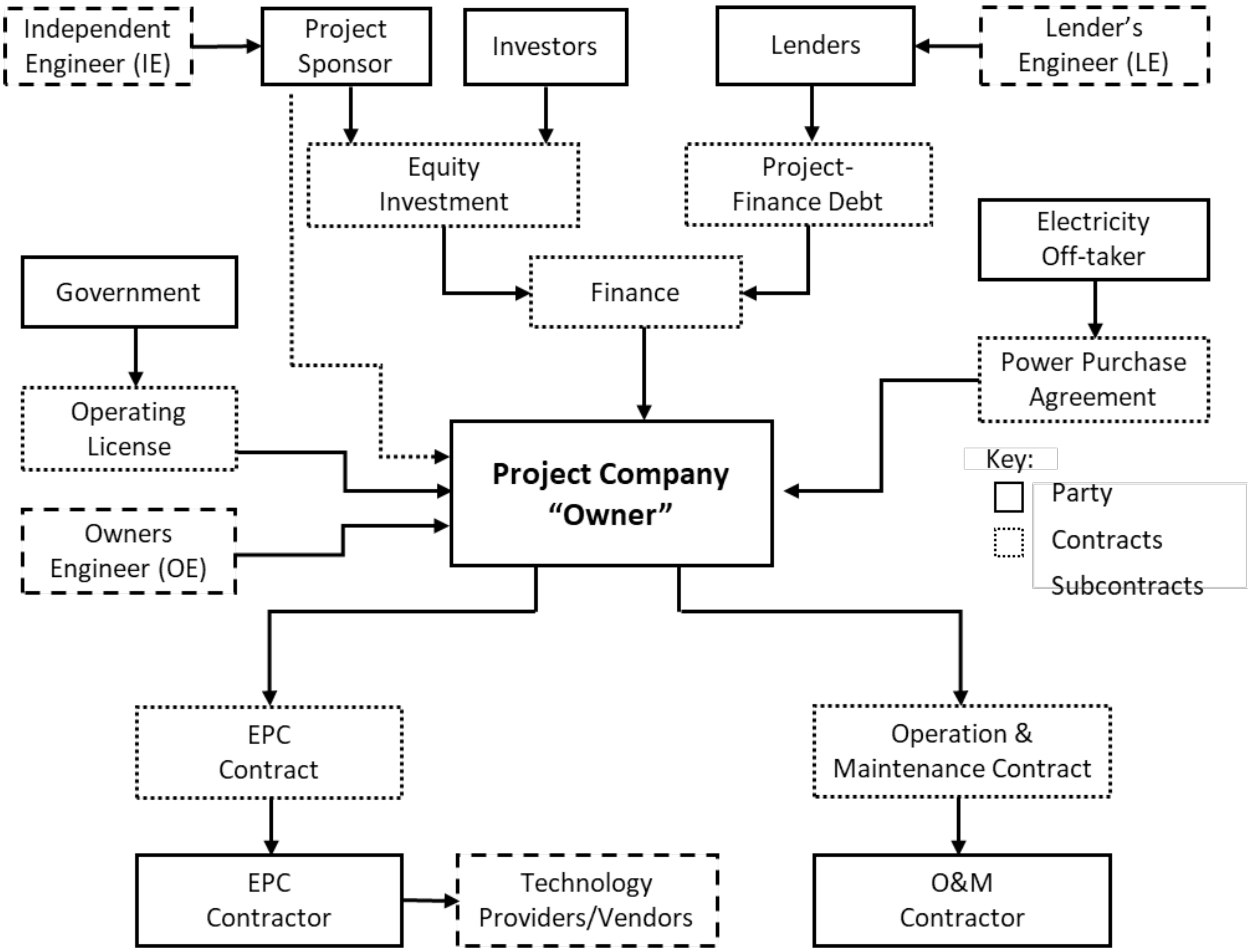

Figure 2-1. Typical project financial structure

2.1.4 Project Participants

Project Sponsor

The project sponsor is an investor that leads the development of the project and is one of the eventual equity investors in the project company or may simply be a developer that sells off the project company to equity investors. The project sponsor leads the preparation of the bid for the tendered CSP project. The project sponsor typically forms the project company and arranges necessary financing to realize the project through equity contributions and loans (debt service). The project sponsor bears the risk of the project until a certain point in financing (usually up to financial closure). When this point is reached, the further risk is then transferred to the equity in the project and the debt.

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The Project Company

The project company is a special-purpose company that becomes the owner of the physical project assets. It is formed to manage all aspects of the lifecycle of the project, and it manages all the contracts. The project company is owned by the project sponsor and any other equity investors in the project.

Investors/Equity Investment

Investors provide the equity investment for the project. This typically includes the project sponsor and additional passive investors. The investors are the owners of the project company. They will bring in any additional equity at financial closure. Projects typically use leveraged finance, which includes both equity and debt financing. Investors typically provide from 20% to 50% of the capital investment for the project; the remainder of the investment comes from loans referred to as debt.

CSP projects often have one or more of the technology providers or the EPC somewhere upstream as a sponsor or investor in the project. This is often necessary to raise enough equity investment in the project. Unfortunately, in some cases, this can interfere with the normal EPC process or with the O&M of the project.

Lenders/Project Debt

Depending on the project, there may be multiple sources of debt. Debt may come from commercial banks, development banks, or from governmental entities or governments themselves. Using debt to leverage financing typically drives down the cost of financing because the required return on equity is typically much higher than the return on debt. This allows a lower cost of electricity to be offered. However, multiple parties and leveraged financing increase the complexity of the project and require risks to be managed. The term of the PPA needs to be long enough to support financing of the project debt.

Independent Engineer

An independent engineer (IE) can be used in several roles to provide technical support to various parties in the project. The initial role of the IE is to provide technical services to the investors during preparation of the bid, prepare the owner's technical specifications, financing, preparation of tenders and selecting the EPC contractor and O&M contractor. The IE plays an important role to protect the interests of the investors, and as such, the IE is often given rights in the contracts to review and approve technical decisions in the project.

Lender's Engineer

The lender's engineer (LE) is a representative of lending institutions such as banks. The IE's role often evolves into the LE role. However, a separate engineer may take on the role of LE. The LE's function is to audit a project from the technical standpoint when a developer seeks funding for it. The role is to verify the physical status of work being implemented on the site and to judge and report the quantum of finance being contributed and used on the project. These services assure the lender against misuse of funds.

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Owner's Engineer

The owner's engineer (OE) provides technical support to the project company or owner of the project. The OE often provides technical services during the project implementation, supervising the EPC contractors' detail engineering, procurement, construction, commissioning, performance testing, and verifying performance testing for Provisional Acceptance Certification. The OE is usually contracted to supervise the operation until Final Acceptance Testing and Certification.

2.1.5 Key Project Contracts

Power Purchase Agreement

Key to any CSP project is a power purchase agreement, which is a long-term, ideally fixed-price, off-take contract for power produced. Typically, the PPA is contracted with a power utility or government entity. It is essential that the PPA comes from a creditworthy entity. The availability of the PPA becomes the key to enabling a project to occur.

The contracts typically pay for energy delivered by the project, but may also include values for capacity, duration, shape, or other ancillary services. Contracts often have time-of-deliver energy rate structures, which incentivize generation when the utility most needs power. Rates may be flat or may escalate over time. The more complex contracts enable the contracting entity to encourage developers to tailor their energy delivery and/or capacity to fit the utility's increasingly more complex actual needs. As the proliferation of photovoltaics (PV) and wind power installation continues, we expect to see more dynamic grid-stability requirements imposed to drive developers to include synchronous generators or similar equipment and operating practices to provide short-term stabilization of the grid. These newer, more complex contracts require more expertise—not only on the part of the developers, but also, on lenders and off-takers, as well.

CSP projects usually have 20-year or longer PPA terms, and most projects have at least 25-year PPA terms. Longer PPA terms result in lower PPA tariffs.

EPC Contract and EPC Contractor

The Engineer, Procure, Construct contract becomes a key part of the bid and the project finance structure. To manage project risks, the financial community prefers projects to have fixed-price, turnkey EPC contracts with a full wrap-around performance guarantee. This is especially true for CSP technologies, which are newer and less proven technologies. The EPC contractor is responsible for the design, EPC, and commissioning of the project. Very importantly, through the EPC contract, the EPC contractor takes the risks associated with technology, construction cost, schedule, and guarantees (material and performance) of the project. The EPC contractor must build a plant that works, complete it on time, build it for the price bid (or risk losing money), and guarantee that the plant will perform as contracted. The EPC contract is a large and complex document, with one of the key pieces being a technical definition of the project and its design requirements. This is often developed by the owner and is referred to as the Owner's Technical Specification (OTS). In some cases, this document is called the Minimum Technical Specification.

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O&M Contract

The Operation and Maintenance contract is another key part of the overall project. The O&M contractor may be an affiliate of the project sponsor but could be an independent party or may initially be an affiliate of the EPC contractor. The O&M contractor must mobilize a team to be ready to take over the O&M activities at the end of commissioning of the plant when the plant begins commercial operation according to the PPA. Typically, the O&M contractor is brought into commissioning early enough to allow the O&M crew to receive training and be ready to take over operation from the EPC contractor. The O&M contract is often a 5- or 10-year contract with options to extend through the duration of the PPA. In some cases, the EPC contractor may provide the O&M services for the initial years of operation of the plant; often, that coincides with the EPC performance guarantee period.

The O&M contractor is responsible to staff the project, contract the external services, and procure supplies and spare parts needed to support the O&M of the plant. The operator is also responsible to make sure the plant maintains all permits and reporting requirements. The O&M contractor often leads the performance analysis of the plant and implementation of improvement programs that attempt to improve the economic performance of the plant for the owner. More detailed discussion of O&M topics is covered in Section 4.

Finance Contracts

The financing contracts are a key element of a successful project. The financing provides the funds that enable a project to be built and operated for the financial life of the project. Financing comes in the form of equity and debt. *Equity* refers to direct investment or ownership in the project. The equity makes a return if the project makes money after all expenses are paid. *Debt* investment, on the other hand, is a loan from a bank or other organization. The debt is typically a long-term loan with a fixed interest rate. The loan and the return on the equity investment are paid with revenues from the PPA.

A project is only able to go forward and reach financial closure if all the parts of the deal are sound. The EPC contract becomes a critical part of the overall project. Although the EPC contract is between the project company and the EPC contractor, many of the requirements in the contract are obligations to address risk to investors, banks, the off-taker, and others. An EPC contract is intended to make sure that the EPC contractor builds a plant that operates as intended in the PPA, performs as contracted in the financial pro forma, and has projected O&M costs that are in line with that expected in the financial pro forma.

Other Contracts

Many other contracts are important for the project, including interconnection, land, water, supply contracts if outside of EPC/O&M, insurance, and more.

2.2 Project Phases

A CSP project can be divided into three general phases: development, execution/implementation, and commercial operation.

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2.2.1 Development Phase

The initiation of a CSP project is usually in response to a Request for Proposal (RFP) for new power generation or to a response by a developer to a FIT or other. Clearly, there must be a financial motivation to develop a project. The nature of the request or opportunity will likely define the configuration of the plant that should be proposed. In some cases, an RFP is for a specific plant configuration; in other cases, the specific technology and configuration is left up to the developer to propose.

For tendered projects, a main part of the development is prepared by the utility, selecting the site and defining the off-taker's requirements and includes the PPA.

In other cases, the development phase could be a part of the IPP proposal. Such a development phase includes the conceptualization of the project, site selection, site assessment, permitting, negotiation of agreements (including interconnection, PPA, water supply, backup fuel supply, concession agreement, financing, and security agreements for financing of the project). Depending on the nature of the project, the development phase may include a detailed competitive proposal process for selecting the team that will be awarded the PPA. The site selection and permitting process may already be done or may need to be done by the project team.

Conceptualization of the Project

The first stage of IPP engineering is often referred to as conceptual engineering. This defines the basic configuration of the plant. Enough detail is needed to allow an adequate cost estimate to determine a bid price as well as to support permitting requirements. There is generally design optimization at this stage to develop the plant configuration to meet the appropriate market requirements and to attempt to minimize costs.

Site Selection and Permitting

In some cases, the site selection and permitting is provided by the agency tendering the project. In other cases, the IPP's development team must identify the site and obtain permits for the project. For CSP projects, site selection and site assessment are very important tasks and have significant impact on the competitiveness of the project. Key elements in site selection for a CSP plant may include: proximity to transmission lines, the solar resource, the topography and soil characteristics of the site, availability of water, sometimes access to natural gas, as well as access to rail and roads that can handle robust construction loads. A more detailed discussion of these issues is described in Section 2.4.

Bid and Negotiation

In most cases, a bid of some format is required. Generally, there are two types of projects: the first is an open solicitation where the project sponsor selects a site and proposes a plant design; the second case occurs when a very specific plant design is requested at a predetermined site, with off-taker's agreements (PPA) and connection agreements. In both cases, this may be a multi-stage process to first qualify teams to propose and then one or more bidding phases. The project sponsor is typically responsible for submitting a high-quality, competitive bid. The RFP often requires detailed information on the project design, key equipment, the project team and demonstrated experience, financing plans, site assessment, and permitting. The key evaluation

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criteria are the performance forecasts defining or meeting the PPA requirements. In the case of competitive bidding, one or more bids may be short-listed for negotiation of the PPA.

Financing

If the bid is selected for the award of the PPA, then the sponsor moves forward with financing of the project and establishing the project company. All the main agreements and contracts are negotiated with the project team. Financial closing occurs when all the parties are ready to sign the final agreements and contracts (EPC and O&M) and various financing documents; and it leaves no high-risk contract open, including supply of major equipment or technology, either through the EPC or directly with the project company and assumed by the EPC. These documents are then signed with the project company.

The financing provides construction loan funds to the EPC to implement the project. In projects in the United States, there may be a second financing step that occurs following commercial operation date once the initial performance test is completed that guarantees that the plant is operational and ready to go into commercial operation and start generating revenue. At this time, for tax reasons, the long-term financing is put in place.

2.2.2 Execution Phase

This is the implementation phase of the project. This typically follows financial close of the project and carries through to initial acceptance (IA) and COD, when the project is turned over to the operator for commercial operation. This includes the detailed engineering, procurement of all equipment, construction of the plant and infrastructure, commissioning the plant, and initial performance tests.

Following financial close, the EPC contractor will be given full notice to proceed. This will kick off the remaining detailed engineering activities, initiate procurement (if not already initiated at project sponsor risk to meet timelines), and start the mobilization of the construction team at the project site. In some cases, the EPC contract may include a limited notice to proceed (LNTP), which authorizes early work to begin, before financial close. This is often used when the project schedule is short or there are long procurement times on some equipment. This typically is to complete the engineering for procurement of these long-lead items and get a head start on critical-path detailed engineering activities.

At the end of the execution phase, the EPC conducts the initial acceptance testing that is observed by the owner, OE, and LE. The testing will confirm the operability and efficiency of the main systems in the plant (solar field, thermal energy storage, and power block) and the plant is ready to be turned over for commercial operation. Section 3 focuses on the details of the execution phase of the project.

2.2.3 Operation Phase

The operational phase starts when the EPC contractor turns over care and custody of the project to the O&M contractor. This usually occurs at IA and typically corresponds to the COD of the PPA. In most plants, the formal turnover of the complete plant to the O&M contractor signals the start of the final acceptance test (FAT) for the EPC contract, which may run for multiple years.

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Even though the CSP plant has been tested for the provisional acceptance, it is generally considered necessary for CSP projects to evaluate the performance of a CSP plant over an entire year. This is because the position of the sun in the sky changes throughout the year, and the solar resource—and therefore, the plant efficiency—also changes. It is considered necessary to evaluate the performance of the plant over the year to make sure it performs to expectations. Additionally, experience has shown that it typically takes some time for the plant to be tuned to achieve peak operational conditions. Part of this is the learning curve needed by the O&M team.

As a result, the developers' and lenders' advisors typically suggest that a ramp-up over one or more years is needed to optimize the process and to reach the guarantee values for final acceptance. This is often referred to as the FAT or something similar. The EPC and O&M contractors' obligations are to reach 100% guarantee values over 1-year operation. For example, some projects have assumed 80% of design performance in year one, 90% in year two, and 100% in year three. Often, if the design performance of 100% is met earlier, then the final acceptance can be certified early.

During the FAT, there is often an overlap in responsibility between the EPC contractor and the O&M contractor. The O&M contractor is typically responsible for operating the plant, often under the guidance of the EPC contractor who is responsible for the performance of the plant. In addition, the EPC contractor typically has an equipment warranty during this period. This creates a situation that can cause issues for determining responsibility for any underperformance or corrective actions that may be required. These issues can tie to the EPC contractor's liquidated damages (LDs) and warranty guarantees.

When the project reaches commercial operation, the revenues from the sale of energy are income to the project company. From the income, the project funds the plant O&M, makes the principal and interest payments to the banks, and provides the returns to the equity holders. The operational phase runs for the full financial lifetime of the project, typically 20 to 30 years or longer.

2.3 Project Owner or Project Company

As previously described, the investors in a project are the owners of the project who provide the equity necessary for launching loans and establishing the project company. During the early stages of a project, the project sponsor may be the only equity investor in the project; or, if there are multiple equity investors, the project sponsor usually takes the lead on the project. Additional investors may come into the project at financial close or at commercial operation. However, during the development and execution phases of the project, the project sponsor usually has control of the project. For purposes of discussion, we refer to the project sponsor and equity investors singularly as the owner of the project. This section discusses issues and best practices associated with the role and responsibility of the owner and the owner's technical specifications.

2.3.1 Roles and Responsibilities

Most successful CSP projects have owners that have a strong understanding of CSP technology and who play an active role throughout the process—from bid preparation to operation. All CSP projects begin with the owner's decision to bid and then implement a CSP plant. The owner is responsible for preparing a proposal to bid on a CSP plant, and, if appropriate, to negotiate agreements with off-takers (PPA), connection agreements, permitting the site and plant, *contracting with EPC and O&M contractors, securing the necessary financing, and establishing the project company.*

The EPC contract is usually a fixed-price contract, and any cost overruns are a risk that rests with the EPC, thus making cost and schedule control their number one priority. Most EPCs understand how initial cost and long-term performance are related, but minimizing investment does not necessarily minimize total project cost to the owner.

A part of bid preparation is to select an EPC contractor and to negotiate the EPC contract ready to be signed. The owner needs to prepare a tender document and the contract for the EPC contractor. A part of the tender document—and later, a part of the EPC contract—is the OTS, which provides a specific requirement on design and the work of the EPC contractor.

Another part of bid preparation is to select an O&M contractor and to negotiate the O&M contract ready to be signed. The owner needs to prepare a tender document and the contract for the O&M contractor. Such tenders generally comprise a long-term O&M contract with an operator, although the term will vary from project to project depending on factors such as the location, technology, and PPA terms. The operator may be a sponsor, particularly if one of the sponsors is an IPP or utility company whose main business is operating CSP plants or similar power plants. In some financing structures, the lenders will require the project company itself to operate the plant.

Because CSP technology is at a relatively early stage of commercial maturity, it is important that the owner thoroughly understands the CSP technology; but if the owner does not, then the owner should hire an experienced IE, OE, and eventually an EPC contractor with a thorough understanding of the technology. The owner and the OE should be actively involved in preparing sound specifications for their CSP plant and, where they exist, to reference appropriate codes and standards.

An experienced IE or OE can help the owner set up the project's architecture that respects all the interests of the owner, financing institutions, and subsequent project partners. But the IE should prepare the tender and contract for an EPC contractor including the OTS.

The owner is obviously concerned about the long-term performance of the plant—its operations and future costs, as well as the investment cost of the project itself. Owners need to be actively engaged at every stage in the development of their CSP plant, which is not always the case. This involvement will likely result in slightly higher initial expense; but that investment will be recovered over the life of the project and may even have a significant return on that investment. And the owner needs to be involved to ensure that the OE is doing its job, which includes ensuring that the EPC is doing its job. The OE should be actively engaged in reviewing the detailed design and engineering because inadequate design or engineering results in problems all the way through construction and into operations.

Once an EPC is selected, the sponsor and the OE should assure that the EPC performs as defined in the EPC contract.

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Best Practices

- The sponsor/owner should be an active participant in all phases of the project including development, engineering, construction, and commissioning.
- The owner should hire an IE and OE who is experienced with the CSP technologies used in the project.
- If the owner does not have in-house capacity for preparing the bid and implement the project, then the owner should hire an external consultant to review the IE and OE contracts before signing and can review their work.
- The OE and IE should be actively engaged in reviewing the design and engineering and review and comment on the processes, equipment, and plant configuration recommended by the EPC contractor.
- The owner should hire an OE who is experienced with the CSP technologies for supervision of the EPC contractor during the project implementation.

2.3.2 EPC Contract

The contract between the EPC and the owner is perhaps the most important of the many project contracts. The EPC contract can be prepared by the owner or by the EPC contractor. The EPC contract will need to be reviewed by the owner, OE, IE, lender's technical advisors (LTAs), and other parties involved in financing the project.

OTS: The owner typically prepares a design requirements specification document commonly referred to as the owner's technical specification, which will be included in the EPC contract. The OTS is discussed in more detail in the next section. The EPC contractor prepares a technical and financial proposal that may provide deviations to the OTS and other owners documents submitted in the EPC contractor's tender. The EPC contractor proposal after the negotiation with the owner and the owner's consultants will become a part of the EPC contract.

Given the relatively early commercial maturity of CSP technologies, many participants commented that providing a detailed and clear OTS in the EPC contract was very important to having a successful project and avoiding significant conflicts during construction. Although certain design requirements are defined in the OTS of the EPC contract, the point of the EPC structure is to put all the requirements for designing the project properly in the EPC's hands. It is important that the OTS specify actual owner requirements and not attempt to design the plant. In any case, it is important that the owner and the EPC work together to clearly define and agree upon the OTS in the EPC contract.

A common misconception among many project participants is that an EPC will optimize the plant for overall lifecycle cost. But an EPC contract typically provides an electricity-generation guarantee of a period of one to a few years. So, the main drivers of EPC design are often to minimize cost and electricity generation during the first few years of operation. To optimize the plant for long-term performance, the owner and OE must perform adequate engineering studies and preliminary design requirements that can be properly translated into the OTS to be included

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in the contract with the EPC. Adding a maintainability metric in the EPC contract may help, but it may be difficult to scope.

All EPC contracts eventually have some sort of change-order provision that increases the owner's cost. Change orders often result from changes in the owner's requirements in the middle of construction. A strong and well-crafted OTS will minimize the number and magnitude of changes required.

The EPC contract shall have a clause of a priority of documents; it lists the contract documents in order of precedence. For example, the OTS shall have higher priority than the EPC contractor's technical proposal.

Communication and Trust: After the EPC contract has been signed, the EPC will try to fulfill its contract to the lowest possible cost. As a result, it is important that there be strong communication between parties, and they must be defined in the EPC contract.

The owner is recommended to have a qualified team in place to supervise the EPC contractor's activities. Because the owner (and OE) cannot oversee all of the EPC's activities, there is a need for coordination and building trust between the EPC and the owner. The EPC contract and OTS should document the intended communication and coordination required for the owner's oversight.

Project sponsors may lack the experience or knowledge to adequately draft the EPC contract, and inexperienced EPC contractors may lack the experience or knowledge of the complexity of such projects to properly negotiate this contract. In this case, it is very important that CSP-knowledgeable IEs, OEs, or LEs are involved in developing the EPC and other contract documents.

EPC Experience: The track record of the EPC with the specific CSP technology to be implemented is very important. For example, a participant stated that for one project, the owner had insufficient experience to adequately define the EPC contract, and the EPC contractor did not realize the complexity of the project. EPC qualification and selection criteria should require experienced personnel with CSP background for all the main positions in engineering, construction, and commissioning phases.

EPC firms with little or no local or in-country experience are likely to run into design, cost, schedule, work, and culture issues. It is desirable that the EPC team have strong in-country experience.

It was noted that no EPC, regardless of how many past CSP projects built, will necessarily use staff with experience from previous projects. Therefore, not all lessons learned from previous projects are transferred to the next project because each project has new hires for most of its staff. In the best-case scenario, only a handful of people with experience from past projects will work on the next project.

Owners that are Technology Providers: In the early-stage projects in CSP, it has been common for technology providers to be owners in projects. The owner is then forcing specific technologies to be used in the project. This is not necessarily a problem; however, if the

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technology does not perform, it can become a problem for the project to resolve the issues. This needs to be clearly addressed in the contract documents.

Milestone Payments: Several projects have indicated that there was not a clear relationship between the milestone payments in the EPC contract and the work progress on the project. In some cases, milestone payments were event-driven and not based on work completed. The EPC payment structure needs to be managed such that the work and subsequent value put into the project closely aligns with the amount of money paid to that point to the EPC. If an EPC gets far ahead on payments and then disappears, then the value in the project is what is already completed. So, the ability to recover depends on the mismatch between the amount paid and the actual value.

Engineering: Several participants indicated that on a number of projects, the engineering was delayed, thus impacting the procurement and construction activities, and often causing a chain reaction of issues experienced through commissioning and into operation. It is important for engineering to be completed on time, ahead of when it is needed. This is often difficult due to tight EPC schedules. Engineering needs to be carefully managed and tracked early in the project.

One approach to help with the tight schedule for engineering is to complete some engineering ahead of a full notice to proceed and initiate procurement of long-lead items. This can be done by the project sponsor and IE/OE or by the EPC contractor. If performed by the EPC contractor, this requires the EPC to be given an LNPT prior to project financial closure. Either approach increases the amount of early funding that must be provided by the project sponsors. If the owner's OE has produced a conceptual design ready for detailed engineering, then many of the long-term delivery components can be procured before the EPC is given the LNPT. The LNPT should generally cover civil work and focus on power island or other critical-path items. In many projects, the solar field is completed long before the power island.

Problem Resolution: The EPC contract should motivate the EPC and the owner to fix a problem rather than let it be allowed to reoccur, and the EPC should be incentivized to not have disputes and for the timely resolution of issues. The historical approach has been to specify sufficient penalties in the form of liquidated damages for schedule delay and the imposition of "replace and rework" requirements such that the EPC contractor is motivated to speedily resolve the issues. They should: (1) strengthen the relationship between all parties, align the outcomes with risk and reward, make sure there is full transparency between parties (problems cannot be solved if only one party has full information); (2) incentivize the EPC to not have disputes and for the timely resolution of issues; and (3) encourage better coordination between engineering and construction, which always helps. If the engineering is done by a different company, then it is important that there be trust between that company and the EPC contractor.

Liquidated damage clauses in EPC contracts are not always sufficient motivation to induce the desired compliance with either speedy repair and rework or with schedule compliance. The EPC may believe his or her negotiating position will be enhanced if disputes are postponed to the end of the project. Sometimes, when careful records have not been kept, one or the other of the parties may propose simply splitting the claims "down the middle," rather than negotiating each of the issues. It is typically best for both parties if issues are identified and addressed quickly.

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Delay penalties or liquidated damages may cause parties to overlook some equipment protections during commissioning. This could cause irreparable damage to key equipment or result in a reduction in their service lifetimes. Some have suggested that lowering penalties/LDs in the EPC contract and increasing the owner's role in project supervision during construction and commissioning works would help both parties to achieve the goal of a new CSP plant that operates with no important disruptions and fulfills performance expectations.

The EPC contract should include penalties for inappropriate risk taking need to include considerations for equipment and personnel safety as well as safe and expeditious commissioning. This can be addressed by adding a clause to the EPC contract such that all key equipment will be instrumented to adequately identify if equipment limitations are maintained, and no equipment can be operated outside of its design limits (even for commissioning, even if briefly, because it may reduce the equipment lifetime and leave equipment with latent damage). On recommendation was that DCS trending and data historian capabilities should be installed early so that commissioning of all major equipment can be monitored.

Transition to O&M: Many EPC contracts incorporate clauses that require the EPC contractor to facilitate an "operator's mobilization" during the final months of construction. For this mobilization period to be effective, the EPC contract should include some provisions that require the EPC contractor to involve the operator in the commissioning activities and provide them training on the plant equipment and operation procedures of the plant. However, the actual implementation of these provisions has often been unsatisfactory. Several operators have suggested that some EPCs are not enthusiastic about having operators present during commissioning and do not dedicate the necessary efforts and resources for operational training to be done effectively.

Performance Guarantees: Sometimes, it happens that some of the methods used to determine the guaranteed performance values are not to the satisfaction of either party. The actual operating conditions often differ from expectations, and this leads to disagreements, especially from the owner's perspective. Or the specification of the calculation methods for predicting and measuring actual plant performance is imprecise. More industry-specific standards would be a benefit here. In addition, delay claims from the EPC contractor can occur due to cost overruns that cannot be allocated to *force majeure* events and may have to be borne by the EPC contractor. Other issues arise related to, for example, the water supply and quality, geotechnology, liquidated damages, warranty, spare parts, training, responsibilities after turnover, commissioning, turnover and as-built drawings, just to name a few.

In addition to transparency in modeling mentioned above, it is recommended that there be transparency in the input assumptions used in the model. A number of EPC contracts have used assumptions that appear to unfairly favor the EPC over the owner. Although the overall performance projections appear reasonable, the model uses very aggressive availability assumptions that the owner/operator are responsible for and very conservative efficiency assumptions that the EPC contractor is responsible for. It is better to develop a common industry basis for what are reasonable assumptions, so that owners and investors can understand where assumptions are aggressive or conservative; this will allow for better understanding of the performance risk profile of the project and also for fair competition between bidders.

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The EPC contract often does not clearly define the EPC contractor's obligations related to operations between initial and final acceptance; so, it remains up to the EPC contractor and the owner to work this out. This is typically the EPC performance guarantee period. During this period, the owner will claim the EPC is responsible for underperformance, and the EPC contractor will claim the operator is responsible for the underperformance of the plant because the operator did not operate the plant according to the O&M manuals. Typically, this ends up in lengthy and complicated discussions between the EPC contractor, owner, and operator, or legal arbitration. And such claims are usually not easy to "prove." It is best if the approach to be used is well documented in the EPC contract.

Some EPC contracts try to define the process to be followed between initial and final acceptance—to precisely address these issues as soon as possible, instead of 2–3 years down the line when assessing final acceptance. For this to work, unedited information needs to flow in real time. One of the best solutions to this issue is to have the O&M contractor involved in the project early and to have the contractor fully mobilized and trained in time to take over operation at initial acceptance.

With strong damages, the performance guarantees are high priority. What may not be well contained is the O&M cost, and the EPC will favor lowering capital expenditure (CAPEX); but there is also a risk that the owner may not adequately invest in O&M, resulting in a gap in the contracts. It is important that the O&M contract includes adequate resources during the EPC stage for the mobilization and training of the O&M team. Some projects may rely too much on the EPC to train the O&M contractor. The most successful projects seem to have an experienced O&M contractor who is responsible for managing the mobilization of its systems and training of its staff, working with the EPC to coordinate training of equipment and systems as appropriate. Many projects have the EPC manage the commissioning process but using O&M personnel to operate the plant. This can also help with developing final operating procedures, because the operating procedures and control-logic changes determined during commissioning can be updated on the spot.

Best Practices

- The owner needs to pay great attention to the assembly of a project team that can cooperate because the success of the project depends on its team. If the team is lacking the necessary skills (especially communication) or is not united or motivated enough, the quality of a project will suffer.

- The EPC contract should define a management structure that will enable realistic project delivery timelines and efficient planning such that the project has sufficient time for design reviews, acceptance of equipment, testing, and finally, the acceptance of a well-performing plant with a manageable punch list.

- To improve clarity, owners and EPCs should involve lawyers and technical experts familiar with CSP plants when preparing and negotiating the EPC contract.

- Depending on the in-house capabilities and experiences of the owner, an IE with appropriate CSP experience should support the drafting of the contract with the EPC.

- The EPC contract needs to include an OTS that includes clearly defined operational intent and critical design requirements. Avoid an OTS that has demands that are unrealistically high and/or unreasonable and/or unclear, which lead to change orders and claims during the implementation.

- Avoid situations where the project is started before financial closure and where the technical requirements are changing all the time after the design is completed—or even worse, after the work is being implemented.

- Owner's or OE's supervision of the EPC's construction and commissioning work can help both parties to achieve the goal of a new CSP plant that operates with no important disruptions and fulfills performance expectations.

- The EPC contract should include a payment structure that is based on work progress completed. What needs to be avoided is putting financial risk on the project by overfunding the EPC while having less-than-paid-for value in the project. The most cost-effective approach is when the EPC is funded through low-cost money from the project with just enough time to pay their bills. That is the balance that this exercise aims to achieve.

- The EPC contract should focus on timely completion of engineering. Construction should not be allowed to begin until engineering is sufficiently complete to avoid delays and rework. Ideally, a significant portion of engineering should be completed prior to starting construction. Most importantly, a working 3D model should be ready and used to document execution and field changes. It needs to have dedicated people who work with activity managers for each construction phase to continuously update the model.

- The EPC and the owner should be motivated to fix problems rather than let them languish unresolved or reoccur, and the EPC contract should incentivize parties to avoid disputes and to resolve issues in a timely manner.

    - EPC contracts should include a binding dispute-escalation mechanism to ensure speedy conflict resolution. The key lies in a mechanism to automatically escalate the resolution above the project-manager levels. For example, if the two project managers cannot resolve the issue within a defined time period—say 60 to 90 days—then a meeting between the corporate vice presidents is automatically triggered. After another 60 to 90 days, if the problem has not been settled, then binding mediation is invoked. The key to such a dispute-escalation mechanism lies in specifying firm time intervals and trigger mechanisms so that languishing issues mandate escalation by the participants' management or by formal mediation.

    - In some cases, the mediation mechanism has been overseen by the lender(s), who have a significant financial interest in the speedy resolution of disputes.

- The industry needs to develop thorough industry-wide test code for solar-plant acceptance.

- An EPC with good track record in power generation is as important as having CSP experience.
    - The EPC should have a track record for building quality projects, on time and on budget. Check with previous customers, visit completed projects, and get firsthand feedback on the EPC's performance.
    - In addition, the EPC should have experienced personnel with CSP background for all main positions in engineering, construction, and commissioning phases as well as local or in-country experience.
    - The EPC should seek project team members and partners who have proven expertise and ability to work well together.
    - When selecting an EPC, avoid contractors who have a reputation for solving problems only by dispute.
- In addition to the requirement for experienced management personnel with CSP experience, staffing stability and continuity in the key management positions is vital. In one case, the EPC contractor replaced the site construction manager six times in a three-year construction period. The obvious turmoil that such turnover engendered was exacerbated by the fact that none of these managers had experience in the culture of regulatory compliance, local union practices, or subcontract administration in the project country. Add to this the fact that the language of the project team, the subcontractors, and the construction workers was a foreign language for these site managers and the potential for ensuing turmoil is obvious.
- In addition to the complication inherent in adapting to a foreign regulatory regime, an EPC contractor must also understand the differences in labor markets, labor laws, and work rule common practices. The culture of the local subcontracting market may be radically different from what the EPC is used to.
- In large projects, multiple EPCs may form a joint venture to build the project. In these cases, each company should be fully responsible for all LDs, the joint venture should establish a liaison between consortium members, and consider embedding employees of each consortium member in the other company(s).
- The strictness of enforcement by local regulatory authorities varies tremendously between countries. In some countries, the requirements of local authorities are barely addressed or may be subject to pressure from the EPC. In other regimes, the regulator can stop work until strict compliance is documented. These regulators can ensure compliance with local laws in areas of health and safety, in QA/QC inspections, or in building-code compliance, such as enforcement of fire protection, electrical grounding, or other requirements. If the EPC contractor is operating outside of the culture with which he or she is familiar, then the best practice is to hire a local expert to advise the EPC.
- Ensure consistency between obtaining handover from the EPC contractor under the EPC contract and owner's obligations under the PPA for commercial operation. For example, the measurement methodology shall define performance-measuring instrumentation

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(external calibrated instruments versus installed instrument for operation). It is desirable to prescribe back-to-back testing under the relevant PPA and the EPC contract that will result in smoother progress of the testing and commissioning and will better facilitate all necessary supervision and certification. However, one needs to make sure that the EPC is not held captive to the availability of government/utility employees that need to witness the test.

- The EPC contract should clearly define that the appropriate party corresponds with the relevant off-taker during construction on issues such as the provision of transmission facilities, fuel requirements, testing requirements, and timing. The project company is typically the appropriate party to correspond with the off-taker.

2.3.3 Owners Technical Specifications

The owner needs to convey its design requirements to the EPC without voiding warranties and to minimize change orders and potential claims. It is a challenge to find the balance so that the owner does not provide too much detail such that the owner risks over-specifying the plant for the EPC.

The OTS is a document that is included as part of the EPC contract that defines the owner's technical requirements for the plant (note: this is sometimes referred to by a different name, such as Minimum Technical Specification). The OTS must be detailed enough to set out the inputs into the EPC contract, EPC contractor's proposal-technical specification, and then for the detailed engineering, dealing with all major and important aspects of the plant (e.g., power-block selection, steam-generator design, the need for and specifications of heat tracing, number of elevators, and more).

The OTS must find the right balance between providing too much detailed information such that the owner risks over-specifying the plant for the EPC and letting the EPC design it, based on the specified minimum acceptable performance.

The owner aims to set out in the OTS the technical details that can ensure the EPC contract clarity of delivery and performances. However, for a number of reasons—including the fact that it is often not possible to fully scope the detailed deliveries and the testing programs until the detailed design is completed—the detailed deliveries and testing procedures are usually left to be agreed on during construction. For this reason, the OTS shall be structured in the way to consider these facts and avoid specifications that can become unreasonable or counterproductive. The EPC contract shall foresee the approval procedures of relevant detailed engineering documents by the project company's representative or OE or IE and, if relevant, the LE.

The OTS can include a qualified vendors list, which is common for key equipment, and it can require approval of selections outside of that list.

It has been suggested that the OTS should contain lessons learned from prior projects. One approach is that the owner and EPC review and modify the OTS in a detailed interactive workshop, and any clarifications are then included in the contract between the owner and EPC.

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In addition to a strong QA/QC program, adherence to industry standards such as codes, acceptance criteria, and testing guidelines is essential. Some owners may object to acceptance criteria, testing guidelines, and more that are not in the contract and presented by the OE during an activity. So, defining the essential ones matters most.

One thing missing in CSP design is an overall reliability model that statistically shows all components in series and parallel with their failure rates, mean time between failure, and mean time to repair—calculated to show how the availability of the plant will be high. The EPC contract focuses on energy production; but availability is a subset of that, and availability is also related to maintainability. With such a model, one could then identify an amount of maintenance required by design. This approach could help appropriate availability assumptions to be used in performance projections and performance guarantees.

One EPC stated that a good detailed OTS helps to reduce the uncertainty of the owner's requirements and improves the interaction between the owner and EPC.

Best Practices

- The OTS should be presented by the owner to the EPC in an interactive workshop, line by line, to explain the operational intent and the need for equipment redundancy, and to explain why and how each item is important. Any emerging clarifications should be included in the EPC contract.

- In general, the OTS should specify performance requirements rather than mandate specific design details or equipment brands. In some critical cases, however, where the owner has specific and sometimes empirical experience from past CSP lessons learned, specific designs and equipment brands can be suggested or mandated. This is particularly true with first-of-a-kind equipment and first-of-its-size equipment.

- Because the OTS is critical to the project, it is recommended that the owner use an IE to assist/develop the OTS.

- Every effort should be made to anticipate needs to avoid change orders and to allow the EPC to control costs. In that way, the EPC will better understand the owner's requirements and find technical solutions and providers that comply with them.

- The owner shall ensure that the EPC contractor shall provide comments on and deviations from the OTS to avoid unreasonable "build to spec" and also to allow the EPC contractor to suggest an improvement and more effective design that might lead to a more competitive bid.

- Based on the OTS, the EPC should develop adequate and complete functional specifications and process engineering so the plant can be operated within vendor requirements during off-design conditions including low loads, transients, start-up, and shut-down.

- Use of international codes and standards and acceptance criteria would tend to minimize or avoid conflicts; however, this will likely be determined by the local authority.

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- Avoid OTS demands that are unrealistically high and/or unreasonable and/or unclear, which lead to change orders and claims during the implementation.

2.3.4 CAPEX vs. OPEX

Tradeoffs between a winning offer and reliable long-term plant performance are a major reality of power-plant project development. The conflict between needing to offer a competitive bid—and thus, low CAPEX—and have sufficient plant performance and reliability without needing significant operating cost (OPEX) is the root cause of many technical issues.

Too often, the focus of many project participants is only on the initial capital cost of the project. There is a need to rethink and focus on improving the underlying overall value of the delivered plant. Projects should focus on the value of the plant for 25–35-year operation to ensure that the plant realizes the business case of the investment. Execution strategies where the contracts act as a coherent whole to ensure and reward the long-term plant performance offer the greatest opportunity for success.

This issue is a concern for all power-plant technologies. It is a constant significant and pervasive source of conflict, with multiple examples across numerous CSP plants. It is generally observed that attempts at savings in CAPEX often lead to more issues in the operational phase of CSP projects. A simple example of this is whether to pay for a quality valve or a cheap valve. The cheap valve may save CAPEX, but it may not work when it is needed, resulting in underperformance and increased OPEX. Appreciation of this issue is increasing in the industry, and lessons are being learned and applied. Spending more to get a more reliable solution for a certain requirement typically leads to better results. One solution to this problem lies in ensuring greater definition of detail within the OTS.

This issue is usually understood by experienced teams who have had to live with the consequences of saving money during the design and construction phases on the long-term operation of their CSP plant. Inexperienced teams will need to learn these lessons. Projects need to be designed, procured, constructed, commissioned, and operated by teams who are experienced and understand the CAPEX/OPEX tradeoff issues. This has cost implications that must be considered when bids are prepared. Standard specifications and definitions for industry will help. These definitions are for interfaces, warranty, availability, and cost/scope.

Significant CAPEX reductions have been realized through equipment manufacturer cost reductions, supply-chain diversity, and increased EPC knowledge and competitiveness. The impact on overall plant performance, availability/reliability, operability, and maintainability is yet to be determined.

More focus needs to be given during the early conceptualization of the plant and during the detailed design of the plant to ways to effectively reduce the OPEX of the plant. OPEX is one of the main economic issues of CSP technologies. In most plants, OPEX has been greater than initial financial forecasts.

Best Practices

- Provide sufficient detail and explanation within the OTS to define the minimum technical requirements needed for equipment to have good long-term performance.

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- It is best to work with EPC teams that have a proven track record for providing quality plants with demonstrated cost and long-term performance (even with no or only limited CSP project experience).

2.3.5 Project Team—Vertical vs. Horizontal Integration

The standard project structure assumes that different entities play each of the roles in the project structure. This is generally referred to as horizontal integration. Vertical integration refers to a single company taking on multiple roles in the project structure. Commonly, the O&M company is an affiliate of the project sponsor; but in many CSP projects, the project sponsor or the EPC may also be a provider of key technology, often the solar field or the receiver in molten-salt tower plants.

In the case of CSP projects developed by one vertically integrated company, affiliates acted as the project sponsor, primary equity investor, OE, O&M operator, EPC, and provider of the solar-field technology. Vertical integration allows the technology risk to be managed by one company, and it allows one company to roll up the margins that would otherwise be shared across multiple companies. In theory, this allows a more cost-competitive project, underperformance can be managed, and transparency can be better for problem solving. For example, in this case, conflict resolution between the developer, EPC, and operating company was handled within the parent corporate management instead of between these entities and the owner.

In theory, vertical integration helps enable the advancements in technology because the vertically integrated company is incentivized to find improvements to make the technology more profitable, and it is more likely to take the risk to implement new technologies.

A downside of vertical integration is the potential for lack of transparency at the project level. Although vertical integration would appear to be an excellent way to create an experienced team that could deploy high-quality and cost-effective projects, it depends on the motivation and quality of the management team. The roles of the IE and LTA become important to track project progress to make sure the owner and EPC are looking out for the long-term interest of the project. It is important that transparency needs to be clearly defined in the EPC contract.

A second downside to highly vertically integrated teams is that there is no competition for selecting the EPC contractor or the key technology. As a result, the project may get subpar contractors and technology, and less competitive pricing from these entities. Vertical integration can also be used to prevent newer or better technologies from competing in the market.

Teaming between companies has also been used to form a vertically integrated team. This approach gets around some of the issues of vertical integration. A partnership requires communication between teams, allowing more transparency in decisions. It also allows partners to be selected based on the quality of their capabilities or products and their pricing. It does require effective communication between companies, which is often challenging, especially for companies with different cultures.

Vertical integration seems to be important for new emerging technologies. As the technology matures and becomes more of an "off-the-shelf" commodity product, the market is likely to move away from vertical integration to a more competitive horizontal project structure.

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In many projects, EPCs may provide investment into the project as an incentive to be selected for the project or to enable the project to move forward. If the EPC is part of the project ownership, it can be difficult for the project to pressure the EPC to perform. Similarly, if a technology provider is part of the project ownership, it can be difficult to get the technology provider to perform. If appropriate, the EPC contract needs to account for either of these situations.

Best Practices

- If the EPC is part of the project ownership, it is important to have the project company managed by an independent entity and to make sure the contracts give the independent engineer a clear role in reviewing and approving work completed by the EPC.

- Teaming by EPCs and key vendors can provide a project team that benefits from the advantages of vertical integration without many of the negatives. This approach helps reduce the risk of the project depending on a single company and provides the opportunity to pull in partners with competitive technologies, capabilities, and pricing.

2.3.6 Additional Recommendations from Participants and Reviewers

This section contains comments and suggestions from participants and reviewers in relation to project structure that have not been address in previous sections.

Alternatives to Traditional EPC Contracts

Most EPC contracts have a firm fixed price with liquidated damages for schedule delay and reduced performance. Most financial institutions prefer this approach, assuming it will provide the most protection from risk. However, for emerging technologies such as CSP, this may not always be the case. The technologies are new and unproven, and the EPCs do not necessarily understand the technologies sufficiently to correctly engineer and construct the projects at the time of bidding.

For large projects, it may be difficult to find one EPC capable of doing the needed work and providing the needed guarantees. In those situations, multiple EPC firms can form an EPC consortium; but a consortium brings additional management challenges and could be subject to conflicts between its members. Different companies have different cultures, standards, and methodologies. Situations have occurred where there were issues that, if addressed early, could have been corrected; but they were ignored, glossed over, or hidden, and then became a significant cause for delays, rework, and cost overruns. Even worse was improperly completed work that was presented to the owner as complete. One approach to deal with more than one EPC is to have all contractors be fully responsible for payment of the LDs because that motivates them to work together effectively. Efforts need to be undertaken to make sure there is effective communication between partners. This is especially important when there are business or cultural differences between companies.

The EPC-M (with M for management) arrangement provides an alternative to the standard EPC contract where the seams between scopes are managed by one entity. To effectively have multiple parties, the scope seams need to be carefully managed. This approach becomes more feasible as the technologies mature.

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Another approach that has been used successfully is for the owner to manage the project, contracting scope to various engineering and construction companies. This approach works best for companies that own and operate power projects, especially if they have the technical personnel who are experienced with CSP technology and the resources to support the project. Often, experienced O&M staff can be used to supervise engineering and construction contractors and can play an active role or even lead the commissioning of the plant.

2.4 Development Topics

2.4.1 Site Selection

Based on feedback from participants, it appears that insufficient consideration went into the siting of many CSP projects. As a result, many projects took longer to construct, cost more, required more O&M budget, and, in many cases, performed below expectations.

Site selection is important and has a big impact on cost. Too often, sites are selected for solar resource, and not enough consideration is given to other aspects, such as remoteness, site topography, labor supply, access to transmission, roads and rails, access to water and gas pipelines or alternative fuel source for freeze protection, and environmental or permitting aspects. Many sites are selected by developers who do not have a good ability to assess the actual costs implications of selecting one site over another.

In addition, sources of potential health and safety risks on the construction sites need to be considered. These include location, weather, nature (plants and animals), the physical layout of the site, equipment, and hazardous materials. In addition, it is important to consider the local human behavior and attitude, country culture, and local political situation at the site. Actual conflicts with nomads and gypsies have occurred at CSP plant construction sites, which led to threats to site personnel and resulted in additional expenses for settlement of conflicts.

Best Practices

- Consider implications and logistics of selection of remote sites. The costs of mobilizing construction crews, transportation of equipment, maintaining qualified O&M staff, and access to service providers becomes much more difficult and costly for remote sites. Most remote projects appear to have significantly underestimated the cost of being remote.

- Environmental considerations for design and permitting of projects need to be adequately considered in site selection. The HTF used in trough plants must be taken into consideration and has resulted in some unexpected issues for some plants due to fugitive emissions. It is important to make sure that equipment supplied supports permit requirements.

- It is important to consider the health and safety implications of the design and HTF selection for plant staff, the public, and emergency responders, as well.

- Be sure to consider grading and drainage costs. Several plants have had significant cost increases related to designing the plant to protect from flooding. In some cases, plants have had significant costs due to actual flooding at the site. In this consideration, soil

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strength and presence of subterranean rock structures can significantly impact cost estimates.

- In addition, geotechnical considerations impact cost estimates for heavily loaded foundations such as for the salt tanks as well as for potential collector-field foundation excavations.

- It is always best to validate satellite-based solar resource data with ground-based measurements. Local topography, microclimate effects, and local aerosols can result in significantly different solar resources at a site compared to satellite data. Additionally, the resource measured over small time steps can have a significant impact on the actual performance of the plant compared to a TMY dataset.

- It is worth noting that if it is difficult to maintain clean instruments for ground-based measurements, it will likely also be difficult to keep mirrors clean at the plant.

- For central receiver plants, it is very important to consider whether the visual impact of the tower needs to be considered. In more populated regions, the visual impact of light on the tower and receiver should be considered and potentially be mitigated through design or location of the plant. But care should be used to minimize glint and glare from the heliostats, as well.

- It is important to consider all potential health and safety risks at a potential site. These include location, weather, nature (plants and animals), the physical layout of the site, equipment, and hazardous materials. In addition, it is important to consider the local human behavior and attitude, country culture, and local political situation at the site. Site security requirements must be considered.

- For water-cooled plants, the water quality may change over time. Care is needed when selecting the site as well as the water source and how it will evolve with pumping.

2.4.2 Environmental and Permitting

Environmental and permitting issues can have a significant impact on cost and schedule of plants.

Most of the feedback on environmental and permitting issues came from plants in the United States. In meeting with participants from the new U.S. plants built after 2005, it was clear that environmental and permitting issues have become much more complex than they were for the original SEGS plants. As a result, many projects appear to have been unprepared for the cost and schedule impacts that occurred. All the recent CSP projects built in the United States were financed through the U.S. DOE loan guarantee program. As a result, they were generally subject to more federal government regulation and oversight than might otherwise have been required. In addition, many of the recent plants were built in California. California has many special permitting requirements that can result in additional impacts on construction costs and schedule. Plants built in locations such as California may require union labor construction, which has implications on cost and schedule with more restrictive work rules than non-union labor. Building plants just across the border in Nevada, Arizona, or even Mexico and selling power into

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California can greatly reduce the cost and complexity of permitting a CSP plant. Several of the recent CSP projects in the United States were built on land owned by the U.S. government, whereas others were built on privately owned land. It can significantly simplify permitting of projects if they are built on private land, especially if the land has been previously disturbed, e.g., used for agricultural or other purposes. One project built in California on U.S. government land, required 150 biologists on site at one point to monitor the construction progress. This project spent about 4% of the total investment cost of the plant for environmental mitigation alone. Once again, it is important to consider these issues when selecting a CSP site. In total, these factors may have resulted in a 10% to 20% increase in cost for some projects.

One key environmental concern at central receiver projects in the United States was the potential hazard of concentrated sunlight to avian species. Both commercial tower plants in the United States received negative press about this issue. Although it seems likely that much of the information reported was significantly exaggerated in some cases, the issue is a real concern. Work has been conducted by Sandia National Laboratories, NREL, and others in collaboration with industry to evaluate the issues and impacts and to identify solutions. The main issue appears to be the high-flux zones that occur in the air space around the standby aimpoints when heliostats are operating at standby and not focusing light on the receiver. By spreading out the standby aiming strategy, the peak fluxes have been dramatically reduced in these plants, bringing flux levels down to the point where they do not appear to be dangerous to avian species. As a result of these flux-spreading approaches, avian mortality at these sites has been shown to be far less of a concern.

In addition to the high-flux zones, some avian deaths have occurred due to birds flying into mirrors and building structures. Design of plants should consider approaches to minimize impact dangers for birds. It may be possible to incorporate design features that make mirrors more visible to birds. Some projects have left native vegetation in place. This allows the plants to stabilize soil movement and minimize dust deposition on the mirrors. However, vegetation may provide habitat and potentially food sources for both birds and their prey, resulting in more potential for avian issues. Additionally, vegetation may need to be maintained to avoid interference with heliostat operation. On the other hand, maintaining a sterile field under the heliostats (i.e., no vegetation) requires herbicides, which are treated as hazardous substances in some regulatory regimes or an ongoing O&M expense to physically remove the weeds.

Best Practices

- Be very aware of the increased permitting burden due to environmental and other constraints. It is important to understand the regulatory burdens and account for these in the planning and scheduling.

- Carefully assess a proposed plant site to consider cultural, environmental, and permitting issues that will be required.

- The flight paths to military and civilian airports and military bases must be considered by central receiver plant developers. The height of the tower in a flight path is not usually a concern. Standard aircraft warning lights are usually sufficient. But the effect of glint and glare from an operating receiver on pilots' vision may become a permitting issue.

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- In the United States, consider building plants on private land. The use of U.S. government or state land may have implications that can result in significant delays and increased cost for CSP plants.

- Carefully consider the potential for environmental wildlife impacts. Tortoises and other desert species may have a significant impact on permitting, schedule, and labor requirements. For central receiver projects, special consideration should be given to potential avian impacts. Consider implementing design and operational strategies to mitigate avian impacts.

- Historical and cultural considerations enter into permitting, as well. Political sensitivity may be heightened on or near lands that were historically used by native peoples. It is prudent to interact early in studies with tribal leaders to preclude delays in public hearings and with permitting authorities.

2.4.3 Solar Resource Assessment

Solar resource assessment is quite important to project development because CSP plants are usually large investments and the estimation of the DNI solar resource is one of the biggest sources of uncertainty related to power yield.[4-5] There have been notable cases where the initial DNI estimates for a project site have been significantly different than the actual data measured at the site after a plant has been built. This is both in terms of the total annual resource at the site and in terms of the seasonal resource distribution. The presence of intermittent clouds is also one of the major issues that has negatively impacted performance of many plants. Hourly resource assessment totals do not typically capture this effect.

The costs for detailed solar and meteorological assessments of a site are very small compared to potential impact on performance. It is currently the practice in CSP development that the developer(s) select a qualified firm to provide a TMY recommendation with sufficient backup of its reliability. However, the wind energy practice is to ask for at least two independent assessments. If the main results of these two are within uncertainty ranges, they may be trusted for use. If they do not agree, the practice in wind is to ask for a third expert opinion. An even better approach—available from the solar resource industry—is to do high-quality bankable solar resource assessments that combine multiple independent satellite datasets with ground-based measurements to create the most reliable best-estimate. Data on inter-annual fluctuations should be part of the assessment.

The solar resource data must be at a granularity to capture how the plant will operate. Short-term drops in DNI can shut down a central receiver plant, and the data source needs to be able to capture this. Many projects have made their annual performance forecasts based on hourly DNI data. This approach typically does not accurately account for the transient behavior of the solar field and power plant, especially for short-term cloud transients. Also, wind gusts are not captured in the TMY data, which could result in stowing the solar field, significantly changing

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[4] Personal communication with Dr. Richard Meyers, CTO, Suntrace GmbH, Hamburg, Germany
[5] Personal contacts with Dr. Manajit Sengupta (NREL), Dr. Richard Perez (SUNY), Dr. Frank Vignola (Univ. of Oregon)

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the output of a plant compared to the solar resource alone. It is best if time resolutions of 5, 10, or 15 minutes can be provided. For central receiver plants, the spatial distribution of the solar resource has an important impact on operation and plant performance. This needs to be considered when modeling. Potentially higher time-resolution data are required as a result.

Significant advances have been made in satellite DNI data. Satellite data can be provided for most potential sites and can often provide 10 to 20 years of historical data. But satellite data rely on models that need aerosol optical depth and often are available only on an hourly basis. If satellite data are used, they should be calibrated with one or more years of ground-based measurement data; this process helps with better estimating aerosol optical depth and any local microclimate effects. The ground-based data should be used to create a finer time-increment resolution, as well.

There is some concern that only using TMY data for performance assessment is not a good approach for estimating the P50 performance or for use as a basis for the overall plant design. The design should consider the full range of solar resource and meteorological conditions at the plant site. If possible, 10 or 20 years of data should be modeled to estimate the P50 performance level, rather than using a TMY solar resource year.

It is worth noting that most data are either point-source or area-averaged data that do not capture the dynamic spatial variation in solar resource at the site due to intermittent clouds. This can be important for clear technical understanding of the implications on equipment, such as the dynamic variation on flux on different parts of the receiver in a central receiver plant.

It appears that climate change may be affecting solar resource at many locations. When evaluating the solar resource at a site, trends should be considered during the last 10 or 15 years.

Best Practices

- If 10 or more years of high-quality ground-based solar resource data are not available for a site, then satellite data that has been calibrated with one or more years of ground-based measurements should be used to estimate the solar resource at the site.

- P50 performance for financing should be statistically calculated from 10 or 20 years of modeled performance rather than from a single P50 TMY solar resource year.

- Performance forecasts should be made with sub-hourly data. For parabolic trough plants, 5- to 15-minute data should be considered. For central receiver projects, a minimum of 10-minute data should be considered, and potentially as fine as 1-minute data should be used to fully understand the expected performance of the plant. For central receiver plants, the spatial distribution of the solar resource will be important for understanding the operational implications for the receiver.

- To account for the impact of wind, it is recommended that both the peak and average wind speeds for any time step be included in the meteorological datasets that will be used for performance assessment.

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- One central receiver plant that used PV-powered heliostats has used the PV power to estimate the instantaneous solar resource incident on that heliostat. This allows a spatial estimate of the solar resource, which allows a more accurate estimate of the solar flux reaching the receiver at any given point in time.

2.4.4 Performance Model

All CSP projects rely on performance models to determine the expected performance for calculating the performance guarantee. Typically, the EPC provides the performance model used for the guarantee. The performance model is reviewed by the owner and its consultants and, if appropriate, by the LE before accepting it. The owner and its IE may also use performance models for EPC contractors bidding.

Many of these models are "black-box" models, where the actual model code and assumptions are not viewable, and the models have not been independently validated. An effort was made to compare different performance models in 2011 by SolarPACES.[6] Nine parabolic trough models were compared. A difference of 33% was seen between the highest- and lowest-performing models on a sunny summer day. Models that claimed to have been validated against actual plant data were within ±6% of each other. The effort highlights the variation in models and did not validate the models against actual plant data, which is even more difficult. To address this issue, SolarPACES developed "Guidelines for Bankable STE Yield Assessment" to develop standardizing guidelines for performance models.[7] This is a good first step for standardizing performance models for CSP plants. However, it is best if models can be validated against actual plant data for plant configurations similar to and of similar size to the plant configuration that is being modeled.

Many of the models evaluated are empirical in nature, which model energy flows and do not actually model the physical processes in the plant. Of special concern with this type of model is its inability to model the transient behavior of plants. As a result, the predicted daily operation profile of the model may vary significantly from the actual expected operation of the plant. As markets move to more time-dependent delivery structures, it is essential that the performance models accurately predict the temporal behavior of the plant.

Many projects use these empirical guarantee performance models with hourly TMY solar resource datasets to forecast the predicted annual performance of projects for financing purposes. Experience has shown that these forecasts are often not very accurate at estimating the actual performance of these plants, especially if the actual hourly output of the plant is important (for time-of-day pricing or peak-period power-generation forecasting). It becomes important to have more physical-based models that can better simulate the transient nature of the plant and account for start-up times of various equipment in the plant. Typically, finer-resolution solar resource data (time steps smaller than hourly) are needed to capture the transient behavior. It is also best to model the plant over multiple years of data to get a feeling for inter- and intra-annual

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[6] Kolb, G. "Trough Model Benchmarking," Presentation at SolarPACES, Granada, September 2011.
[7] Hirsch, T., Dersch, J., Fluri, T., Garcia-Barberena, J., Giuliano, S., Hustig-Diethelm, F., Meyer, R., Schmidt, N., Seitz, M., Yildiz, E., 2017. (b) SolarPACES Guideline for Bankable STE Yield Assessment (IEA Technical Report No. Version 2017), (c) Report of SolarPACES. IEA Technology Collaboration Programme on Solar Power and Chemical Energy Systems (SolarPACES).

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variability of the plant. TMY solar datasets should generally not be used for estimating P50 annual performance. It is better to simulate the P50 performance level by simulating 10 to 20 years of performance and statistically estimating the P50 performance. The P50 calculated this way will likely be lower than the TMY performance estimates, but more reflective of what should be seen.

The time-step resolution of the solar resource and meteorological data needs to align with the actual operation of the plant. Short-term low DNI or wind gusts need to be included. Hourly resolution data are much too granular. Perhaps 5- to 15-minute resolution data are adequate for general performance modeling; but potentially, 1-minute data are needed to identify transient solar conditions. Plants often shut down based on 3-second wind gusts. If the performance guarantee model does not capture this, then there is a mismatch between what the owner expects and what the EPC guarantees.

It is best if ground measurements are taken at the actual plant site. Satellite-based solar data may not account for local aerosols or microclimate type effects of small cloud build-up, or the intra-hourly variability of the solar resource due to cloud transients. These types of issues have had important implications on the actual performance seen for many operating CSP plants.

The performance model is often used to determine the guaranteed performance during the 3-year FAT. When there are shortfalls in the actual performance, there is a need to be able to identify the cause, specifically whether or not it is the responsibility of the EPC. Most current models are too simplistic and inaccurate to be used in this manner; however, they are used anyway. Future projects should make sure the performance model is designed to be used to evaluate performance losses. EPC contracts should include the procedure for how the performance model will be used to distinguish responsibility for shortfalls in performance.

The industry needs independently validated performance models that can be used for performance guarantees and for evaluating the operational performance of the plant. They should be transparent in that the specific code and assumptions used in the model should be viewable.

Most performance models use a single solar resource datapoint for the solar resource at the site for any given time. New techniques are being developed that allow for a more spatial measurement of solar resource over the plant. Performance models need to be adapted to consider better spatial and temporal resource data.

Best Practices

- The performance model should be a part of the EPC contract. If that cannot be the case—because the performance model will be created later during the implementation of the project—then the EPC contract shall define calculation methodologies, conditions, inputs, and outputs for the performance model, including corrections needed to be considered for the calculations.

- The performance model should be designed to be able to evaluate guarantees in the EPC contract. This performance model shall be used for evaluation of all types of performance guarantees of the plant including the guarantees for Initial Acceptance Certificate, Final Acceptance Certificate, and for O&M monitoring and analyzing the plant's performance

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over the project's life. The model could also be used for generating performance forecasts for the grid operator.

- The performance model used for performance forecasts and guarantees should be independently validated for projects of similar size and design and have been demonstrated to accurately model the temporal and transient behavior of the plants.

- Performance simulations should use solar resource and wind data in time-step increments that align with the actual operation of the plant. The models need to be able to account for short-term clouds (low DNI) and wind gusts. Weather data should include both the average wind speed over the time-step interval and the peak 3-second wind gust. Performance models should be able to use these data to reflect how the actual plant will be operated. If the performance model does not capture this, then there is a mismatch between what the owner expects and what the EPC guarantee covers.

- P50 performance estimates used for financial calculations should be based on multiple years of simulated performance and not only a single-year TMY dataset.

- The industry should consider developing a performance test code for how the performance model should be used for the FAT.

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3 Project Execution

This section describes the stages of project execution by the EPC contractor and related topics. The stages of the EPC activity and subsequent plant testing are design/engineering, procurement, construction, commissioning, preliminary acceptance, performance demonstration, final acceptance, and operation.

The EPC contractor is responsible for designing and building the plant to comply with the EPC contract (including the OTS) and providing a wrap-around guarantee to the owner that the plant will meet the guaranteed output in the financial model. The EPC must design the plant and procure the components and services needed to build it. The EPC is also responsible for quality control throughout these phases for the successful commissioning of the plant as well as handing it over to the owner while retaining responsibility to direct the operation by the O&M company. This section starts with a discussion of quality assurance and quality control as steps to be applied through all phases of project execution.

3.1 Quality Assurance / Quality Control

QA and quality control QC are intertwined in a successful application. QA establishes the methods to achieve stated acceptance criteria to be used to assure high quality in the planning and execution of a CSP plant. QC, on the other hand, establishes the specific practices and entities to implement the QA objectives through measurement and testing. In essence, QA defines the strategic procedures that dictate the required quality, whereas QC develops the tactical procedures and then performs the planned inspections that fulfill the specified quality. Stated differently, QA aims to prevent poor execution or mistakes, whereas QC aims to validate and document the successful accomplishment of tasks or to identify and remedy them, if needed. QC is also tasked with preserving documentation showing validating inspections that establish that the specified quality has been achieved.

The process begins with the owner and its OE establishing the criteria to which the project is to be built and operated. These criteria begin by invoking compliance with specific sections of national and international codes and standards. Additional technical criteria are added to achieve specific requirements of the process design. These criteria are documented in the OTS and made a formal part of the EPC contract and the contract with the O&M contractor. The EPC contractor uses these criteria to formulate the QA procedures and define for the QC department the compliance procedures and acceptance criteria for each discipline and activity. Compliance with these plans is required in each discipline. Examples are given below for each major EPC activity.

However, a cautionary note is important here. In projects with a vertical integration structure and a short-term exit strategy for the equity, quality assurance and quality control—including acceptance tests that will trigger the release of bank money—may adversely change the priorities between sufficient quality and lowest possible cost.

Engineering

There are criteria in engineering to ensure that drawings, specifications, and calculations are reviewed by proper authority and that documentation of design, design changes, and the final "as-built" configurations of the plant are properly recorded and archived for later retrieval.

In some turnkey projects, the validation of engineering work and the documentation of completed work is glossed over. In the best projects, the documentation of appropriate design reviews, design changes, and as-built configurations is explicitly invoked in the OTS and in the EPC contract and is audited by QA and QC personnel.

Procurement and Manufacturing

A design can be perfect "on paper," but if not manufactured correctly, it can result in operational issues. That is, errors in the manufacturing phase may well result in problems during operation.

Components of poor quality cannot be the basis of a high-quality plant. Frequently, poorly fabricated components are nevertheless used because of pressures in cost or time schedules. An upcoming termination deadline of the plant installation should not be the cause of using poor components; indeed, it would not be if proper inspections are performed, starting in the design and supplier evaluation period of the plant.

The EPC should use its own representatives in the factory for critical components, e.g., the solar receiver, pumps, and heat exchangers, and the OE should provide appropriate oversight.

Problems have even arisen where the same equipment from the same supplier was manufactured at different locations with differing quality and suitability. Proper QC could avoid such issues. For critical equipment, inspections prior to shipment from the factory are required.

Construction

In construction, physical activities such as welding will have non-destructive testing requirements. The performance of construction-validating activities such as testing concrete samples to ensure the design strength has been achieved; hydrostatic pressure tests and electrical continuity tests must be performed in accordance with specified criteria; and documentation must be properly executed and preserved. In some cases, the owners have also imposed formal witnessing requirements for critical construction processes such as the installation of heat-tracing and insulation systems on critical high-temperature piping.

Usually, steel structures of the solar mirror concentrators are assembled in a workshop on site. Assembly faults can occur because of limited human and technical resources at remote areas and tight time schedules. Good QC principles, used and established in other industries, should be applied in the production of solar concentrators. Well-suited measurement systems are available in the market to check the geometrical quality of concentrator structure with and without installed mirrors. Such systems should be used at least for regular checks if testing of all units is not feasible.

The QC oversight must deal with all equipment and systems in the plant. Inadequate supervision, inspection, and monitoring by the EPC and OE have been known to fail to identify construction issues until they have been repeated many times and become expensive and time consuming to correct.

Further, inadequate QC during construction results in longer punch lists and contentious relationships because issues are left to provisional acceptance if they could have been headed off

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earlier in the construction process. It has been observed that this is a significant and pervasive issue caused by insufficient appreciation of the importance of QC.

Commissioning

Commissioning activities must comply with component and system acceptance criteria, and they include that the transfer of custody is documented responsibly and formally. The QC activities in commissioning must involve several key engineering disciplines with sufficient experience to carry out their duties and ensure readiness to turn over the plant to O&M.

It is often during commissioning that operators learn that field redesign has occurred and that the plant does not actually match the issued drawings. QC staff should alert the OE as well as the EPC QA that "red-line drawings" and documentation of as-built configurations need to be issued to the operators.

Operation and Maintenance

QC during operation of the plant is an essential element of O&M given the many requirements for good maintenance and operation. The OE or other owner-designated entities must verify that good QC practices are in place during O&M.

During the operational phase of the plant, operators must comply with specified limits on operation such as:

- thermal ramp rates at turbine generator start-up;
- minimum temperature requirements in central receiver receivers before introducing liquid salt HTFs;
- mandatory central receiver drain and cool-down procedures; and
- maximum flux levels on the receiver.

The owners, with help from the OE and sometimes the LTA, are involved in reviewing and approving the details of the QA plan as well as, in some critical cases, the QC procedures. The QC teams or OE in each discipline (that is, in engineering, procurement, construction, commissioning, and operation) should carry out the steps required by these plans to achieve comprehensive testing of equipment and systems.

The importance of well-executed QA/QC in all phases of the development, design, procurement, construction, commissioning, and operation of a CSP power plant cannot be overstated. Proper attention to QA/QC from the onset of project development will help reduce future costs, decrease unavailability, and increase performance. QA/QC oversight must be carried out at several levels as a project develops by the owner, EPC management, and O&M supervision. Thus, the IE contract, OE contract, EPC contract, and O&M contract must be detailed and explicit in defining the roles of those entities.

The commissioning phase is particularly crucial because it is the final major milestone before the initial AC and then COD. At that point, all equipment and systems of the plant have been

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selected, designed, procured, installed, and commissioned to achieve the goals of the CSP plant. Proper QC is necessary to both—to observe whether a system and its interfaces are correct and to ensure that no damage is inflicted on plant components and systems during the commissioning process and/or by inappropriate operation of the plant at the stage of turnover to O&M. During this period, the EPC and OE have considerable crucial responsibilities for QC oversight.

3.1.1 Participant Feedback on QC

Several specific concerns of CSP participants on QC issues are the following:

Execution

Poor execution can result due to many reasons including owners not signing off on specific items that are part of the EPC wrap turnkey model.

It has been noted that wrap projects sometimes encourage contractors to cut corners. EPC contracts should formally invoke an audit and, in some cases, full review requirements of the QA /QC plans and test results, as specified in the OTS. This is especially necessary because it can be difficult for the OE team to properly observe and oversee QC issues in a turnkey EPC project. Furthermore, the role/power of the owner is often diminished during construction, which is a fundamental drawback of "strong" EPC contracts.

The EPC QC team should report at the top level of the local organization whose work they are reviewing as well as to the corporate QA manager. Staff employees should be well-trained, with the proper code certifications for the inspections in their scope.

Many companies have different approaches to QC. Uniform compliance is best achieved when the requirements are stated in the OTS and made part of the EPC and O&M contracts. One expert source recommends that QC requirements need to be a stipulation in an Annex of the EPC contract(s).

The scope of the QC team is defined by the QA plan as discussed above. The QC team is not authorized to inspect and opine on issues not included in the QC plan. For example, QC may be tasked with inspecting construction weld quality, but not whether an alternative design or different codes and standards should be used.

The documentation of proper compliance or deficient results are always the basis for financial penalty payments between parties at the final negotiation and close-out of the project.

Staffing and Supervision

The EPC is ultimately responsible for the QC, the extent of which is defined in the EPC contract and OTS. In general, it is typically the role of the EPC to staff and carry out the QC activities conducted as part of the EPC scope. The OE should ensure QC is being performed to these agreements and industry standards. The owner should have a supervision team present and also provide supervision to the EPC work and deliveries. Many participants have indicated the importance of having some O&M staff involvement in the QC activity in the construction, commissioning, and turnover phases. Lack of their presence can have a significant impact on availability during subsequent plant operation. Likely, the owner's team representatives including engineers, subject-matter experts, and key O&M personnel would support the owner's QC supervising during engineering, construction, and commissioning.

It is recommended to involve the owner (if appropriate, the OE) to witness the FAT of main components to ensure the clarity of the EPC contract and to bring evidence for payments related to the manufactured subject.

Commissioning

The commissioning is a very important phase in the life cycle of the implementation.

In this phase, the systems shall be filled with the working fluids, testing started, demonstrated operation of units and entire plant completed, and all the requirements for initial acceptance satisfied. The O&M company should be fully trained prior to the end of commissioning and shall operate the plant for the performance testing and reliability runs.

Commissioning is contractually assumed under the conditions of a good facility design, proper choice of equipment, and appropriate construction works, leading up to a plant sufficient to achieve the contracted performance and guarantees.

However, in reality, the design may be of inadequate quality, construction delayed, and early operation insufficient. The owner and the EPC contractor may put pressure on the commissioning team to begin the plant operation as quickly as possible, forcing them to minimize their duties list, verifications, tests, equipment adjustments and proper operation procedures. Under such conditions, the commissioning team can face problems when all the processes are not clearly structured, detailed planning is not finished, and procedures for each and every one of the tests and adjustments are not prepared.

Automatic systems control per the design are of particular importance for safe start-up. Too often, in order to complete the commissioning as soon as possible, some or many of the systems, subsystems, and equipment that were designed to be controlled automatically are left in manual control; the result is that various control levels, temperatures, pressures, flows, heat tracing, and more are operated in manual mode when LCs have all the necessary equipment to operate automatically. This is a mistake too commonly observed, which increases the pressure on the O&M staff to properly operate the plant.

Among many other problems that challenge the commissioning is insufficient time for system and entire-plant optimization. This is typically done during the FAT.

Best Practices

From the issues discussed above, all of which are keys to good QA/QC, several stand out as particularly important and worth emphasis:

- The owner and the EPC must engage sufficient and experienced staff to carry out the QC needs in all aspects of the plant development and operation. Properly done, this can be an extensive requirement given the needs during EPC and turnover to O&M.

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- All key components should be tested either in the fabrication line at the suppliers and proved by a proper testing documentation, or in a clearly defined incoming inspection at the power-plant site.

- Top-down system-level requirements may best be dealt with through comprehensive QA design reviews with EPC to identify problems before construction.

- There should be review and agreement, or approval, by the owner on key equipment.

- It is particularly important to avoid flaws in repetitive steps that would affect many components if not caught—e.g., heliostat-drive calibration or control problems that will show up in every unit, or problems with thermocouples.

- Senior engineering and O&M staff[8] should be assigned to provide QC oversight in all the phases of the EPC responsibilities—in particular, during commissioning and the turnover to O&M control.

- For major equipment, it is advisable that the owner or its OE oversee manufacturing, transport, testing, commissioning, and operation to stay within the manufacturer's specifications.

- Project standards should include well-prepared QC documents covering methodologies and acceptance criteria for equipment, systems, and interfaces. Interface and QA/QC documents need to be understood by all parties.

- Strong QC is particularly important in major equipment and systems. For example, although it is more mature technology, the balance-of-plant steam systems often provide the most impact on plant availability. Failure to achieve design objectives has usually been due to inadequate QC during the design, the manufacturing, and particularly, in the operation of the equipment. As a result, manufacturers' thermal ramp-rate specifications and water-chemistry requirements are not able to be adhered to during operation. Of particular concern are large heat exchangers with thick tubesheets and severe duty. This problem could also be caused by poor system design or poor control software.

- To check the installation work, early and frequent tests should be integrated into the solar-field assembly schedule (both troughs and heliostats). In particular, the first installations of parabolic trough collectors or heliostats should be tested to (1) check whether the technology matches the results of the prototype tests and proves that no basic design or assembly errors have been made between prototype tests and final product; and (2) check whether the installation teams use the installation and alignment procedures correctly or whether these procedures may have to be adapted to account for local aspects that were not foreseen.

[8] Either professionally degreed or subject matter experts (see Nomenclature)

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- The OE and EPC should develop and implement QC procedures to be carried out on completed equipment and systems. In this early stage of the assembly work, faults in material and processes can be fixed quickly and at relatively low costs, without severely challenging the termination deadline. But at a later stage, this may not be the case.

- QC is a crucial ingredient in commissioning, and subsequently, in O&M. Like any thermal power plant, a CSP plant is complex given the many subsystems involved; and it is in the early stages that those subsystems must be checked out and fully operated as subsystem units or as part of a major integrated system for the first time. Diligent QC is absolutely necessary to ensure that all systems are operated according to specifications and proper procedures.

3.2 Engineering

There are typically three levels of project engineering (note these are sometimes referred to by different names):

Conceptual engineering is an initial design document including operation capacities, screening of the process technologies, site selection, and high-level process and basic documentations including process flow diagram, piping and instrument diagrams, and overall plant layouts. Conceptual engineering also includes electrical single-line drawings, preliminary control loops and logics, and a preliminary equipment location drawing, initial versions of the specifications for the major equipment, preliminary hourly performances over the TMY, capital-cost estimate, O&M cost estimate, and levelized cost of energy estimate. The feasibility study is usually completed in time for proposals to RFPs for the EPC contractor. If the RFP has delivery guarantees, then engineering and a firm EPC price may be needed at this point or a way for the owner to mitigate price changes from bid until all contracts are signed and financing closed.

Preliminary engineering builds on the conceptual design and includes nominally complete versions of the piping and instrument diagrams and the major equipment specifications. In some cases, information from manufacturers will be needed to complete the engineering drawings. Potential equipment suppliers are contacted during this phase to obtain estimated costs and engineering data needed to complete the engineering drawings. Work continues on the electric single-line diagrams, control-loop and logic diagrams, principal piping layouts, primary structures and foundations, and project schedule. Refinements have been developed for the performance model, capital cost, and O&M cost. With the additional engineering detail, contingencies on the cost estimates can be reduced to values in the range of 15%–20%. Discussions have begun with potential lending institutions and equity providers, and information has started to flow to the local, state, and federal permitting agencies. Depending on the funding available, purchase orders for as many of the long-lead equipment items as possible have been placed. The equipment with the longest procurement lead times have included the turbine-generator, station transformers, solar receiver, large steam-generator vessels, and, in some cases, control-room equipment. The conceptual design is also based on the OTS and RFP supplied as the EPC contractor's technical proposal to, in part, support project financing.

Detailed engineering prepared by the EPC contractor typically continues starting after the NTP and should be largely complete shortly after construction begins, but is not fully complete until

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"as built" documentation is completed after the successful initial testing of the entire CSP plant. Items developed include the piping and instrument diagrams, equipment specifications, electric single-line diagrams, structure and foundation drawings, piping isometric drawings, piping specifications, valve specifications, instrument lists, programming of the control system, commissioning, and testing procedures. Purchase orders have been placed for all of the equipment, and information from the suppliers has been incorporated in the plant design. Contingencies on the performance and cost estimates has been reduced to values in the range of 5%–10% once the initial detailed engineering has been completed. However, once construction begins and continuing through commissioning, field engineers document design changes with "red-line" markups of issued systems and, in particular, physical designs. A current set of "as-built" drawings are maintained and distributed, particularly to the operating staff.

3.2.1 Constructability

Constructability is the optimum use of construction knowledge and experience in planning, design, procurement, and erection. Maximum benefit occurs when individuals with construction knowledge and experience are involved at the very beginning of a project. See Figure 3-1.

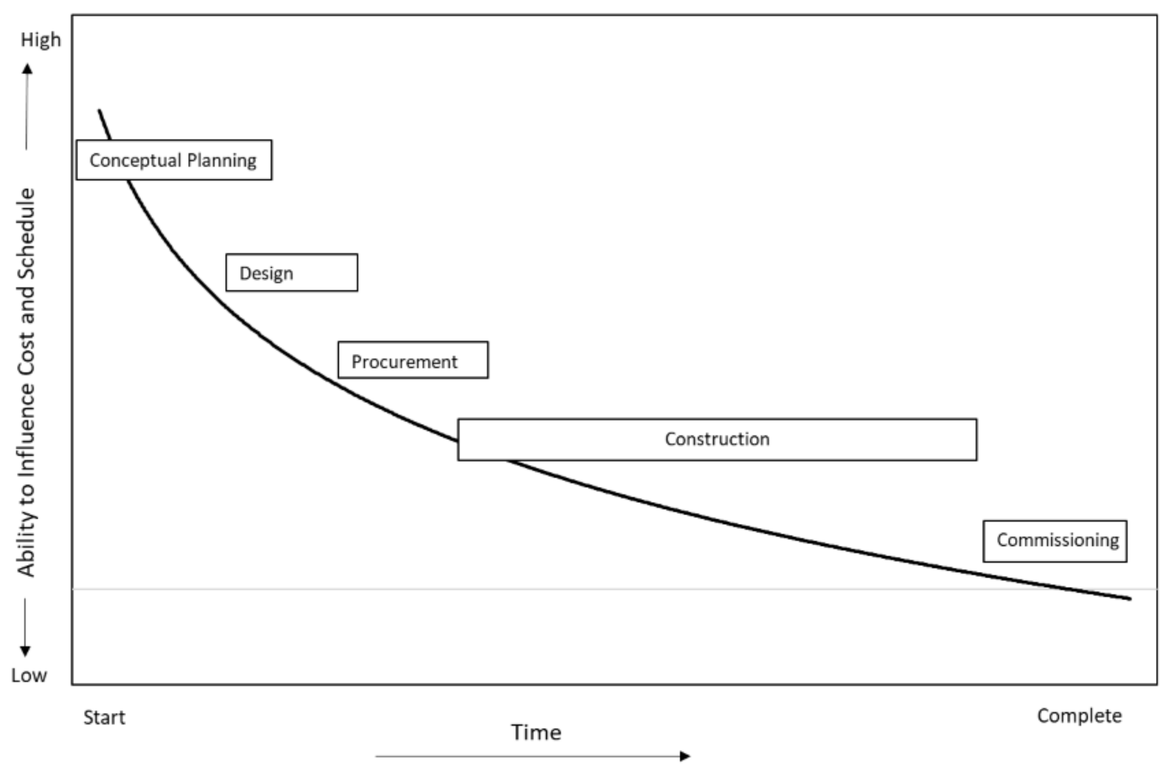

Figure 3-1. Constructability
Source: Construction Industry Institute

Basic constructability concepts applicable to the *conceptual planning* phase of the project include:

- Constructability programs are an integral part of project execution
- Project planning actively involves construction knowledge and experience

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- Early construction involvement is essential is developing the contracting strategy
- Project schedule is driven by commissioning and construction
- Basic design approach considers construction methods
- Site layout promotes efficient construction and optimum operation and maintenance.

Basic constructability concepts applicable to the *design and procurement* phase of the project include:

- Design and procurement schedules are construction-driven
- Construction schedule is commissioning-driven
- Designs are configured to enable efficient construction
- Design elements are standardized
- Construction efficiency is considered in development of specifications
- Module and pre-assemble designs are developed to facilitate fabrication, transport, and erection
- Designs consider facilitating construction under adverse weather conditions.

Project execution tends to separate functions. Design tends to place emphasis on minimizing costs. Construction focuses on minimizing field costs. Constructability integrates these parts and is a powerful tool for owners. A constructability program must:

- Clearly communicate senior management's commitment to the program
- Encourage teamwork, creativity, new ideas, and new approaches
- Start constructability as soon as possible
- Emphasize total project integration, not optimization of individual parts
- Establish a constructability procedure
- Evaluate progress and results.

One of the keys to avoid schedule compression is to implement change management during engineering. A strict change-management procedure requires review and approval of changes by affected managers. The procedure needs to include an analysis of the potential impact of the change on cost and schedule. This will reduce the tendency for individuals or groups to make changes that are for convenience but are not necessary.

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Basic constructability concepts applied during the *engineering* phase of the project include:

- Review of engineering design concepts prior to detailed design by experienced construction individuals. This will help to ensure design approaches that promote the most expeditious and cost-effective methods of construction.

- Packaging for transportation. Consider the dimensional limitations of common transportation modes when designing and specifying components to minimize the need for special transportation and handling.

- Design freeze. A design freeze date should be a scheduled milestone date. This forces activity planning and implementation targeting this date. If engineering is late, then construction typically starts work on partial design. This leads to inefficiency during construction and potential for changes.

- Schedule should be developed based on the logic to complete the project. Startup activities establish the need dates for construction. Construction establishes the need date for procurement and engineering.

Key constructability concepts during *construction work management* include:

- Area coordinators. Establish staff positions whose function is to coordinate and expedite work in their area. They have no direct construction responsibilities, but will assist all personnel in their area by resolving interface problems, coordinating use of space, resolving material delivery difficulties, coordinating use of lifting equipment, and validating reported commodities.

- Change management. A structured system should be used with the objective of reducing time loss and extra cost associated with changes. The system should consider the following: (a) each change should be challenged as to its need, particularly if it involves rework, (b) each change should be reviewed to determine if another more cost- and time-effective approach can be implemented, and (c) timing should be reviewed to determine its least impact on the schedule.

- Tool management. Lack of tools is a common cause of craft delay. A strong tool-control program is required. The program provides for continuous monitoring of tool issues, returns, and inventories to prevent shortages.

3.2.2 Importance of a Qualified and Experienced Engineering Team

CSP technology is a relatively new emerging technology. In addition, CSP projects are relatively complex projects. As a result, the quality, timeliness, and completeness of the engineering is critically important to the success of the project. Engineering has to be driven to deliver complete and quality engineering packages to procurement, construction, and commissioning teams. In some cases, subcontracts with engineering companies with no previous CSP experience and/or with little or no local or in-country experience have been signed, making it more likely to result in design, cost, and/or schedule issues. Sometimes, the engineering company is forced to adopt riskier designs to reduce procurement and/or construction costs. However, the cost associated

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with the potential decrease of plant availability during the lifetime of the plant are often not balanced against those cost reductions.

3.2.3 Design Reviews

In the case of an inadequate process, design problems can cause serious problems for the EPC contractor and the owner. An efficient design review can potentially identify and resolve such problems.

Because of the scale and complexity of CSP plants, it is very difficult and expensive to monitor and/or provide adequate oversight of the EPC activity during the engineering and construction phases. Inadequate design/engineering results in problems all the way through the project and into operation. Therefore, productive and effective top-down system-level design reviews performed by OE are needed to catch problems before construction.

Hazards and Operability (HAZOP) / Layers of Protection Analysis (LOPA) reviews need to be mandatory and made part of the project milestones. These reviews identify all HAZOP problems before the design is finalized via a meaningful design review. Some projects have undergone a HAZOP study to identify and resolve risks during design, but this largely depends on the experience of the EPC contractor. If the EPC is disregarding design and/or the manufacturer's operational requirements, then a design review may be needed, among other corrective actions.

Best Practices

- Projects need design review strategies most commonly used to confirm that the EPC contract—licensing, permitting, and regulatory—requirements have been met to include codes and standards applied for a specific project.
- The owner shall ensure that the design review will be performed for all key technical disciplines by highly qualified and motivated personnel. Usually, the contract with OE shall be clear on this need.
- The design review can also be conducted to determine whether the proposed design will be fully functional and, after functioning successfully, can be adequately maintained properly.
- It is necessary that the design review take place at an early stage of the project to avoid purchasing and erecting equipment and/or undertaking construction works that might be rejected or adjusted in the review cycle.
- The design review shall be a part of effective project management, ensuring enough time for the review and implementing changes into the revisions of detailed engineering documents.
- Strong, thorough, and disciplined top-down owner-managed engineering reviews are necessary at various stages during design.

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- The owner should include personnel experienced with actual plant operation (e.g., plant operators) who can provide realistic scenarios and necessities to be considered in the design.

- The owner should ensure that a study is performed to model the steam generators and have a heat-exchanger expert review that design prior to acceptance.

3.2.4 Timing of Engineering

Initiating procurement or construction ahead of engineering can and does cause significant problems.

Engineering needs to be substantially completed ahead of procurement and have an iterative interaction with manufacturers. Performing design, procurement, and construction simultaneously creates problems. Construction should not outrun the design completion. For example, it is obviously not good practice to have the electrical crews on the construction site waiting for designs of the cable trays. A fully integrated model that shows where engineering happens—and if it is in a procurement package or ahead of it—mitigates this and allows for engineering to be just-in-time.

Best Practices

- One approach is to complete as much engineering and practical design review before procurement or construction begins. However, this is likely not practical and extends the execution period, resulting in higher costs and longer development cycles. A robust schedule that is adhered to may be the best option.

- Another approach is to develop and use a standard design with related specifications and lock in the design ahead of procurement and construction. Replicating a prior plant design is useful, if possible. Such a baseline design that gets adapted for site-specific issues is best to control the timing of execution and to manage costs from project to project.

- Predefined design and documentation for a plant of the same size and capacity can save a tremendous amount to time and money to provide detailed engineering documents submission for review in the EPC contract.

3.2.5 Design for Transients, Start-Up, and Shut-Down

The EPC usually develops a process design that is based on meeting design-point requirements, such as receiver output at noon on the equinox. Equipment damage due to low-cycle fatigue will very likely be the long-term result if there is insufficient experience or thought given to transients or to the daily start-up and shut-down of the equipment to keep within the vendor limits on rate of temperature change and number of thermal cycles.

The tower receiver, turbine-generator, and major heat exchangers are representative of equipment requiring close attention. For example, the SGS heat-exchanger requires, per the manufacturer, defined limits on start-up temperature ramp, rate of temperature change, thermal shock (difference in metal temperature and fluid temperature), minimum flow rate, solar flux levels, and the permissible number of thermal cycles. Pump vendors will define limits on minimum flow rate, maximum flow rate, and minimum pump speed.

The heat-exchanger and pump sizes are typically selected to satisfy both the plant design-point requirements and the vendor limits. However, during start-up and shut-down, the equipment necessarily operates at load conditions between 1% and the vendor's lower limit (perhaps 20%). For heat exchangers, these conditions can result in nonuniform flow distributions, which can produce nonuniform temperature distributions. The latter can result in stress distributions that compromise the low-cycle fatigue life. For pumps, operating at very low flow rates can lead to vibrations, high bearing wear, and flow oscillations.

Best Practices

- Carefully design operating modes that best suit the PPA requirement and smooth operation, and select equipment to ensure high efficiency and long equipment life.

- Due to daily cycling, design and equipment selection need to account for short start-up capabilities.

- Plants need to be designed for transients, part loads, and full operation (e.g., start-ups and shut-downs, cloud transients, higher irradiation as maximal design point) as well as the 100% design point. Many experienced engineers build capacity margin into each component to allow for the plant to respond to off-design-point operation and recovery from excursions.

- In addition to the daily start-up and shut-down cycles, the EPC must also understand cyclic and transition load levels, operational modes caused by actual weather, equipment failure, units or plant trips, dispatch requirements that may occur during the operating day, and the design along with the DCS controls/logic need to consider these factors to maintain rates of temperature change within equipment limits.

- It is incumbent on the EPC to provide the means to protect the equipment during low flow conditions. These include split-range flow-control valves, pump minimum-flow recirculation loops, and heat-exchanger recirculation pumps and valves.

3.2.6 Plant Layout

The design of CSP plants is a complex team effort involving different disciplines of engineering: process, mechanical, piping, electrical, instrumentation, controls, civil, logistics for construction and for the assembly of reflectors at the site and their erection in the solar field.

The objective of CSP plant layout is to design and construct the plant in a cost-effective manner that will meet the process requirements and OTS and will operate in a safe, reliable manner considering the O&M requirements for a long-term PPA.

Equipment is often packed into a vertical configuration that is cramped and limits equipment access.

In a trough plant, there is usually no good rationale—other than perhaps lower initial cost—for the tendency to go vertical with equipment when there is so much horizontal space available. In a central receiver plant, the closest heliostats are the most-efficient heliostats. There is a tradeoff here, because keeping the heliostats close to the tower tends to limit the space available for the power-block equipment.

Cost goes up with a cubic function for the structure to support a vertical orientation. Strong consideration should be given to this tradeoff. A general conclusion is that land cost in places where CSP is relevant is more likely lower than going vertical.

Best Practices

- The detail engineering requires considerable management and coordination skills by the EPC contractor, vendors, O&M contractor, and the owner/OE.
- Consider equipment layout to maximize accessibility for ease of O&M while taking the plant performance into account.
- The CSP plant layout must consider in the design the following:
    - Constructability
    - Maintainability
    - Operability
    - Satisfying environmental requirements
    - Minimizing costs.
- Several key main aspects should be considered during development of the layout, such as:
    - Effective drainage systems for rainwater for the solar field and the power block
    - Process requirements
    - Economy of material and transportation
    - Erection and construction requirements
    - Safety requirements
    - Operation and maintenance requirements
    - Grouping of similar equipment for easier maintenance and safety wherever possible.

3.3 Procurement

3.3.1 EPC Contracts

It is common for the EPC to divide the system into components and subsystems and bid them out to get the lowest acceptable price. But this can be problematic if not well thought out and

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executed. For example, in a power tower plant, the receiver, heliostats, and control system must work as an integrated system. These are typically different companies, so there must be considerable effort put into achieving a seamless coordination. No one equipment manufacturer has all of the required capabilities—whether for the solar technology or for the power block and balance of plant.

One option to be considered is to negotiate between the owner and EPC contractor for owner payment of more expensive equipment designated by the owner, and/or specify approved equipment from a qualified vendors/equipment list where it is important to the owner.

The EPCs seek to obtain the needed components and/or subsystems at the lowest possible cost by encouraging competition. However, it is difficult to make the contracts between the EPC and the technology providers complete enough that they can anticipate and address all the issues that may arise between the parties. As EPCs divide up systems into smaller elements to encourage competition, there is a need to manage the resulting interactions between the component providers while satisfying the OTS as agreed upon between the owner and EPC. To do that, detailed contracting and acceptance criteria are needed. And where there are co-EPCs, this need becomes even more important.

The interface between the EPC and its subcontractors and component suppliers needs to be carefully defined. For example, the interface between the provider of the receiver and of the heliostats and of the control system must be carefully defined so they work as designed and as required.

If the responsibilities and interrelationships between EPC and technology providers (subcontractors) are inadequately defined in their contracts, this often leads to conflicts. The contracts between the EPC and the technology providers are well written in a legal sense, but they may lack sufficient technical specificity. If technical data are not specified explicitly, then questions of interpretation are likely to arise (e.g., reflectance may not be specified with its beam spread; reference temperatures may not be given). Including experienced technical expertise with the legal team would likely improve these contracts. Lack of clearly delineated contract requirements for equipment redundancy or critical performance requirements can result in equipment or performance deficiencies.

The above observations clearly suggest that the EPC should avoid buying lower-cost equipment because it is likely to not meet the initial or long-term guaranteed performance requirements of the plant. A common error is to purchase equipment with a capacity that just barely meets the specified volume, pressure, or electrical rating. Experienced EPCs always purchase equipment with some amount of margin, knowing that in the real world such margin is often needed. It is best to pay a little more for more robust equipment, and also, to select technology providers and service providers with a proven track record in CSP plants.

Best Practices

- Develop comprehensive contracts with the technology providers that clarify the responsibilities and interrelationships between them and the EPC, engaging knowledgeable engineers to add the needed specificity.

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- Include detailed acceptance criteria, redundancy, and critical performance requirements in contracts between the EPC and the technology providers.

- Typically missing in CSP design is an overall reliability model that statistically shows all components in series and parallel with their failure rates, mean time between failure, and mean time to repair calculated to show how the availability of the plant will be high. The EPC contract focuses on energy production, but availability is a subset of that, and availability is also related to maintainability. With such a model embedded into the EPC contract, one could then identify an amount of maintenance required by design.

- Consider the tradeoff between cost and reliability and between cost and expertise when awarding contracts.

- Use proven technology-specific equipment as much as possible.

- Ensure that selected technology and expertise providers have the necessary experience and capabilities to provide the needed services.

- The EPC contractor shall establish a strong vendor management team because vendors need clear guidance, evaluation, communication, and feedback. This team shall set up a strong vendor management program and clear expectations that lead to achieving the value and performance outcomes needed from vendor contracts. This management team shall also ensure that the owner/OE will be provided with sufficient documents for FAT and to ensure more transparency for handover procedures, allowing briefings and explanations at the early stage of the project.

- Consider EPC operation of the plant with the O&M provider's personnel for the guarantee period and then having a "COD" of that team and that it be turned over when the plant and the team are functional as a unit.

3.3.2 Procurement Program

This subsection is based only on the information provided by participants, so it does not address all of the issues related to the procurement program.

Procurement programs often do not allow enough time or remuneration for the completion of front-end engineering studies. Major equipment purchased under schedule and/or cost pressure often results in sub-optimal purchases that fail to meet the performance requirements.

Procurement strategies under which selecting a preferred contractor in time for detailed planning activities should be considered. Very strict procurement programs with significant cost pressure often stress the project to such an extent that agreements are entered into without proper foresight, possibly followed by dire consequences. Cultural issues and/or mutual understanding can play a significant part in this dynamic.

During project implementation, deviations from desired performance in terms of time, cost, and quality usually take place. Procurement can contribute considerably to such deviations as well as to reduce or possibly eliminate them. However, EPC contractors use different ways to deal with

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project deviations and EPC contract's requirements—namely, strategy modifications, process modifications, and combined modifications. Strategies modifications focus on time, cost, and quality, but also aim to reduce the number of suppliers for a certain item to reduce the complexity and management costs by both the EPC contractor and vendors, and finally, to reduce the bargaining power.

The high impact of procurement on project performance is just as evident in many CSP projects with regard to time: consider the long-delivery item, whose purchasing process might begin even before the actual start of the project with LNTP.

Best Practices

- The overall procurement program structure should be reviewed to allow time and payment for front-end engineering studies and to avoid bargaining pressures that could result in rushed and inappropriate purchases.

- Schedule sufficient time for the owner to review and sign off on major equipment purchases as well as long-term agreement for commodities supplied (e.g., liquid nitrogen, water treatment plant chemicals).

- Logistics and supply-chain management shall consider the challenge of a remote construction site where the EPC contractor shall choose from between *multimodal* transport that is characterized by essentially separate movements involving different modes, or *intermodal* transport that involves integrated shipments across modes including the same billing system.

3.3.3 Logistics

Getting material, equipment, services, and skilled personnel on site can be very difficult. Adequate supply and retention of qualified labor in remote areas is often challenging. Logistics is the process of strategically managing the procurement, movement, and storage of materials, equipment, parts, and finished inventory through the organizations involved in the project and their marketing channels in such a way that their profitability is maximized through the cost-effective fulfilment of purchase orders.

The scope of logistics spans the organizations—from the management of shipping from factories to the site of the materials, equipment, and parts.

In many CSP projects, the logistics and supply-chain planning underestimated the challenges caused by remote sites and the enormous need of material and equipment, which led to delays and additional costs. There tends to be a lack of motivated and experienced people in remote areas, and it is necessary to pay a premium to get skilled workers there for long relocation.

On some projects, a high turnover rate has been an issue because workers will leave for better-paying jobs in more attractive locations, or for higher pay at nearby construction sites. Substantial issues have been associated with accessing skilled staff in remote regions, and it has been more difficult and more expensive to incentivize staff for plants in those locations. Mobilization of highly specialized technicians to remote areas without advance notice is difficult, and it requires planning and time if delays are to be avoided. In some remote areas,

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EPCs have had to build man-camps and temporary housing facilities for both construction workers and for plant operators.

Legal arrangements, including working visas, must be carefully planned.

Methods to handle equipment repairs should be planned in advance. It can be difficult and time consuming to get a qualified manufacturer's experts to remote locations, and it takes time for them to arrive. Consideration should be given to do many repairs on site with the O&M team. Although it is not possible to maintain a staff who has experts in each piece of equipment or computer system, it may be necessary to have the O&M team members, with skills in several basic disciplines and crafts, multitask to be ready when needed, e.g., to weld a broken part or reprogram programmable logic controllers (PLCs). Strong consideration should be given to long-term service agreements for most major equipment. Having a power park might help justify having the needed onsite skills. Availability of qualified welders is an almost universal issue in remote locations.

In particular, O&M strength in qualified crafts—such as electricians, and instrumentation and control (I&C) and DCS specialists—is particularly important.

Delays in the first-time implementation of CSP projects in a specific region or country have been reduced in some projects once good-quality suppliers were identified and used in subsequent projects. This coincides with the country's industry development and the ability of the region to supply the needed skills.

It is often challenging for an EPC to work with subcontractors who may be used to working on a fixed price with a budget for each item, or if the subcontractors were more expensive than modeled and if they had to pay prevailing wages. It is important to predict labor hours accurately.

There have been cases of needing to get a large piece of equipment (e.g., a construction crane) moved internationally. EPC use of foreign equipment manufacturers for non-major components (e.g., actuator, valves, heaters, pumps) that are not reasonably supported, maintained, or distributed in-country can become a logistical nightmare for the O&M.

Best Practices

- Consider the new rules of competition. In today's marketplace, the order-winning criteria are more likely to be service-based than only product-based.

- Ensure the review of the functionality, performance, and technical specification of the detail engineering, the offer, and purchase order.

- Consider the availability, support, and commitment provided by the vendor to the EPC contractor and the owner (e.g., supervision of erection, spare parts, support during performance testing and maintenance).

- Ensure appropriate storing and handling of delivered products at the site (e.g., avoid corrosion, damages, sand and dirt getting into the products).

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- Ensure services such as catering, accommodation, first aid, and other appropriate services needed at remote site.

- Problems in getting equipment and skilled people to remote sites can be diminished by adequate logistical planning and careful due diligence by the vendor in procurement.

- Complete an upfront survey of local critical skills and local suppliers needed for construction and operation of the plant before NTP.

- Consider extension of the qualified vendors list to cover more location-specific maintainability.

- Be prepared to pay a considerable cost premium to get skilled workers to move to, and stay in, remote areas.

- Be aware of local labor regulations and allow time to negotiate sub-subcontracts.

- Have in-place service agreements with major equipment suppliers.

- If the location of the plant is remote, consider performing most repairs on site by OEM-trained O&M staff; and if possible, consider clustering plants in a power park to share repair equipment and capabilities.

- To the extent possible, specify equipment/skids to be built in factories/shops rather than building onsite. This can facilitate construction and improve quality.

- The procurement or logistical plan must make provision for moving imported equipment through customs.

- Projects with large or heavy equipment components may need a "Transport" plan describing which rails and roads have the capability to handle heavy-haul components. This plan needs to consider the allowable height restrictions of overpasses and utility wires.

3.4 Construction

This subsection is based only on the information provided by participants, so it does not address all of the issues related to the construction.

3.4.1 Construction Safety, Packages, and Site Appearance

Poor-quality construction packages and tolerance of poor housekeeping will create problems. Safety is of utmost importance, and it should be a high consideration in all planned activities.

The EPC needs to be held accountable for providing construction packages that are organized and complete. Contractually, this needs to be done and handled through the QC process that identifies, reviews, and approves every package with milestone payments. O&M should provide input. Rather than self-perform the majority of the construction or pass the risk on the EPC contract to others, many EPC companies subcontract with several smaller companies, some with little or no CSP experience.

Work packages can be assembled to complete work in all disciplines for a specific room or area. This is often used when a general contractor is responsible for all crafts. On the other hand, if the work is being executed by subcontractors, each responsible for a different craft (e.g., piping, electrical cable and conduit, boilermaker and millwright work), then assembling packages based on (first) craft and (second) system or area makes more sense.

Poor housekeeping raises concerns beyond cosmetic appearance. Tolerance of poor housekeeping leads to lack of worker respect for the job site, which, in turn, leads to carelessness, vandalism, damaged equipment, and improper installation, which results in early failure. Examples of poor housekeeping include:

- Construction materials lying on walkways, stairs, and platforms. This can include opened cans of weld rods, boxes of electrical conduit fittings, or boxes of paper towels.

- Lunch refuse, cans and bottles, and other debris not properly disposed of.

- Construction scraps such as weld rods, insulation scraps, small auxiliary steel scraps, small pipe and conduit scraps, dunnage and shipping materials lying in the plant.

- Large construction materials such as cable spools, large pipe supports, and boxes of insulation staged in the plant for long periods of time before use.

- Unrepaired damage such as torn pipe sheathing and insulation or broken electrical components.

Poor housekeeping can also lead to difficulty in controlling the quality of the work. For example, if cans of weld rods are left open and uncontrolled in the work area, then casual or negligent welders can just grab the nearest rod instead of the rod with the correct metallurgical and welding specification.

Lessons learned in the CSP projects have shown delays over time deadlines, estimated budget overruns, and issues with construction work quality.

There are many reasons for construction deficiencies in issues such as lack of clarity, unclear objectives, unclear focus, lack of concentration on the goals, and lack of business focus combined with a lack of qualified managers for CSP plants. Insufficient project management puts the employees in a situation that they often are simply unaware of the goals of the project they are working on. Generally, the construction management is forced to concentrate on the budget and the deadlines instead of pursuing efficiency. Sticking to the budget and managing on time is without doubt important; but finding the most efficient way that will save both time and money, if not present, can lead to lower quality.

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Best Practices

- Establish a flow of communication with everyone involved in the construction process—EPC, OE, vendors, subcontractors, supervising authorities, design team, and commissioning team. This transparency will make the process smoother and will reduce unawareness, mismanagement, and potential claims whenever a problem arises.

- EPC packages must be organized and complete, with input from O&M and reviewed by the owner or OE in the EPC contract negotiation.

- It is important to focus on the details—small details, which are easily overlooked, may cause significant issues later.

3.4.2 Construction Schedule

Balancing construction schedule versus price is a challenge for the EPC.

Owners need to have confidence that the construction schedule is realistic for a quality plant. And owners (as well as lenders) need to have a way to track progress and verify the schedule accurately with approved action plans to get back on schedule, if needed.

The EPC needs to have a professional scheduler and an agreed-upon software that is used with proper links between activities and concurrent execution.

Bidding a 3-year construction EPC contract versus a 2-year construction EPC contract has cost implications. Obviously, the cost of project overheads and interest expense are affected by project duration. Experience with similar projects is necessary to make realistic schedules. The construction schedule must consider the potential for extended equipment lead times, logistical issues, and the possibility and impact of receiving damaged or inadequate equipment and the time needed to fix or replace it. A second plant at the same site by the same developer could be built faster and perhaps operate better because vendors know what is needed and can better comply with specifications and local conditions. (This would favor a vertically integrated EPC developer because all the learning can stay in one place; however, learning from EPC to EPC in multiple teaming arrangements is a more difficult undertaking.)

Best Practices

- During the project strategy phase, it is necessary to properly define the organization of the project implementation, project objectives, and various performance measures. Scheduling should comprehensively identify and examine in detail the economic, technological, legal, geographical, and social aspects of the project.

- The base time schedule is fixed in the EPC contract, and the included milestones are under penalties. Therefore, the EPC contractor should set out events and activities tasks in accordance with a set of precedence constraints that consider variations in availability of resources including manpower, machinery, equipment, material, energy, space, and finance. A well-known type of precedence relationship in CSP projects is the finish-to-start relation with zero time-lag (that is, an activity can only start as soon as all of its predecessor activities have finished). Any delay in a predecessor activity has an influence on delaying the entire unit. EPC contractors aim to meet the base contractual time

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schedule; and to avoid any penalties, the construction can reduce the quality of the unfinished unit at the time of commissioning, which can lead to unit material damages or underperformance.

- The EPC and the owner need to discuss construction schedules and, based on experience, agree on a realistic one. Similarly, the owner's technical experts and/or the OE should review the schedule prior to approval.

- If a delay in the project is obvious and the OE and LE cannot identify the reasons, then closely examine construction critical path(s) and develop construction sequences that prioritize minimizing the long sequences with careful attention to prerequisite tasks. Most prerequisite tasks are easy to spot. For example, underground utility corridors and many foundations must be in place before completing the remaining foundations, building structural steel, or pulling conduit. Careful evaluation must be given to such issues, perhaps by an independent technical auditor.

- Certain plant systems are useful during the completion of the construction tasks. The EPC must decide if the permanent plant services (or portions of those systems) can be installed and operated ahead of the commissioning schedule or not. If not, the constructor must install temporary services such as construction power, service air, service water, sanitary sewers, and public address systems.

- Construction and commissioning time schedules are generally tight, in which technological risks and technological uncertainty have been underestimated and a probability of difficulties and unit/system failures are not fully considered.

- Extra time needed for procurement of material and equipment due to a remote site and local culture shall be properly investigated and sufficiently estimated for the planning.

3.4.3 Construction Delays

This subsection includes a few participants observations on the causes of construction delays that have been experienced in CSP plants, then discusses the contractual remedies, e.g., liquidated damages, and how they should be managed.

To avoid construction delays, much needs to be done before the NTP is issued. The preliminary engineering should be well advanced, the construction team established, the OE engaged, the water and power supply needs and plans established early in development, the required granting of permits achieved or in process, and certain requirements of the PPA and interconnection agreement met.

Projects with experienced participants should be able to complete construction and start-up on time or within several months of the scheduled COD. However, delays are likely to occur if the owner sets a construction schedule that is too tight and the EPC agrees to this under pressure from the owner and/or the financing entity. EPCs generally have a 24- to 30-month period from the NTP to COD. A number of CSP plants do not achieve COD in the scheduled time, with the delays typically three months or longer. Delays are generally decreased for EPCs involved with

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prior similar projects. Significant delays have been experienced by plants in developing countries, or with new players with little track record, or when involving different cultures.

Work practices vary by location around the world and in an increasingly global market. Construction schedules can be influenced by EPC prior experience, availability of qualified labor, and many other issues. To minimize delays, all factors such as those noted below that could significantly impact schedules should be identified prior to issuance of the EPC contract. Careful considerations should be given to all these issues by the EPC and owner.

Some examples of delays related to specific functions of the EPC are the following:

<u>External delays that might be caused by the owner, authorities, laws, and other factors</u>

- Delay in obtaining permits from authorities.
- Effect of social and cultural factors on labor, vendors, and site conditions.
- Changes in government regulations and laws.
- Lack of utilities cooperation at site (e.g., providers of water, electricity, communications such as telephone and internet).
- Delay in providing services from off-takers (such as wastewater, hazardous material, power).
- Accidents during construction.
- Fluctuations in costs and currency.
- Delay in performing final inspection and certification by owner and authorities.
- *Force majeure* such as war, revolution, riot, strike, or earthquake.

<u>Delays caused by the owner or OE</u>

- Change orders by owner during construction.
- Underestimation of time for completion.
- Slow decision making.
- Poor communication and coordination by owner/EO with EPC contractor and authorities.
- Late in review and approving detail design documents by owner/OE.
- Delay in finance and payments by owner.

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- Poor supervision (QC).
- Delays in inspection and testing.

Engineering – Delays can ensue if the EPC contractor subcontracts the bulk of the engineering and then commercial issues arise between the EPC general contractor and his or her subcontractors, such as contract disagreements or change of firms.

The main causes of delay can be summarized to the following topics:

- Misunderstanding of owner's requirements by design engineer.
- Mistakes and discrepancies in design documents, OTS, EPC contractor's detail design, and vendors' documentation).
- Usage of different terminology across the engineering, contractual documents, and site teams.
- Delays in producing design documents and their reviews.
- Unclear and inadequate details in drawing.
- Inadequate design-team experience (design teams designing conventional power plants usually underestimate the cyclicity of start-ups of CSP plants).
- Insufficient data collection and survey before design (soil and meteorological data).
- Delay in approving major changes in the scope of work by owner/OE.
- Poor communication/coordination between owner/OE, EPC contractor, and other parties.

Procurement – Experience and quality versus cost are major considerations in the procurement process. Equipment procurement may proceed generally as programmed, but delays may be caused if the EPC either did not anticipate or could not quickly adapt to the challenges of selecting and/or mobilizing suppliers for plants located in remote areas. Delays can also arise from the EPC's lack of experience in negotiating with potential subcontractors in an unfamiliar country. Commercial issues with subcontractors can result in slowdowns on site. Although easier said than done, EPCs should consider preference to vendors with good products and experience and then contract with them on future projects as a preferred supplier, because the vendors will get better with more opportunities.

Further cases of delays are late procurement of materials/equipment, escalation of material/equipment prices, and renegotiation of suppliers' contracts, changes in material types and specifications during construction, and finally, a delay in material delivery.

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Construction – Delays can be caused if the EPC lacks experience in managing local subcontractors or is not familiar with the regulatory relationships in the country in which it is working. The day-to-day supervision of construction and/or commissioning, as well as coordination of the work of multiple subcontractors in the same space, can be hampered by communication issues (both internally and with subcontractors), which can result in stand-downs in trying to resolve them. This can also result in extensive rework that further delays progress. A common cause of delay is the time lost between NTP and actual start of construction. If the NTP is issued too soon (pushed by financial or administrative reasons), then work usually progresses very slowly, dragging delays for the rest of the project.

Examples of some specific delays are those in blowing steam pipes and in the alignment of the turbines due to problems in dimension specifications. Other cases of delay can be in customs or labor issues at ports of entry. Access to project location may be problematic during construction. Local roads, traffic regulations, customs, and duties must all be considered. Roads may need to be upgraded or modified, and the impact of traffic flow on access roads should be considered.

A study[9] of six CSP plants noted that *force majeure* events, such as labor unrest or extreme weather events, caused most construction delays; only minor delays were due to supply-chain issues.

The typical LD clauses in commercial contracts based on achieving adequate performance or maintaining schedule may not be sufficient to induce EPC contractors to perform quality and timely work. Sometimes, unresolved claims pile up until a final settlement needs to be negotiated at the end of the project. A mechanism is needed to escalate disputes to a sufficiently high corporate and lender management level to resolve conflicts in a timely manner. Although delays are accounted for in EPC contracts, how they are managed and resolved is critical. In many cases, the contract language is sufficiently stringent with LD and delay penalties, but the administration of those provisions can be challenging. It is most important to avoid the situation where the owner relies on the penalty clauses and the growing penalties to induce action by the contractor and the contractor relies on growing delays to induce concession on the part of the owner.

LDs should cover schedule delays and not meeting performance, but quality is another issue. Quality is covered by warranty (typically 12–24 months) and extended warranty (typically 5–10 years) for specific equipment.

Solar-field warranty, covering a large number of similar components, might be covered by a serial defect provision. One observation is that if greater than a certain percentage of components fail—e.g., 10% of heliostat or trough components within 5 years—then the contractor should be required to prepare a plan to remedy the failure. And if root-cause analysis shows that the defect is from design or production error, then the components should be repaired or replaced.

[9] Source: Independent engineer participate in best-practices project.

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Best Practices

- Before NTP, the conceptual/basic engineering should be completed, the construction team established, the OE engaged, the water and power supply needs and plans completed, the required permits granted, and certain requirements of the PPA and interconnection agreement met. Although this seems reasonable, it could cost a few million dollars before financial closure. Using a standard design to reference conditions and adjusting from there could make this palatable.

- The owner and EPC contractor should set a realistic schedule that accounts for experience, location, and other critical factors.

- The EPC should try to work with preferred suppliers or experienced vendors and, as noted earlier, receive owner approval for the selected parties.

- The EPC should establish effective coordination mechanisms between itself and its many vendors.

- The EPC contract should define a dispute-resolution process that reflects the best interests of both parties and whereby delays are resolved as fast as possible and with minimal financial cost to the EPC and owner. As noted earlier, avoid the situation where the owner relies on the growing penalties alone to induce action by the contractor and the contractor relies on growing delays to induce concession on the part of the owner.

- Engagement of OEs by the owner is recommended to avoid—or, if not possible, to resolve—construction delays, and the OE's cost should be anticipated and included in the project budget.

- The EPC contractor's materials and equipment management shall make sure that the appropriate quality and quantity are selected, purchased, transported, delivered, and handled on site in a timely manner and at a reasonable cost.

- EPC contractors shall ensure effective material and equipment handling, which includes procurement, inventory, shop fabrication, and field servicing. This handling requires special attention for time-saving and cost reduction.

- With a highly qualified EPC contractor's management team, the owner should expect coordinated planning, evaluation of the quantities and requirements, sourcing, purchasing, transporting, storing, operation and maintenance of the equipment, minimizing the wastage, and optimizing the profitableness and saving of valuable time.

Other factors causing delays are:

- Unqualified workforce with insufficient training.

- Low productivity level or shortage of labor.

- Low productivity and efficiency of equipment.

- Equipment availability and failure issues.
- Low level of equipment and subsystem operator skills.
- Personal conflicts among employees and companies' managements.

3.4.4 Cost Overruns

The success of a CSP plant is defined by how well its performance supports the financial model in the loan agreement. Therefore, it is critically important that the plant's financial targets are met. To do this, cost overruns must be kept to a minimum.

Failure to meet financial targets because of poor plant availability can result from (1) cost-cutting by engineers, procurement demands, constructors, operators, and quality engineers, and/or (2) omitting necessary design calculations, and/or (3) not following normal construction practices, and/or (4) not understanding how to operate the plant safely and efficiently.

Cost overruns can usually be attributed to a lack of thorough planning and engineering by the EPC, which can be the result of time and cost pressures imposed on the EPC. There are many additional causes of cost overruns, with most overruns due to delays that end up causing labor to work more hours than planned.

For example, not accounting for building-code violations related to fire, lightning, and/or health or safety regulations require additional labor time and thus cause delays. This should be resolved by the engineering design criteria, which would result from a code study prior to contracting the EPC.

Labor strikes can also cause delays. Inadequate engineering that requires significant rework on civil aspects is also costly. Cost overruns have resulted from non-proper site and soil-condition assessments, inadequate analysis of access roads, water and sanitary transport and treatment, or new requirements.

Cost overruns also may be due to equipment failure and the associated delays. Some equipment warranties are for 5 years or longer, depending on the criticality of the equipment, whereas others are not for more than 2 years after delivery from the manufacturer. In many cases, the warranty expires before the equipment can be put into operation. The EPC may need to cover any additional or uncovered costs to fix or replace faulty equipment and related labor. However, the main point here is that such issues must be very clear in the EPC contract covering failures, extent of warranties, and responsible parties up to final acceptance.

Best Practices

- Completion of detailed engineering milestones as a major payment trigger will support the overall culture of increasing the capacity for planning and careful engineering, which should result in fewer cost overruns.
- The owner should be prepared to fully staff the O&M company with an adequate number of qualified people for an initial start-up period including the commissioning and, to a lesser extent, the engineering phases.

- Be sure the commissioning and O&M teams are properly trained before commissioning begins. In this regard, seconding the O&M staff to the constructor to operate those systems that have been completed early will give the O&M staff familiarity before final turnover. Expert O&M staff must fully understand how to start and operate the plant during commissioning and beyond.

- In most cases, the cost overrun in CSP projects is not only due to EPC contractor's claims but also because of a delay beyond the completion date specified in the EPC contract. To the owner, delay means loss of revenue through lack of power production and penalties. In some cases, to the EPC contractor, delay means higher overhead costs because of longer work period and LDs.

3.5 Commissioning

Project commissioning is the operational step after EPC. The commissioning process is the integrated application of a set of engineering techniques and procedures to check, inspect, and test every operational component of the project—from individual functions, such as instruments and equipment, up to more complex subsystems and systems. More importantly, commissioning includes operation of all plant systems, subsystems, and equipment over the full range of design conditions. In practice, some systems will be able to be commissioned before all construction is complete. The overriding aim in this process is to ensure that all components and systems of the power plant were selected, designed, engineered, installed, tested, operated, and maintained per the detailed plant engineering design to satisfy all plant operational requirements. After commissioning is complete, the plant is turned over to the operator/O&M team for operation. In current CSP plant development, this typically is the start of a multi-year performance warranty period during which the EPC is still responsible for the plant and oversees the operation by O&M.

The main goal of commissioning is to accomplish the safe and orderly handover of the unit by the EPC to the owner for normal operation by the O&M team, guaranteeing its operability in terms of performance, reliability, safety, and data traceability. Additionally, when executed in a planned and effective way, commissioning normally represents an essential factor for fulfilling schedule, costs, safety, performance, and other requirements prior to COD.

Oversight on the behalf of the owner during the commissioning process is typically carried out by the owner and OE, in coordination with the lender's technical advisor (LTA or LE) and with O&M specialists.

Notably, it has been suggested by some participants that commissioning by the EPC has not worked well for CSP plants. For example, commissioning by the O&M team based on procedures developed by EPC, reviewed and approved by the OE/O&M team, might work better. The punch list developed in commissioning needs to be generated and items repaired by the EPC.

Key elements of the commissioning process include, but are not limited to, the following:

- Oversee complete application of industry-accepted QA/QC procedures to all systems during commissioning prior to plant operation. This is a crucial step and should not be curtailed. All such procedures should be clearly defined in the EPC contract.

- Review and witness the supplier's/factory acceptance tests on main and predefined equipment carried out by the EPC during the procurement activity.

- Check the functioning and accuracy of instrumentation and other measurement devices.

- Where appropriate, perform or ensure the calibration of instrumentation and measurement devices.

- Check the functioning and scope of the DCS and other major plant control systems. The most successful commissioning teams have at least one member who is skilled in adjusting and reprogramming PLCs.

- Conduct functional performance and initial reliability tests of plant subsystems and systems.

- Ensure adherence in commissioning tests to all O&M standards and other requirements for units, such as the steam turbine, thermal storage, key pumps, and key heat exchangers.

- Operate the full plant in all appropriate stages, adhering to required limits on such operations as ramping speed at start-up and shut-down maximum and minimum temperatures, pressures, and solar-flux levels.

- The commissioning is an EPC responsibility carried out by a team under the EPC. But many participants advise that key members of the engineering and O&M teams should be included on the team for purposes of experience, knowledge, advice, training, and familiarity with all facets of plant operation.

- Oversight of the QA/QC carried out by the EPC during commissioning should be assigned by the owner to an OE, O&M specialists, and other designated qualified entity. This supervision entails considerable engineering activities because it requires assurance that the final plant design, including all equipment and systems, is capable of achieving the goals of the CSP plant. The owner or its OE and O&M specialists are responsible to verify testing and certify the acceptance for takeover of the entire plant. For example, it should include review of the commissioning plan, detailed inspections of construction and testing, performance oversight, and approval sign-off of all completed systems prior to owner acceptance. This supplements the QA/QC by the EPC itself.

- During the commissioning, the O&M contractor's team is trained by the EPC commissioning team for the operation of the plant.

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Scope of CSP Industry Feedback

Recommendations from major CSP industry participants regarding issues relevant to the commissioning activity are discussed next. This information includes input and recommendations from engineering, EPC, and IE firms during the course of the study by either response to questionnaires, direct contact via in-person meetings, or conferences via the web or phone. The inputs differ in areas of concern, cost, quality of major equipment, operational complexity, field experience, and other factors subject to individual project needs. The intent here is to provide credible advice over a gamut of alternatives.

Project developers, owners, and their contractors use several approaches to reach final plant configurations that offer credible, cost-effective designs that differ in configuration, quality, cost, and performance. The following recommendations, focused on commissioning the plant, derive from a wealth of experience in CSP development, engineering, and operation. They are provided to offer critical issues to be considered in the commissioning process.

Partial List of Commissioning Issues and Risks

Some general statements can be made regarding the activities carried out during commissioning. The following observations illustrate the nature of the issues and the risks involved. The observations are not purported to be universally accepted by the CSP industry; but they are meaningful in that they reflect important observations on practices by individual participants in this study.

- Experience shows that the quality of performance in commissioning will vary with the EPC team(s) carrying out this responsibility on a project. A concern—often expressed but not necessarily true and certainly not universal—is whether full and acceptable performance of this activity can be compromised if the EPC is pressured by the pending goal of provisional acceptance.

- It is critical that the EPC commissioning team and the subsequent O&M team have sufficient experienced and knowledgeable members in lead positions. With significant involvement during commissioning, O&M team members will gain operational familiarity and an element of responsibility for the plant that it will eventually be operating.

- During the commissioning period under EPC responsibility, poor practices in operating equipment and systems by the commissioning team or by assigned O&M staff can damage equipment prior to commercial plant operation. This can be a serious issue. For example, excessive ramp rates in the turbine, inadequate control due to design, or purposeful override of system protection can damage components such as the steam generator. Similarly, operating the receiver outside of the prescribed limits on flux levels can lead to equipment failure.

Best Practices

Several recommended practices stand out from the responses on commissioning from the industry participants—in particular, firms involved in independent engineering:

- Commissioning success varies with the competence and experience of the commissioning manager that reports within the EPC.

- Some participants argue that having the EPC perform its own commissioning can be problematic because the EPC may be under pressure to achieve provisional acceptance on schedule. One available safeguard to minimize potential issues is tight monitoring by the OE/owner to seek possibilities of improper operation, lack of procedural compliance, or poor engineering controls in place that make operations overly complex and potentially dangerous. Such difficulties can require extensive outages that impact COD or PPA commitments.

- During commissioning, the owner needs to be involved to ensure that the OE is doing its job, which is to ensure that the EPC is doing its job.

- An EPC team established for that purpose carries out commissioning, typically comprising very experienced personnel brought in by the EPC. It is strongly recommended that selected top-level staff from engineering and O&M be funded and integrated in the commissioning team—from its onset through turnover to O&M—and that the higher staff levels be degreed engineers or subject-matter experts in the disciplines necessary for success. Expertise in the areas of I&C, mechanical, and electrical should be included. Specifically, knowledgeable process engineers and DCS technicians with a deep understanding of automation and control need to be in place in commissioning within both the EPC and owner/operator teams.

- There may likely be a lack of experienced CSP plant operators. So, commissioning/O&M training is critically important and must be initiated early; yet, it is often an afterthought during EPC specification and contract creation negotiation. An effective and excellent practice is when an experienced owner/OE uses O&M personnel to monitor or participate in commissioning. It gains O&M familiarity with the plant, and the O&M has "skin in the game" for the plant that it will eventually be inheriting.

- Milestone payments should be tied to operational completion points that are analogous to turnover-packages documentation at handovers, with punch lists from construction to supervision.

- The owner/project company should assign sufficient funding and adequate participation of key staff from the OE and O&M teams during the entire commissioning phase.

- QA/QC – See Section 3.1. Extensive and thorough QA and QC are very important in commissioning, during which all systems are tested and operated for proper design, construction, and performance prior to turnover to O&M. Proper QC is necessary to both observe whether a system and its interfaces are correct and to ensure that no damage is inflicted on plant components and systems during the commissioning process and/or by inappropriate operation of the plant. The QC also documents the plant's specific performance and the completion of commissioning, system by system.

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- During commissioning, O&M training, and initial operation, sometimes the only way—or a shortcut—to bring the unit back to normal operation is to temporally bypass some equipment protections. Whether or not this initial equipment "break-in" phase may result in permanent damage to the equipment is a function of the input by all participants (owner OTS, EPC design, EPC equipment specifications, manufacturer quality/experience, commissioning, and O&M). Unfortunately, inadequate design and poor operation can result in permanent impacts on plant lifetime performance such as increased start-up time, increased trip-recovery time, lower efficiency, lower operational flexibility, reduced equipment life, and/or lower plant availability.

- The ability of the EPC to adequately account for all possible transient modes of operation and associated system/equipment behavior is a difficult but achievable objective. The design, heat-exchanger specifications, and DCS programming will govern whether equipment can be operated within limitations. Often, there is not enough consideration and/or experience given to these details during design, and this issue ends up being a commissioning/initial O&M phase activity that results in adjustments to DCS programming and O&M procedures.

- Detailed O&M procedures need to be developed prior to commissioning with cooperative input to the EPC from of all involved parties. Corrections or other modifications need to be available prior to COD. The OE and O&M team should review and ideally approve all O&M procedures documentation prepared by the EPC before operating the plant and be set up for all the usual responsibilities of operation with a well-trained, functioning crew.

- Some participants believe automation levels are far too underdeveloped and are often not in place at the point of COD. The best CSP plant design/control systems still do not allow for hands-off plant operation during these periods (nor should they be expected to at this stage). Thus, operator experience is more imperative than in typical thermal power plants.

- Correct water chemistry is a key area for plant operations; it is the responsibility of the commissioning team with oversight by the O&M team during commissioning.

- Contractual penalties have been known to tempt EPC companies to knowingly disregard some equipment safety practices and take some commissioning risks. In such cases, the oversight by QA/QC and the OE and LTAs can help an EPC recognize its obligations.

<u>Commissioning Team and Staffing Issues</u>

- Commissioning is always a key area of concern for all parties. An EPC with a well-organized commissioning team is required to achieve long-term reliability and short-term high early performance. EPC qualification/selection criteria should include experienced personnel with CSP background for all the main positions in engineering, construction, and commissioning phases.

- The commissioning team will be the first operators of the plant. Their knowledge and training will be crucial to the O&M team assigned to normal operation. Depending on the contractor, commissioning is sometimes poorly planned, and high flexibility is required

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from the parties involved. But once defined, commissioning roles tend to be clear and execution good. Personnel involved in commissioning should ideally be very experienced with previous commissioning work.

- The EPC contractor's commissioning team is responsible for and directs the commissioning activity. A strong commissioning team should include selected engineering and O&M staff. When commissioning is complete, the O&M team's mission is to carry out the plant O&M under the responsibility of the owner, but under the oversight of the EPC until final acceptance—that is, during the long-term guarantee performance testing period. The transition from commissioning to O&M is a critical step that can have significant impact on the plant lifetime. Some O&M teams have not been trained adequately to take over the plant by COD.[10] This transition requires an important manpower investment (commissioning team and O&M team working together) that may not be fully included in the EPC scope/cost.

- The commissioning team should ideally be experienced from participation in power-generation and CSP projects. Construction staff with experience on the specific project are typically integrated into the commissioning team. The commissioning manager should be on site at least one year before commissioning. Experienced commissioning staff should be part of the project engineering team to provide input to the schedule and establish turnover packages early in the project.

- At a minimum, a lead control room and field operator should be part of the O&M team during commissioning, working under EPC direction. The EPC team must include specialty-equipment technical advisors and, as noted earlier, subject-matter experts. After COD, the EPC team should be working under O&M team direction during the guarantee period.

Commissioning Turnover to O&M and Initial Operation

- Prior to the turnover to O&M, a robust commissioning program is needed to verify the design and construction prior to operation. Such a program should include a well-defined and solid turnover program for the stages from construction to commissioning to operations. Experienced EPCs and commissioning teams turn over custody and responsibility incrementally on a system-by-system basis. The O&M staff will typically operate these systems under the overall direction of the EPC contractor, who retains financial responsibility to demonstrate plant performance at final acceptance.

- Inadequate operational procedures sometimes inhibit start-up and commissioning activities by the EPC due to many non-standard operations. EPCs do not tend to be stringent in exercising procedures that are developed as contractual responsibility. Thus, procedures have not been fine-tuned for standard operation by O&M operators, and

[10] **Commercial Operation Date** or "COD": means, in relation to the Power Station, the date one day after the Procurer receives a Final Test Certificate of the Independent Engineer as per the provisions of clause 6.3.1; "Commissioning" or "Commissioned" with its grammatical variations means the Unit of the Power Station has passed the Commissioning Tests successfully.

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O&M ends up rewriting procedures. All of this still needs to be managed with the EPC during the guarantee period to avoid issues with the contract. In one operation, every change and every procedure made was sent for EPC review.

3.6 Performance Guarantee Testing and Warranty

At the end of the EPC construction and commissioning of the plant, the EPC contractor needs to demonstrate that the plant can operate and meet its minimum performance criteria. The types of performance testing, performance guarantees, and warranties used by CSP plants have varied significantly over the years and depend on the structure of the contracts and region where the project is in the world. We present one approach that is used by some of the more recent international projects and that appears to be becoming a standard approach.

3.6.1 Testing at the Completion of Construction and Commissioning

The plant typically has initial or preliminary acceptance tests that must be conducted and passed. Initial acceptance testing typically includes a demonstration of the capability and efficiency of the major systems in the plant: solar field, thermal energy storage, and power block. This testing is conducted by the EPC to demonstrate to the owner that the plant is ready to turn over to the O&M contractor for O&M and fulfill all EPC contractual obligation for being initially accepted by the owner.

Once initial acceptance has occurred, the plant is typically handed over to the owner, and simultaneously, the owner hands over the operation of the plant to the operator, who is then responsible for the O&M.

In some cases, the EPC can be in a hurry to turn over the plant to the O&M contractor, who is not fully ready to take over. Or the EPC wants to turn over a plant that is not fully ready to be operated in a normal manner. Frequently, the DCS system has not been fully completed. Often, the commissioning team has bypassed safeties in the control logic to get the plant to operate and has not fully resolved the issues; maybe the issues are included on the punch list. This provides additional challenges to the O&M personnel, who are more concerned with protecting equipment lifetime. One of the common issues appears to be incomplete DCS controls/logic, alarm management, and automation of certain systems of the plant.

Commercial Operation Testing

In addition, the PPA may require similar testing to be conducted for the plant to achieve its COD. The COD testing is intended for the project to demonstrate to the utility or off-taker that the plant is ready to go into normal operation. COD is the point at which the plant is considered in normal commercial operation under the PPA and often starts receiving full price for electricity produced. Sometimes, the testing requirement for IA and COD are not the same, so the dates for IA and COD do not necessarily coincide. Typically, this requires a 10- to 30-day reliability test of the plant. This requires the plant to demonstrate that it can operate normally for this period and generate the contractually defined power (say, greater than 80% of the design performance). The intent is to show that the plant can operate safely and in a reliable manner during this period; therefore, some EPC contracts define that no failure of any unit can occur.

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One participant noted that the acceptance tests have been stringent enough on trough plants and have been seen to work effectively and be a sufficient benchmark to identify EPC issues before handover. This participant had not seen enough comparable power-tower plants to identify or benchmark the tests. But the participant noted that some central receiver plants suffered issues during acceptance testing, which is resulting in more detailed and stringent acceptance tests being required for central receiver plants being developed and/or constructed.

Best Practices

- Allow for a provisional acceptance test that provides the EPC some financial payment, followed by a long-term test period of 1 year before final acceptance.
- Establish warranty test criteria that consider the key project-specific factors such as the CSP technology, location, and solar radiation.
- When available, use performance acceptance test protocols that have been established, such as PTC-46 and PTC-52 (under development), along with component test standards.
- However, even using such protocols, it would be necessary to incorporate not only referencing the protocol, but also, identifying how that would be used specifically, including the required instrumentation, starting conditions, and other factors.

3.6.2 Final Acceptance Test

Once the plant achieves IA, the plant may start its FAT. This is typically a 12-month or longer performance test where the actual plant performance must achieve some level of performance in relation to the EPC's performance model—often 100%. The EPC contractor provides guarantees on a plant that is operated and maintained by the O&M contractor. Hence, it is in the EPC contractor's best interest that the operator operates the plant properly. To facilitate that need, the EPC contractor may decide to keep a team onsite to monitor and assist the operator. A typical approach is that the O&M team is under direct supervision of the EPC during the FAT.

Best Practices

- Typically, a performance model is used to calculate the guaranteed performance of the plant during the FAT. It is important that the EPC contract clearly define which assumptions (if any) can be changed during the FAT.
  - Some EPC contracts allow for adjustments for issues outside of the EPC contractor's responsibility. It should be defined what this is intended to include, is it just a Force Majeure type clause to cover items clearly outside the contractor's responsibility, or does it include issues related to the O&M of the plant during the FAT.
  - If the plant will be operated by a third party, EPC contractor in theory should have built its performance guarantee around the assumption that a third party would be operating the plant. Alternatively, some assumptions such as mirror cleanliness may be adjusted to use actual values during the FAT.

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- If the performance model will be used to compare to actual performance on a daily basis, the model should be run on 5- to 10-minute resolution time steps during the FAT for trough technology, and potentially as small as 1-minute resolution data for tower plants. Solar data will need to be recorded on the time resolution. For finer resolution time steps, some spatial distribution of solar resource around the plant may be needed. Hourly time steps have been shown to not provide an accurate reflection of the operation of the plant during transient conditions.

- During the FAT, the solar monitoring instrumentation should be cleaned and checked for alignment at least once per day.

    - There should be at least two or three instruments measuring the DNI.

    - Multiple monitoring stations across the plant can help provide more spatial averaging of data.

    - Real time or frequent error checking of the data should be conducted to identify any issues with alignment or cleanliness of the instruments.

    - Many plants have pyranometers with shadow bands installed as backup to pyrheliometers for measuring DNI. These should be commissioned and maintained to allow them to be used as backups.

3.6.3 Performance Ramp-Up after IA/COD

In addition to the FAT, there is typically a performance ramp-up guarantee over the first few years of operation. The ramp-up will depend on the maturity of the technology, the experience of the EPC contractor, the maturity of the market in the country, the location of the plant, and the capability of the owner and operator. An example ramp-up scenario is that the plant must achieve 80% of the performance model output in year 1, 90% in year 2, and 100% in year 3. Similarly, it is typical for CSP plants to include a performance ramp-up period in the financial plan during the first few years of operation following initial acceptance.

Best Practices

- The EPC and the owner need to discuss ramp-up schedules and, based on experience, agree on what will be realistic.

- During the long ramp-up period, the roles and responsibilities of the EPC and the O&M company must be clearly defined and assigned.

3.6.4 Punchlist and Warranty Provisions

In addition to the FAT performance testing, once the plant achieves IA, the punch list is finalized, and the EPC contractor has some period of time to resolve issues on the punch list. Typically, the EPC will also offer an equipment warranty that lasts for a year or more after IA.

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4 Operation & Maintenance

It has become apparent through discussions among project participants that it is critical to have O&M involvement early on and integrated throughout the key stages of the project—starting with the design and continuing through construction, commissioning, and up to project turnover. This section describes the functions and best practices of the O&M team for these specific pre-operation services and for the later continuing O&M stage.

The O&M pre-operation services should first consider and develop a plan for specific O&M personnel during the different phases for this part of the project (design, construction, and commissioning) and the responsibilities for individuals during the different phases. Likewise, an O&M plan should be developed for the typical O&M stage that addresses the organizational plan, strategies, and goals for the project. In general, this plan should consider the organization structure and functional groups/roles; safety compliance, plant performance, annual budget; operational programs, maintenance programs, staff training, spare part and inventory control; and contractual, environmental, and regulatory compliance.

4.1 O&M Involvement During Design

O&M subject-matter experts (O&M SMEs) in plant operations and plant maintenance (power block, thermal energy storage, and solar field) were mentioned by participants as key personnel to review and contribute to design efforts of the project. This is important to avoid potential deficiencies in equipment protection; optimizing operations/start-ups; and ensuring safe and efficient equipment access and maintenance.

It is a critical design objective of the O&M SMEs and staff to focus on the quality of the key documentation to be delivered by the EPC (including but not limited to: process and instrumentation diagrams, functional descriptions, O&M procedures, and O&M manuals). This is because the O&M team will be the end user of such documentation.

Background

Several project participants emphasized the importance of O&M expertise and involvement during the design phase. It was noted that the design operating conditions, modes, and start-up times were not always obtainable and realistic, and that O&M expertise involvement would potentially alleviate these issues.

Lack of adequate control for temperature gradients and protecting equipment associated with transients, start-ups, and trips has been noted from project participants as a potentially significant availability impact, especially from the SGS being out of service. Participants have mentioned issues with control systems and physical control configurations (process piping and valves). Water chemistry has also been brought up as a potential contributor to SGS failures, as well as design and manufacturing inadequacies.

Plant designs having measures to incorporate efficient/fast start-ups were not always fully considered. Inefficiency in the start-up process will generally result in solar-field defocusing and loss of energy. These types of impacts occur regularly due to the typical daily start-ups. Specifically, it was mentioned that turbine bypasses are not always optimally placed, which leads to potential steam-temperature quenches at the turbine inlet when switching from the bypass process. It was also brought up that long piping runs from the SGS to the turbine take considerable time to warm up. Turbine start-up curves were also noted as often not being optimal for the needs of a daily-cycling CSP plant. Inefficiency in these curves results in excess/routine solar-field defocusing and loss of energy.

Lack of proper and safe access for both operational and maintenance needs was brought up by participants as a significant issue for the O&M phase. Several plants identified locations of inaccessible equipment and valves where "permanent" scaffolding has been left in place. Some plants had equipment placed such that they were significant safety obstacles and trip hazards.

Several project participants noted a lack of thought into the design for the efficiency and safety of equipment maintenance. It was noted that improvements to plants for these matters needed to be done later by the O&M team.

It was noted that several projects have changed to centralized control rooms where previously there were single control rooms for each plant. The single control-room concept was stated to be non-optimal for site communications, operations, and safety. Lack of visibility from the control room was also brought up as a concern for general safety and operational optimization.

A couple of participants noted issues with water-treatment plants that have resulted in substantial increases in manpower from the O&M phase from what was originally anticipated. Also, chemical storage capacity and demineralized water supply (plant and mirror-washing usage) were inadequate and had to be added later.

Best Practices

- O&M SMEs should be involved with the design phase to alleviate any unrealistic operational assumptions. A design based on, for instance, clear-sky conditions that does not meet the realities of cloudy-sky and transient conditions should be avoided. O&M SMEs involvement should occur early on in this phase.

- O&M SMEs should review the design-process conditions and control schemes that would be used to protect equipment from out-of-spec conditions or gradients.

- Design optimization without O&M specialists will not provide for the proper equipment selection and critical redundancy.

- O&M SMEs should ensure that plant documentation from the EPC meets the O&M needs in terms of quantity and quality. Of special relevance: process and instrumentation diagrams, functional descriptions, O&M procedures, and O&M manuals. To the extent possible, draft documents should be complete prior to commissioning and finalized during and after the commissioning process.

- O&M SMEs should review the proposed water-chemistry program, instrumentation, and lab facility to ensure that they are adequate for O&M needs.

- O&M SMEs should review and be part of the process for developing the specifications for the control systems and ensure that they are adequate for plant operations and

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equipment protection. Adequate alarm management, automation, and logic for process control should specifically be addressed. Manual operations should be limited, as possible, to avoid equipment damage, optimize operations, and ensure plant and personnel safety.

- O&M SMEs should also focus on the design of DCS screens, trending, and reporting quality (necessary for efficient/optimal operation and incident analysis). Knowledge of forced signals for instrumentation should also be readily available to operating and engineering staff.

- O&M SMEs should be fully involved and engaged over the DCS FATs.

- O&M SMEs should review the design to ensure that it incorporates measures for efficient and fast plant start-up. This would include proper placement and configuration of turbine bypass lines; optimal configuration of steam-piping configuration to reduce warm-up times; and review of start-up curves.

- O&M SMEs should review the site plan and ensure there are adequate provisions of stairs, ladders, and platforms to allow safe access for all required plant O&M activities.

- O&M SMEs should review the site plan to ensure that accessibility to equipment and lifting provisions have been considered. They should also ensure that adequate room has been provided to remove and lay down equipment. For example, steam-generation bundles are quite long, so adequate room needs to be provided to pull the bundles and lay them down close to the equipment. It was noted by some participants that, for this reason, the SGS equipment should be placed at ground level.

- The EPC should perform HAZOP sessions with the owner and a third-party specialist for the critical systems and to implement the resulting engineering measurements. It is key that the O&M SMEs attend those sessions.

    - After about 6 months of operation, the EPC, O&M organization, and OE should conduct a HAZOP/LOPA study to assess the fit for service of all systems and controls. This activity should be repeated at certain intervals.

- The EPC contractor should perform a single-point-of-failure and critical-equipment analysis. O&M SMEs should play a very important role in these exercises.

- O&M SMEs should ensure that the design has incorporated measures for maintenance such that equipment can be evacuated/cleared/isolated efficiently. Also ensure that isolation of equipment does not hinder or make unsafe other modes of operation:

    - Double block-and-bleed piping/valve configurations are preferred for security and validation of process isolation in high-pressure steam applications. This configuration uses two isolation valves, with a drain/vent valve between them to ensure isolation and personnel safety. This configuration should also be

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considered in HTF applications; however, the drain/vent requires special awareness due to the environmentally hazardous nature of HTF.

    - Appropriate drains and vents should be included for removing process fluids efficiently and safely.
        - For some critical equipment such as the HTF main pumps or SGS, draining pipes conducted to the low-pressure ullage areas should be considered.
    - Nitrogen should also be considered for use in evacuation of HTF systems. Ensure that a nitrogen source is available near the locations where it will be used. Electrical power and air-supply requirements should be adequate for maintenance activities. Electrical-service supply should consider outage activities such as condenser cleaning, for example. Instrument air and plant air should be separated, and sizing of the air system should account for the highest usage, including during major outages. Sufficient connection points distributed in the power island, water treatment, and maintenance facility should ease maintenance and the use of air-actuated tools.
    - Remote operation of equipment should be considered for plant and personnel safety.

- O&M SMEs should be involved with the selection/review of emergency evacuation equipment being provided or going to be purchased. This would specifically include HTF evacuation equipment for solar-field and power-block HTF-related maintenance work. HTF requires specialized equipment due to temperature and the hazardous nature of the fluid. This equipment should have the ability to create a vacuum to "suck" in HTF from the system. It should also be rated for the operating temperatures of HTF or work in tandem with cooling equipment to reduce the temperature.

- O&M SMEs should ensure that safe and accessibly located sampling points/systems for HTF are included in the design.

- Centralized control rooms should be considered, where applicable. These will typically be beneficial for site communications, good operations, safety oversight, and information gathering.

- O&M SMEs should review the control-room layout. Having a visual of the site including the solar field is recommended. Operators should be involved with the layout plan. Cameras may also add to the visual capability of the operator. Some plants have put cameras that look specifically at the HTF pumps due to multiple failures and the hazardous conditions this equipment presents.

- O&M SMEs should review the water-treatment facility design and ensure that the expectations and potential changes in water-supply quantity and quality are fully considered in the design. Otherwise, substantial increases in O&M should be anticipated.

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4.2 O&M Involvement During Construction

O&M involvement is important during construction to familiarize SMEs with the plant and to specifically address concerns that will impact the O&M for potentially the life of the project.

Background

Several participants noted that lack of O&M familiarity with the plant led to potential impacts later during the O&M phase related to optimized operation and efficient/safe maintenance activities. The O&M period is quite lengthy, and issues not identified and resolved from an O&M perspective during the engineering and construction period may impact the O&M team for quite some time, if not for the lifetime of the project.

Best Practices

- O&M representation should be brought into the project during construction. One participant noted that their more successful projects implemented this strategy compared to ones where the O&M involvement was delayed until later in the project. In this way, O&M learns and becomes familiar with the plant much better, and this knowledge continues to be helpful through commissioning and the O&M phases.
    - This should be a consideration to be contracted as part of the O&M agreement (or other) for pre-operational services with an approved plan on the organizational structure/functions during these phases.
- O&M representation should work with the owner's quality control team. These SMEs can help identify issues that had their involvement during the design stage/review. They should also continually seek out items that would hinder plant operations, equipment access/isolation/maintenance, and safety/environmental concerns.
- O&M representation should get involved with the equipment warranty phase and, ideally, this person should become involved during the construction and commissioning phases. This person should account for a specific position within the O&M organization chart to lead and coordinate all work related to the equipment warranty claims to the EPC during the warranty phase.

4.3 O&M Involvement During Commissioning

O&M involvement is very important during commissioning to ensure that O&M staff is well prepared for the turnover point in the project when they become responsible. Lack of O&M input and participation in this phase has led to inadequate staff training and familiarization, deficiencies in control systems, and incomplete O&M procedures.

Background

It was brought up by most participants that it is crucial to have O&M involved with the commissioning process. Although a more detailed write-up on commissioning is included with this report, this section highlights the O&M-specific involvement and critical roles of this team. It is important to the project's success and equipment protection that the commissioning and O&M teams and procedures are well aligned and that quality procedures are well developed. It was stated that on some projects, the EPC staff does not adequately integrate O&M staff into

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plant operations early enough and is more focused on completing its commissioning and start-up than in integrating O&M operating personnel. In some instances, it was noted that the EPC tends to keep the O&M staff out of the control room or away from the operating stations and often rushes to get to a provisional-type completion stage. As such, the O&M team is not adequately prepared and trained for operations at the time of turnover, and equipment may be operated out of specifications.

Rushing to get to a provisional-type completion stage was also noted as an area where shortcuts may be made. An example of this is where air blows of the steam piping were used rather than steam blows. This occurred to improve the schedule because the plant was not capable of steam blows at that time. This later resulted in damaging deposits on the steam-generator tubes. To magnify this issue, start-up trim was not used in the critical valves, and significant downtime occurred soon after commissioning to replace critical valve trim that was damaged.

Participants overwhelmingly stated the importance of the O&M team being involved with the plant control systems. Often, there is little or no provision in contractual documents for O&M to be involved in the audit/inspection of this system, so familiarization of the system is limited at the turnover point. In many projects, distributed control system (DCS) programming to improve logic, functionality, alarm management, and automation continues well into the O&M phase. Priority alarm lists were noted as often being incomplete, and as such, alarms become a nuisance. This leads to ignoring alarms and may risk equipment protection.

Participants have identified that O&M procedures produced by the EPC at the point of turnover to O&M in some cases are markedly inadequate. Often, these critical documents were noted as being insufficient for the detailed operating procedures required for plant systems and equipment protection. It was noted by several participants that these procedures continued to be redlined and edited well into the O&M phase of the project. In one project, it was noted that the operators would not work outside of procedures due to liabilities.

Quality operating procedures need to be developed and then implemented and enforced by the O&M team management for quality and consistent operations at turnover. Done correctly, this will both optimize output and protect equipment. Most participants agreed that O&M involvement was critical, and at least the O&M team should be involved with reviewing and the approval process of these documents. Typically, after years of experience with multiple plants, O&M teams have developed specific procedures in more detail that assist with this process for some companies' newer projects.

Best Practices

- The owner/OE should use the O&M team to monitor and participate in start-up and commissioning. It supports O&M familiarity with the plant for the plant that it will be inheriting.

- It is recommended that experienced and trained O&M staff be integrated with the start-up staff during the commissioning phase to ensure that the start-up of equipment and systems is done in a similar way to normal operation of the plant.

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    - One participant has suggested that the core O&M personnel, identified and retained by the owner from the beginning when the conceptual design was conceived, should be able to build up an organization that can take over the commissioning based on procedures developed by the EPC and reviewed by the OE/O&M team. During commissioning, the EPC would be in an assisting role of witnessing and remedying deficiencies/punch-list items. This is somewhat different than current CSP project philosophy, although it has worked in at least one instance.
    - Another participant has recommended that, at a minimum, the O&M contractor would be used to pass the initial tests (tests before commercial operation).
- The commissioning and operating teams should work together during the commissioning period. They should be involved with the DCS functionality and tests to validate completeness and should be performed prior to plant acceptance. This would be inclusive of ensuring that:
    - Control logic, warnings, and alarms have been implemented to protect equipment;
    - Automated processes have been incorporated to limit manual operation that protects equipment and have optimized the operation;
    - DCS screens are acceptable;
    - Trending and reporting quality is acceptable; and
    - Knowledge of forced signals is readily available.
- Start-up trim should be used on critical valves during commissioning to limit downtime and costly replacement of valve internals. This should be considered mandatory and not an option.
- More should be done contractually from an operator perspective to be able to audit/inspect plant control systems well in time prior to turnover.
- It was recommended by some participants that O&M needs to be involved with the control systems FAT and involved with the QC of the control system during commissioning. This is to address operational functionality/usability, alarm management, automation, and logic.
- Good O&M procedures need to be created, implemented, and enforced for quality/repeatable operations to optimize production and protect equipment.
- Vendor/OEM training programs should be done either before commissioning, or better, after commissioning. It typically happens that the vendor training programs are carried out during the plant commissioning, which does not allow O&M staff to attend properly to commissioning and/or the vendor training.
    - This is especially critical in remote areas.

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- O&M SMEs should assist in the final review and adjustments of the O&M documentation and procedures prior to the end of commissioning.

- Consider use of experienced O&M companies and teams that have worked well on CSP projects teaming with the EPC during the guarantee period or can demonstrate the capability to do so.

4.4 Turnover to O&M / O&M Readiness

Many participants have noted that O&M teams often are not ready at the time of project turnover to O&M. Deficiencies in training, quality of personnel, completeness of maintenance programs, and inadequate spare-part programs were issues noted among participants. The degree of inadequacy often depends on the contract structure and project partners.

Background

As mentioned in the Commissioning section for O&M, the lack of quality operating procedures has been a common issue that operators face at project turnover. To compound this, in structures where the O&M staff do not work with the EPC commissioning team, they do not get to take full advantage of learning and becoming familiar with the site-specific plant operations. Inexperienced operation or lack of procedural compliance may lead to plant excursions that damage major equipment such as heat exchangers. This can subsequently require extensive outages that impact the COD or PPA commitments.

From many participants' perspective, training was improved over time as CSP-specific experience was gained through involvement with early projects. This has been beneficial to later projects. However, it was still noted that some O&M companies lack a sufficiently rigorous or formal training and qualification process.

Other plant systems—including the setup of computerized central maintenance system (CMMS) software, warehousing, and spare-parts ordering/tracking systems—were noted as often occurring after the turnover process and well into the O&M phase. Capital expenditures and critical/inventory spares were often not considered until later and sometimes did not consider a strategy for common spare parts with owners of multiple facilities.

Best Practices

- As the project contract allows, the owner should consider the commitment of investment to have O&M personnel onsite for training (and QC) purposes during construction, start-up, and commissioning.
  - This should be a consideration to be contracted as part of the O&M agreement (or other) for pre-operational services with an approved plan on the organizational structure/functions during these phases.

- O&M providers for CSP facilities should have rigorous or formal training and qualification processes in place. Providers should not rely solely on training during commissioning, which should instead be a supplement to their existing experience.

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Training, qualification, and set-up of procedures should begin during the construction phase of the plant.

- Plant simulators would likely be beneficial for training and familiarization of plant procedures and operations. It is believed that simulation for CSP plant operations for training purposes is in its infancy; yet, technology seems to be available to develop this concept more thoroughly. This could be an area of future development and improvement among the CSP community.

- Milestone payments should be considered for operational readiness key performance indicators (KPIs) prior to COD. Examples of operational readiness include:

    - Developing and approving an O&M plan per the O&M agreement.
    - Ensuring that all permits, licensing, and insurance requirements related to O&M are in place.
    - Developing Health Safety and Environment (HSE) and Lock Out Tag Out (LOTO) libraries that are completely defined and functional. O&M staff should be properly trained on these systems.
    - Capital expenditures. Owner with multiple plants should consider equipment to be specified for sharing of spare parts (pumps, valves, turbines, instruments), when possible.
    - Critical spares and a general spare-part list complete and in stock:
        - Spare parts are often not considered wisely. It is not possible that every single part recommended as spares for every piece of equipment can be purchased. This needs to be thought out very carefully, and O&M SMEs need to be involved with this.
        - Critical spares should be considered and defined contractually before the start of the O&M phase.
    - Consumables should also be considered (oils, greases, and chemicals).
    - Warehouse, workshop(s), and laboratory facility arrangement design.
    - Special tooling identified and purchased (turbine specialty tools, for example).
    - Purchase of HSE, O&M equipment/tools: HTF evacuation equipment; mobile equipment; vehicle fleet; mirror wash equipment including the mirror reflectometer; mechanical, electric, and I&C equipment and tooling, safety equipment, and personal protection equipment.
    - Maintenance planning systems, CMMS, in place and functional. The equipment hierarchy, bill of materials, and predictive and preventive work orders associated with each equipment fully defined.
    - Long-term service agreements (LTSAs) and general service agreements in place.

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4.5 O&M During Commercial Operation

The primary role of the O&M company is to provide diligent and safe operations and maintenance for the facility. This is typically outlined in an annual O&M plan, which, in general, includes the plan and goals for plant performance; staffing; training; plant operations; water treatment and chemistry; power-block maintenance; solar-field maintenance; safety compliance; regulatory compliance; contractual compliance (O&M agreement and PPA); inventory management; and budgetary compliance. Lack of good planning and execution of any of these topics will likely impact the O&M quality/costs of the project. Regular monitoring of project KPIs related to these plan goals is required to ensure that the actual plan goals are being met, and if not, that action plans to address deficiencies may be necessary.

This section specifically discusses O&M costs, operations, water chemistry, maintenance, and procurement. These are the topics where concerns and best practices were provided and discussed with project participants.

4.5.1 O&M Costs—General

O&M involvement is critical starting early in the project, and when done this way, it has been reported by many participants to improve the O&M quality of the project. However, many challenges remain to ensure a quality O&M team including obtaining experienced and qualified personnel. It was noted that cost estimates should be accurate and ensure that an experienced team can be formed and maintained for the project. Labor is a significant portion of the O&M budget, and it is often not estimated with due diligence.

Eventual O&M costs were generally stated as being higher than anticipated or budgeted at financial closing. There tend to be issues that are not fully considered, and it generally falls to the owner to pick up additional costs. It was also noted that, in many cases, O&M costs increased over time as the degradation of certain components increased, which was not considered in the O&M cost estimate. Labor costs were reported as being estimated incorrectly, in some cases due to lack of automation that had been designed for the operations of the facility. In these cases, increases in operations staff were needed over what was anticipated. In other cases, labor costs were not estimated based on the local wage structures and regional consideration for CSP and power-generation industry experience. Also, consideration for additional staff may be needed in the early years for technical expertise and equipment warranty support. This type of support/positions should be expected to phase out over time.

Often, solar projects are located significant distances from major cities. For the construction crews, this is not an unusual situation. However, securing a source of experienced O&M personnel within commuting distance of the projects is typically problematic. New areas/countries for plants and developers have also proven challenging from a standpoint of experience, wages, and culture. In some areas, lack of experience has proven to be a serious issue. In some of these cases, experienced workers from distant locations would be used for temporary/long-term assignments in a remote location. Done in excess and for long periods can be quite expensive. Some regions were mentioned to have workers with less motivation than in other areas, and often, this was related to the local culture. Other locations were mentioned as having workers with very high motivation/low wages, yet minimal experience.

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It was mentioned by several participants that projects built regionally, close to other existing projects using familiar contractors, have improved in O&M quality and costs with faster learning curves. In these cases, experience was gained and then applied to the newer projects.

Best Practices

- Do not get cheap on O&M. Ensure that the O&M contract will allow the O&M provider to hire quality experienced personnel in time and pay them a reasonable wage to keep them employed long term.
- Consider pay structures of O&M personnel from rates of regional CSP and power-generation facilities. Understand regional labor conditions and potential for unionization and its potential effects.
- The structure of the O&M team should consider technical expertise such as a plant mechanical engineer, electrical engineer, I&C engineer, and DCS specialist(s).
- For the first one or two years of operation, a CSP plant may need to hire a number of CSP specialists with the key objectives relating to the local/permanent staff training, O&M plans, procedures development, and implementation of other key projects such as for the DCS alarm system fine-tuning, and plant control/automation fine-tuning.
- Resources need to be considered to properly cover the Equipment Warranty and Performance Management Protocols agreed with the EPC contractor and off-taker, if applicable. These activities inherently require a significant contribution from the O&M contractor to be properly carried out and are normally left out from the original plans.
- With realistic expectations in the early years of O&M for the level of staffing required, financial models should not assume that the later years are the same. Similar to production ramping up over time, O&M staffing should ramp down over time.
- Assumptions for plant operating automation processes need to be realistic and implemented correctly during design, start-up, and commissioning. If not, increases in labor will likely occur.
- Consider an adequate payment structure for solar-field technicians. At many facilities, people in these positions want to move out of the solar field into plant operations because of higher pay opportunities. In this manner, the plant "loses" good solar-field technicians, likely diminishing performance.
- Consider local conditions and culture as part of the site selection. Also consider local service providers' experience to support plant issues. Understand these restraints and build assumptions into the project structure before making the decision to move forward.
- Consider degradation of equipment and associated additional expenses for long-term O&M cost estimates.

4.5.2 Operations

Diligent plant operations are critical to the long-term success of CSP projects. An experienced and well-trained operations team is necessary due to the complexity of CSP plant operations. As stated in the previous section, often acquiring adequate experience within the operating staff can be challenging. The problem is compounded by the relative immaturity of the technology and the complexity of the systems. Specifically, combined-cycle plants are as complex as CSP plants. However, combined-cycle technology has progressed to the point where robust designs are commercially available from competing suppliers. Further, the plant operating procedures have been honed to the point where the DCS can safely, and automatically, control all the plant operating modes. Some CSP plants have achieved this kind of automation/control in specific areas, but CSP plants, in general, have not achieved this level on a consistent basis.

At this stage, CSP technology has yet to reach this level of commercial maturity. Operating modes have yet to be fully refined to the point where the DCS can automatically run the plants on a routine basis. The problem is compounded by the poor availability of certain equipment, such as the heat tracing, flow meters, and pressure transmitters (reliability of heat tracing and instrumentation has been noted as more troublesome with salt systems). To safely run a plant, the operators must have a thorough knowledge of the systems, but also, a thorough knowledge of the equipment that makes up the systems. Further, in the absence of routine automatic control through the DCS, the operators are often required to develop operating procedures on an *ad-hoc* basis, particularly if some of the equipment is not operating as expected. Generally, the operators are not aware of the various engineering topics, such as low cycle fatigue and transient thermal stresses, and they will need to work with engineers on any operational changes to avoid equipment damage.

In addition to plant operations, the operations crew typically will oversee and be responsible for the LOTO process to ensure safe isolation of equipment for maintenance purposes. A thorough understanding of the plant's systems is necessary to avoid personal injury and/or equipment damage.

Water treatment and chemistry is typically another critical task that the operations team oversees or is involved with. Poor design of water-treatment systems and changing conditions of the incoming water supply have caused unexpected capital costs and increases in labor. Lack of good water chemistry has contributed to equipment failures. These matters and best practices associated with them are discussed in detail in the following Water Treatment and Chemistry section.

Best Practices

- An operations core team should consist of operators experienced and qualified in CSP operations, and to a lesser extent, power-generation operators. Experience with CSP systems and transients is essential.

- To help resolve inexperience issues, the EPC must institute the following:

    - Refine the plant design to the point where essentially all of the plant transitions between operating states can be mostly automated. This is primarily an exercise in developing reliable instruments or providing enough redundancy in the instruments such that the failure of one instrument does not affect the automation sequences. Salt instrumentation has been noted as being rather unreliable and requiring additional attention.

    - Refine the DCS to have control and protection warnings and alarms for the operator intervention to prevent equipment damage.
    - Refine the plant design to provide the equipment necessary for each system to operate safely, for extended periods of time, at the 1% load condition. If this can be accomplished, then the transitions will become repeatable, and therefore, amenable to automation.

- Additional operational and engineering experienced SMEs should be considered for the early operational period of the project while the control/automation and staff experience is being developed and proven.

- Quality operating procedures must be developed early in the project. Operations and engineering SMEs should be involved with developing and approving these procedures during the construction phase. Operations procedures should be enforced, and there should be a process to audit, modify, and maintain quality procedures.

- Plant conditions should be regularly monitored to ensure the procedures, controls, and strategies are optimizing the operations and staying within the limitations of equipment—as an example, temperature gradients for heat exchangers and pumps.

- Rigorous and continuous training of plant operators is essential. A qualified operator team is an important component for maintaining a continuous training program and ensuring that delegated site personnel remain trained and available to assume operator duties.

- Consider operator training with a simulator, if available, to demonstrate to the project owner that the staff has the skills necessary to operate the plant safely and economically. The training should include emergency conditions, such as a pump trip, a loss of a flow signal, and erroneous instrument readings.

- A good technical performance model and some key performance management tools should be used regularly by the O&M management and staff. An example is a Daily Production Report, which is intended, among other tools, to estimate production losses and check key performance/operating indicators.

- Project operations KPIs are important to define, be monitored, and used throughout the organization. Specific operational KPIs should be identified and used based on plans and goals developed in the O&M plan. These KPIs will typically center around safety performance and compliance; regulatory compliance, plant performance and availability; budget; personnel training; plant operations (forced outages/trips, start-up delays), and water chemistry.

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4.5.3 Water Treatment and Chemistry

Water treatment and steam-cycle chemistry is vital to maintaining high availability of a CSP plant. Proper water quality, chemistry, and equipment passivation methods are necessary at the very initial stages of plant operations, beginning during the start-up and commissioning phases. This is mandatory to avoid potential issues that may not fully impact availability of the plant until later years. In some instances, availability issues have shown up much earlier.

A significant number of tube leaks in nitrate salt steam generators have been attributed to improper water chemistry. Chemical parameters including dissolved oxygen, pH, and chemical additives were found to be out of tolerance. If left uncorrected for even a modest period (e.g., months), then significant corrosion can occur of the carbon-steel materials in HTF and nitrate salt SGS loops, and of the stainless-steel materials in nitrate salts SGS loops.

Background

The equipment that has been most affected due to poor water quality/chemistry according to participants of this project is the SGS. In several cases, poor water chemistry has led to failures and availability issues of this system. The SGS, however, is not the only equipment susceptible to water quality and chemistry. The steam turbine has very stringent standards for water quality/chemistry, as do the condenser, cooling tower, and open/closed cooling system.

One of the goals of the water-treatment system is to establish the conditions for forming magnetite (Fe_3O_4), rather than hematite (Fe_2O_3), on the carbon-steel surfaces of the condensate and feedwater systems. Magnetite corrosion layers are more adherent than hematite corrosion layers and, as a result, are less susceptible to flow-accelerated corrosion. Flow-accelerated corrosion, as the name suggests, is the erosion of metal corrosion layers. It is most prevalent in carbon steel at a temperature over 150°C, in regions of high water or steam velocities.

Hematite particles in the condensate system have the potential to accumulate in regions of low velocity. One location is the bottom of the steam drum. Systems with forced recirculation draw suction from the bottom of the drum. If the nozzles for the recirculation lines do not extend somewhat into the drum (~150 mm), then particles will not be trapped in the drum. As such, the particles can be drawn into the recirculation pumps and potentially cause damage to the pump rotor and seals.

Another potential source of accumulating solid particles is the location of a phase transition from liquid to vapor. An example is the inside of an evaporator tube, perhaps 1 to 2 m from the inlet tubesheet. Particles deposited on the stainless-steel tubes of the evaporator lead to pH values underneath the deposits that differ from pH values away from the deposits. The pH gradient establishes a galvanic cell, which leads to pitting corrosion beneath the deposits. The tubes in the evaporator have thin walls (1.6–2.0 mm), and leaks from the water-side to the salt-side can develop in less than a year.

The dissolved gases normally present in water may contribute to corrosion problems, as well. The resulting corrosion leads to deposits on heat-transfer surfaces and reduces efficiency and reliability. The principal source of dissolved oxygen is air leakage into the condenser. The principal method to remove dissolved oxygen is to raise the temperature of the feedwater to the saturation condition inside the de-aerator and to vent the non-condensable gases released from

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the feedwater. If the de-aerator cannot establish a proper dissolved-oxygen concentration level, then an oxygen scavenger can be added to the feedwater.

Material selections of piping and equipment should consider water chemistry and control based on incoming water-supply quality and projected future conditions. Some sites have had ground-water quality change significantly such that major modifications were required for water treatment and blow down. The selection of material may contribute to other impacts in addition to water chemistry. For example, condenser tubes at one facility were stainless steel and were outstanding from a reliability standpoint. The downside was that they required a low chloride level of water in an already high chloride water supply. This resulted in a low cycle count for the cooling tower (more water usage) and a continuous water flow through the condenser 24 hours a day. A smaller pump was not provided in the design for this lower required water flow during non-production hours; thus, there was a higher parasitic load for having to use a large circulating water pump, which was not anticipated in the design.

Raw water supplied to a CSP plant differs significantly by project and location. Participants have mentioned during this project that water sources range from piped-in water (sometimes potable), local well water, local river water, and even rainwater. Some plants have been designed to collect rainwater and route this to ponds to be used later for plant water. Treatment systems vary dramatically for water quality depending on the incoming water supply. The most common methods for poor water quality with high levels of dissolved solids is a pretreatment plant that includes a type of clarifier system. These types of systems are often very labor and material intensive to operate and maintain, and often these factors are not considered adequately. After this initial stage—or if the water is relatively good to begin with—reverse osmosis membranes are typically used in more modern plants. These may be combined with a mixed-bed demineralizer or electro-deionization process for final polishing. Different configurations of this equipment can be and are used depending on the design. It has been noted that at some plant locations, changes in the incoming water quality has occurred, and the design was not sufficient to adapt to these changes.

Regarding water chemistry, it has been noted that in some cases there has been a lack of staff attention/monitoring of the plant's water chemistry and an over-reliance on instrumentation and automated sampling and dosage systems. This has resulted in out-of-specification conditions leading to accelerated corrosion, damage, and early failure of piping and equipment. One participant also mentioned that poor passivation procedures were performed during start-up and contributed to failures. Passivation is a process performed where a protective layer of magnetite is formed on the metal surfaces of the condensate, feedwater, and SGS systems.

Best Practices

- Changes to the quality and/or quantity of the incoming water supply should be considered for the design of equipment. Historical records of the water supply should be studied, if available. A system designed and built with limited capacity may lead to production impacts as conditions change.

- Involving a water-treatment SME should be considered when choosing a water-treatment program for the project. Many factors influence the treatment program and chemicals used. Considerations are necessary for process conditions (temperatures, pressures, cyclic

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operation) and material for cooling tower design (wet and/or dry); equipment cooling system (closed/open); condenser; and SGS.

- Careful consideration should be given to the choice of tube materials for the evaporator. In some salt steam-generator designs, stainless-steel tubes have been selected in the interests of controlling corrosion rates on the salt side. However, austenitic materials are not permitted if the heat exchanger is designed to Section I of the ASME Code or to various EN standards due to the potential for chloride corrosion. An alternate material is ASTM A 213 Grade T91. This is a 9 Cr - 1 Mo ferritic steel, which is more resistant to stress corrosion cracking and pitting corrosion than an austenitic material.

- Proper passivation techniques must be implemented on the condensate, feedwater, and SGS systems for corrosion protection.

- If there are problems with the condensate de-aerator, a temporary portable de-aerator can be brought on site to minimize the effects on the plant's energy production.

- The vent valve on the de-aerator must have an actuator to allow the operators to remotely adjust the position of the valve in response to changing process conditions.

- The steam drum should be inspected periodically for deposits of hematite. This would be one indication of improper water chemistry and consequential flow-accelerated corrosion.

- A water chemist or SME should be responsible for implementing and carrying out the water-treatment program based on a "Water Chemistry Manual." This person should be a regular employee at the project site.

- A "Water Chemistry Manual" kept up to date should be the centerpiece of a water-chemistry program operated under best practices. This should be written or reviewed by an SME familiar with the site's water-quality process and chemistry. An effective manual would likely include the following sections: system description/overview; instruments installed and grab samples/readings; analyzer calibrations and lab test procedures; chemistry program overview; chemical feed, storage, and controllers; program limits and response to transients; shut-down, start-up, lay-up programs; and compulsory responses to out-of-service conditions.

- Water chemistry and adhesion to the "Water Chemistry Manual" should be checked and validated by a third-party SME periodically (monthly or more often, if necessary).

- Institute a water-chemistry training program and manual.

- Benchmarking of key performance indicators and key operating indicators (KOIs) is important. KPIs are measurements of whether goals and objectives are being met. Examples might include steam purity; condenser efficiency; iron- and or copper-level trends indicating corrosion protection; corrosion coupons; and run interval between cleanings. KOIs are measurements of system variables that contribute to whether or not KPIs are met. Examples may include pH; condenser vacuum; terminal temperature

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difference; condensate conductivity; inhibitor levels; free chlorine; dissolved oxygen; and ammonia.

- Key chemical parameters are best measured by online instrumentation chosen for the steam cycle to (1) confirm satisfactory steam quality to send to the turbine(s), (2) confirm lack of condenser leaks, (3) certify suppression of conditions that promote formation of deposits, and (4) minimize corrosion of cycle assets.

- Every plant should maintain at least “industry-standard” instrumentation. “Industry-standard” arrays should give clues about out-of-calibration or out-of-service instruments upstream or downstream of affected probe/amplifier so that validation of a problem is facilitated, thus minimizing required operator time. Industry-standard equipment would include measurements for: conductivity, pH, cation conductivity, sodium; silica, dissolved oxygen, phosphate, and oxidation-reduction potential.

- The analyzer signals should be fed to the control-room DCS and alarmed.

- Routine water-chemistry testing (grab samples) must be conducted in an onsite laboratory to verify the readings from remote sensors. Proper use of grab samples is to: support confirmation of analyzer's calibration; gather additional information, such as iron or chloride testing; and provide additional diagnostics when key targets are compromised.

- Grab samples can become the data source when installed instruments are not maintained or not included. This is not industry-standard practice and should not be the norm.

- Grab samples should be chosen and used to support operations. Well-selected industry-standard instrumentation should minimize the need and frequency for grab samples.

4.5.4 Maintenance

Power-block maintenance is, in general, similar to that within the power-generation industry. As such, fundamentally, many practices are available and known from that industry. The cyclic nature of CSP plants is often more demanding on equipment, so that should be considered. The HTF systems in trough projects and the nitrate systems in central receiver projects—due to the high temperature and hazardous conditions—require specific attention, and preventative maintenance/reliability programs should be set up and followed accordingly to ensure equipment availability. The importance of secure isolation and efficient/safe evacuation of fluid from HTF- and salt-related equipment has been discussed earlier in the O&M section and cannot be overstated to ensure continued equipment reliability and personnel safety.

Parabolic Trough Projects

Solar-field maintenance, however, is relatively new to the power-generation industry and relies mainly on experience gained within CSP plants. As with the power block, the HTF system within the solar field should have reliable isolation and an efficient/safe design for the evacuation of HTF. SMEs in solar-field maintenance should be involved with the design and equipment selection to ensure that this step occurs. Maintenance requirements are different for specific plants due to so many differences in the collector, drive, and control-system design and are not specially discussed here due to these many variations. Due diligence, however, should be

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performed to estimate maintenance requirements and monitoring strategies for this equipment. Two maintenance practices mentioned consistently by participants as concerning are ball-joint maintenance and mirror cleaning.

The move from flex hoses to ball-joint assemblies (discussed in the Trough section) has led to unexpected increased maintenance labor requirements in the solar field. This is a very concerning matter among participants. Graphite is used to pack ball joints to prevent vapor leaks. However, as mentioned in other sections, ball joints tend to bind if overpacked with graphite or leak vapor if underpacked with graphite. If a ball joint binds too much, it may lead to a bigger failure within the receiver string—typically at a weld joint, where the fluid will leak out of the system due to a crack or break in the piping/welding. Vapor leaks have caused environmental concerns at some projects, which has led to substantially increased staffing levels to reduce the level of leakage to meet permitting requirements.

Although this topic is discussed in greater detail in Section 5, it is important to note that with the growing concern over the performance impact of hydrogen permeation into the receiver tubes (created as a byproduct of the degradation of HTF), it is vital that the O&M contractor take measures to minimize this risk. The O&M contractor must operate the ullage system regularly (for removal of both high- and low-boiler content) and ensure the ullage unit is functioning correctly. The HTF should be tested regularly to ensure that properties of the HTF are being maintained. Typical property samples of the fluid can be performed by the manufacture (or other qualified labs) to test for: high boilers, low boilers, pH, and water content. In addition, periodic samples should be sent to a laboratory to test for the hydrogen content in the oil. Only one known laboratory—the German Aerospace Center (DLR)—is known to be able perform this service. Periodic measuring and monitoring of the receiver-tube temperatures during operation is also mandatory to ensure the best performance. Not exceeding design temperatures of the HTF is important to limit hydrogen generation, and operating at lower temperature should be a consideration.

Nitrate Salt Projects

Nitrate salt is chemically stable in the presence of air (in the ullage space of the thermal storage tanks) and in the presence of water (due to leakage in the steam generator). However, water contamination of the salt can lead to three problems:

- Cavitation damage to salt control valves in throttling applications; i.e., the downcomer-level control valves.
- Transport of water vapor from the hot-salt tank to the receiver through the receiver vent line, followed by condensation of water in the receiver when the ambient temperature falls below the dew point. Liquid water has been shown to lead to intergranular stress corrosion cracking of both 300-series stainless steels and nickel-alloy steels.
- During overnight hold periods, the temperature of the steam generator is maintained at a nominal value of 290°C by circulating salt from the cold tank through the heat-exchanger train, and then back to the cold-salt tank. Water leakage significantly increases the thermal demand on the cold salt. In some cases, the increased demand requires the turbine to be operated at non-optimum conditions to artificially raise the temperature of

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the cold salt leaving the steam generator, and thereby, provide the energy necessary for overnight hold.

Common stem-packing materials in salt valves include graphite-impregnated wire mesh, Teflon, and vermiculite. Nitrate salt chemically reacts with these materials, resulting in changes to hardness, ductility, volume, and coefficient of friction. These changes, in turn, can produce low leakage rates past the packing. The volume of salt is typically small; however, the salt comes into contact with the heat-trace cables. The cable temperatures are high enough (>650°C) to thermally decompose the salt. Some of the decomposition products are various oxides, which corrode the exterior cover on the heat-trace cable. Once the interior of the cable is exposed to moisture in the air, failure of the cable is essentially assured.

During hold periods, the temperature of the salt piping and valves are maintained at a nominal value of 290°C by means of the electric heat tracing. Heat tracing is expensive, and in many projects, the thermal capacity of the heat tracing is only marginally greater than thermal losses to the environment. As a result, even minor gaps or defects in the insulation can result in equipment temperatures below the freezing point of the salt.

Topics Common to Both Technologies

Keeping mirror cleanliness up to expected conditions has been problematic among participants. Although some have stated that they have been able to meet expectations, most have stated issues in achieving design conditions. The issues have generally been noted as: different fouling factors at the site than were anticipated; use of inadequate machinery for cleaning; and inadequate water supply. Some plants self-performed this work and others contracted out this work.

Soiling rates were said to be affected by differences in wind speed, dust levels, rain conditions, and combinations of these. For instance, light rain combined with high-wind dusty conditions was noted to have a significant increase in the soiling rates. In one area, it was noted that the ground was “frozen” in the winter and little or no dust occurred despite high wind speeds, and thus, cleanliness could be maintained to expected levels. However, in the other months at the same site, this did not hold true and the area was very dusty, resulting in a high soiling rate of the mirrors.

Often, it was noted that equipment failures from complicated mirror-cleaning machinery negatively impacted cleanliness. One site noted high equipment failures, but also, long downtime with the equipment because it was manufactured in another country and parts were not readily available at the site location. Equipment not designed with enough water capacity required “nurse” trucks to drive back and forth to the fill point of the plant. One facility noted that the mirror wash equipment was not suited for travel with the site roads and solar-field conditions per the design of the project.

Both power-block and solar-field maintenance groups typically use CMMS software to manage scheduling and work orders for preventive and corrective type activities. Generally, these systems tie to an inventory management and financial system. This type of configuration, if set up correctly, allows for accurate tracking of time and material costs for maintenance activities in an efficient manner, and it triggers the purchase of replacement parts removed from inventory. It

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was noted by several participants, however, that these systems did not function well for O&M purposes; instead, they used additional resources to manage and track maintenance activities. These systems were stated as being more problematic for the solar-field portion because of the quantity of components and parts and the need to track these to specific locations on the individual collectors within the solar field.

The maintenance management software should be set up to track corrective maintenance activities, but also be developed with a rigorous equipment preventive maintenance program. This preventive maintenance program should be based on equipment manufacturers' recommendations and industry standards, and it should include both the power-block and solar-field equipment. A good preventive maintenance program typically results in higher equipment availability.

Predictive maintenance programs have been stated to help increase availability of plant equipment. Being able to monitor and identify equipment issues before failure will help target specific areas for maintenance, assist with optimizing the maintenance planning, decrease cost in maintaining equipment by identifying issues early, maintain higher reliability of equipment, and ultimately, result in higher plant availability.

Given the process complexity and the amount of process data in CSP plants, digitalization is starting to play a key role. Digitalization expands focus from one specific area to the entire maintenance process. With a digitalization strategy, organizations can review the maintenance process as a whole to look for benefits, cost savings, and optimization solutions.

Best Practices

- Carefully consider and perform due diligence on selecting parabolic trough collector flexible piping interconnections. It is unclear from this NREL study whether a thoroughly proven design has been developed. The interconnection should not leak (vapor or catastrophically) and not bind, and it should not require significant labor hours to maintain.

- To prevent hydrogen-permeation impacts of the trough receiver, ensure that ullage systems for HTF plants are operating correctly and routinely to remove high and low boilers. Test the HTF fluid regularly for high- and low-boiler content as well as for hydrogen. Manage operating temperatures and consider lowering the operating temperature of the HTF.

- If water condensation is discovered in a salt receiver, then repairs to the steam generator should be initiated as soon as practical to reduce the potential for intergranular stress corrosion cracking in the receiver tubes.

- Salt leakage past valve-stem packing must be monitored on a regular basis, and replacement of the packing must be effected as soon as practical.

- In salt piping and equipment, the integrity of the thermal insulation and heat tracing must be monitored on a regular basis, and repairs must be effected as soon as practical.

- Carefully consider and perform due diligence on mirror-cleaning equipment. Ensure: reliability; parts availability; effectiveness; use with site conditions; and water usage and support requirements.

- Consider using different mirror-cleaning technologies at site—for instance, deluge and brush-wash technologies. In this example, the deluge could be used to maintain cleanliness (high water volume, many collectors per equipment, low effectiveness), whereas the brush wash would deep clean (low water volume, few collectors per equipment, high effectiveness).

- Consider the potential for high soiling events and develop a rapid-response plan to address potential events.

- Consider both contract services and self-performing site mirror cleaning. Site location may dictate what is most appropriate.

- Demineralized water-supply capacity must consider water usage for mirror washing.

- A maintenance management system should be specified, purchased, and implemented early that addresses the needs of managing maintenance activities at the plant. Special consideration should be given to ensure that the system meets the requirements for the solar field. Financial programs with maintenance modules have been mentioned as being inadequate for this purpose, although it is likely that the maintenance management system will need to communicate or be integrated with a financial and inventory management program. O&M personnel should be involved with specifying, selecting, and developing this system.

- A rigorous preventive maintenance program for both the power block and solar field should be implemented. Routines should be determined based on equipment manufacturer recommendations and industry standards. Schedules should be adjusted accordingly based on actual site equipment reliability.

- A solar-field optimization should be performed periodically and included in the maintenance management program. This would include flow balance, inclinometer calibrations, and collector alignment checks as examples. Results could be used for decisions to be included or not into plant-improvement programs.

- A predictive maintenance program to foresee failures should be implemented and followed that uses appropriate sensors and instruments placed on key equipment that feed to a central location for collection and analysis. Key components commonly tracked would include turbines, heat exchangers, pumps, and transformers. Monitoring for HTF gas presence in salt tanks and potential leaks in salt tanks have also been considered important parameters to monitor.

- Project-maintenance KPIs are important to define, be monitored, and used throughout the organization. Specific maintenance KPIs should be identified and used based on plans and goals developed in the O&M plan. These KPIs will typically center around safety

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performance and compliance; plant performance and availability; budget; personnel training; corrective, preventative, predictive work orders, regulatory compliance, and inventory management.

4.5.5 O&M Procurement/Contracting

Other important cost-related items for the project are related to procurement and inventory decisions. It was stated that, in some cases, procurement decisions are based too heavily on cost savings without enough consideration for quality, availability, reliability, and effectiveness. As such, the onsite O&M team may take the responsibility of non-availability from a procurement decision.

Where projects are being operated in remote areas, it can be very useful to contractually require a minimum callout time for suppliers or specialist service staff to arrive onsite. Long-term service agreements can also be used to set minimum lead times on spares and wear parts in instances of unplanned maintenance. These have been particularly important and effective on turbines and generators, pumps, critical transformers, and switch gear.

If LTSAs are not negotiated as part of the EPC procurement period, then higher costs are typically seen. Few projects negotiated service agreements at procurement.

Some participants had different opinions on LTSAs. Specifically related to turbines, some felt they had more flexibility on timing of outage intervals and service-provider selections that could potentially save costs without an LTSA. Experience of the owners and O&M team may likely dictate the decision in these matters.

Location is critical for determining spare-part levels that should be stocked and available in a warehouse. Some companies with multiple projects in relatively the same region may use more central warehouses that the fleet could draw from. In some regions, spare parts have low availability and long lead times, so inventory levels would need to be adjusted appropriately to account for this. Also, some areas have low availability for service providers, and delays can occur for mobilization of crews. Often, in these cases where service providers may be scarce, costs are likely to be inflated and have been noted to be up to two times more expensive. These considerations should be planned and accounted for.

Best Practices

- A balance needs to occur between Procurement and O&M site personnel on dealing with least-cost versus long-term availability. Lowest-costs solutions do not always result in the lowest net project costs when availability (or lack thereof) is considered.

- LTSAs should be considered. Remote and less experienced owners may be more comfortable with the advantages of an LTSA. It is important that LTSAs be negotiated as part of procurement (EPC process) to ensure better pricing. LTSAs for consideration brought up by project participants have included the turbine/generator sets and DCSs. Other critical equipment should be considered based on the conditions/needs of the project.

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- Understand local conditions for determining spare-part levels and costs. Service provider costs should also be understood, as well as the availability/readiness/response time for applicable services.

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5 Parabolic Trough Technology

Figure 5-1. 160-MW_e Noor Ouarzazate I Parabolic Trough Plant, Ouarzazate, Morocco

The LUZ Solar Electric Generating Systems (SEGS) projects represent the first wave of commercial parabolic trough power plants. Nine projects, ranging in size from 14 to 80 MW_e (net), were built in the California Mojave Desert between 1983 and 1990. These projects had attractive 30-year PPAs, and most have now reached the end of their contracts and have begun closing. Several of the projects have gotten extensions on their PPAs and continue to operate, but several others have closed and have been or are being decommissioned. Technically, the plants could continue operating, but the economics of CSP plants without storage in the California competitive market do not cover the O&M costs. However, these projects offer 30+ years of operational experience that has proven valuable for understanding lifetime and performance of many elements of trough technology.

The LUZ parabolic trough technology evolved significantly through the nine projects and became a robust technology. Many technology issues present in early projects were identified and corrected in later projects. LUZ filed for bankruptcy in 1991 when the company was unable to finance its tenth project due to a delay in extension of a state property tax exemption that delayed the start of construction and made it difficult to complete construction and start commercial operation as required by the end of the year. In general, the cause was a lack of stable policies, declining incentives, and falling energy prices. KJC Operating Company took over the operation of the SEGS III–VII plants located in Kramer Junction. KJC initiated a project with Sandia National Laboratories[11] to look for opportunities for O&M cost reduction. This project helped to address a number of technical issues experienced at the projects and to define some of the future technical directions of trough technology.

The development of the EuroTrough collector in Europe and indirect thermal energy storage for trough technology in the United States and Spain helped define the next-generation development of trough technology. Commercial interest in CSP technology remained alive due to the World

[11] Cohen, G., D. Kearney, G. Kolb, "Final Report on the Operation and Maintenance Improvement Program for Concentrating Solar Power Plants," SAND99-1290, June 1999.

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Bank's Global Environment Facility, which was supporting the development of integrated solar combined-cycle (ISCC) projects in India, Egypt, Morocco, and Mexico.

However, it was the Spanish feed-in tariff implemented in 2007 that provided the market incentive leading to the next major wave of parabolic trough plant development. The FIT implemented in 2004 was not high enough to allow projects to be undertaken. As a result, several Spanish engineering and construction companies mobilized capabilities to build CSP plants in Spain. Between 2007 and 2013, some 45 parabolic trough projects were built in Spain totaling 2,275 MW[12] of capacity. The FIT demonstrated how policy can quickly scale up the deployment of a technology. The Spanish FIT did enable some new technologies to be commercialized, including several new trough collector designs—for example, the EuroTrough, Abengoa's ASTR0, and the Sener Trough. It also enabled indirect TES to be commercialized. Unfortunately, because the FIT was a fixed price and did not decline over time, it did not encourage cost reduction and improved competitiveness in the industry. The cost of the FIT became an economic consideration for Spain as it was managing its financial recovery from the 2009–2012 global downturn, and the FIT program for CSP was terminated. Spain went further and made legal retroactive changes to the pricing structure for projects already in operation. The changes limited the maximum amount of energy that each plant could sell to the grid and receive the FIT to below the original generation forecasts for most plants. This has resulted in a re-optimization of the O&M efforts for these plants.

As a result of the FIT in Spain, when opportunities began to appear in other countries, Spanish companies were experienced and well positioned to develop and construct projects internationally—especially in the Middle East and North Africa region, South Africa, and the United States. International projects benefitted from the experience that Spanish companies gained in the Spanish market. However, international developments have been challenging because companies have had to deal with issues of working in new countries and often in very remote regions. The challenges were not isolated to work in developing countries only, but also in countries such as the United States, where similar challenges were faced.

The CSP demonstration program in China will likely be the next major driver of CSP technology globally. Although the Chinese CSP solar resource is relatively low and in very cold regions, the government has implemented a program to jump-start the CSP industry in China.[13] The program has a goal of 5 GW of CSP projects in two phases. The first phase has 21 projects approved with more than 1 GW of capacity. Seven of these projects were parabolic trough plants. The original program had a very tight schedule and only three projects (one trough) met the original commissioning target; but China is modifying the rules, which should allow more of the projects to be completed over the next few years. The CSP industry in China appears to be maturing, with several large companies emerging as the leading industrial suppliers. Chinese EPC companies have already started expanding into the international CSP market, with the participation in the

[12] SolarPACES CSP Project Database, https://solarpaces.nrel.gov/.

[13] Gosens, J., C. Binz, and R. Lema, China's role in the next phase of the energy transition: Contributions to global niche formation in the Concentrated Solar Power sector, *Environmental Innovation and Societal Transitions*, Volume 34, March 2020, pp 61–75, https://doi.org/10.1016/j.eist.2019.12.004.

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EPC consortium of Noor Ouarzazate II and Noor Ouarzazate III facilities in Morocco (see Fig. 5-1) and 100% of the DEWA project in Dubai.

Although early markets for CSP were highly subsidized, the markets of the future are likely to be more competitively driven, and there is stronger incentive for cost reduction. CSP needs to compete with other technologies with storage.

5.1 Parabolic Trough Project

5.1.1 Baseline Trough Plant Configuration

The current baseline configuration for parabolic trough plants is a thermal oil HTF, 6–10 hours of indirect molten-salt TES, and a power block of 50–200 MW_e. In recent years, plant sizes have trended toward the larger end of the range. Most plants have historically been wet-cooled, but newer plants are moving to dry cooling, even in relatively hot climates. Many HTFs have been considered, but the eutectic mixture of biphenyl-diphenyl oxide remains the primary fluid of new projects. Although many early plants were built without thermal storage, trough technology can no longer compete on an economic basis with PV for daytime generation. As a result, plants constructed since 2013 have included 3 hours or more of TES. Solar fields have typically been oversized to allow the plant to produce full power during the day and still charge storage so that the plants can continue operating after the sun sets. This design approach appears to be changing, and the focus is now more on collecting energy during the day and shifting generation to produce power during the night when PV power is not available.

5.1.2 Hybrid Trough Plant Designs

It is possible to hybridize trough plants to use fossil fuel as a backup or to integrate a trough solar field into other types of power plants.

Background

The SEGS plants had backup natural-gas-fired boilers or natural-gas-fired HTF heaters that allowed them to run up to full power on natural gas. The SEGS plants were allowed to use 25% natural gas input. This allowed the plants to achieve very high capacity factors during summer on and mid-peak periods. Many plants have included auxiliary HTF heaters to allow plants to start up quicker or to be able to operate at reduced loads from fuel. The Spanish FIT initially allowed plants to use 15% natural gas for auxiliary uses operation (thermal freeze protection and power-block preheating) and for production of electricity. However, this allowance was changed during the restructuring of the FIT, and fossil energy can no longer be used for electricity generation. More recently, many plants have either eliminated the fuel-fired axillary HTF heaters or dramatically downsized them to only be used for HTF freeze protection and other auxiliary purposes.

<u>ISCCS</u>: Several parabolic trough solar fields have been integrated with combined-cycle plants. These configurations are often referred to as integrated solar combined-cycle systems. The solar heat is used to augment steam from the waste-heat recovery system in the combined cycle to increase power output in the steam turbine during sunny portions of the day.

The integration of a solar field into a combined-cycle power plant results in lower capital and operational expenditures and larger annual electricity generation than a stand-alone solar power

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plant plus a stand-alone combined-cycle power plant. This is due to one larger steam turbine, steam-water cycle, generator, transformer, and switchyard, rather than two individual smaller ones. In addition, the overall thermodynamic cycle efficiency can be improved by an optimized integration of the two steam-water cycles into one.

However, the ISCC concept requires sites that are good for both—the location of the gas turbine as well as the location of the solar power plant. For example, if the ISCC plant is to be located at an optimal site for a solar power plant but a suboptimal site for a gas turbine, then the losses from the gas turbine operation at the suboptimal site can be greater than the gain from the integration of the solar field. Furthermore, the ISCC concept has only relatively small solar shares; less than 10% of the annually generated electricity can be allocated to solar generation and more than 90% is to be allocated to gas generation.

The relatively low solar share and competition from PV has reduced the interest in the ISCC concept for future plants.

Biomass: Although hybridization with biomass has been implemented in one trough plant, there is little experience with this type of hybridization. Generally, there is not a good overlap between good CSP direct normal solar resources and biomass fuel resources. There may be good niche opportunities for CSP/biomass hybrids; but generally, this does not appear to be the case.

PV: A new hybrid concept is to use electricity, potentially from PV, to heat the molten salt in the thermal storage to higher temperatures than are possible by HTF alone. This allows more energy to be stored in a TES system of a given size. It also improves the power-cycle efficiency. It requires high-temperature electric heaters for molten salt that have not been demonstrated commercially in this application. It also requires that the hot tank, hot pump, and hot-salt piping operate at higher temperatures and be changed from carbon steel to stainless steel. The steam-generation system will be salt to steam, similar to the molten-salt tower.

Best Practice

- Hybridization offers trough technology the opportunity to have high availability and be able to produce power during cloudy periods when other solar technologies, such as PV plus batteries, would not be able to generate. The hybrid SEGS III–VII plants were able to deliver in excess of 100% on-peak capacity on a monthly basis for over 15 years running.

5.2 Parabolic Trough Collector Technology

5.2.1 Collector Designs

The desired features of parabolic trough collectors are to maintain high availability and reliability, have good optical and thermal performance, have a stiff structure to maintain optical performance, be strong enough to survive wind and earthquake loads, have low maintenance requirements, and have a low initial cost. It is important to balance not only initial quality control and cost, but also, longer-term O&M costs.

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Background

Significant advances in trough technology have occurred over the last decade. Generally, new collector designs have been attempting to reduce costs. This has led to larger sizes, optimized structures to reduce steel content, reduced part and fastener count, improved manufacturing process, and designs that reduce onsite labor requirements. Mirror quality has improved, allowing new larger collectors to go to higher concentration factors while maintaining optical performance. This allows smaller-diameter and cheaper receivers to be used. In addition, collector designers have developed a better understanding of wind loads; and collector structural design, new analytical tools, and testing capabilities allow designers to create new collector designs that can be optimized for cost and optical performance.

The three primary collector structural designs used by most recent commercial projects are: torque tubes (Sener Trough, HelioTrough), torque box (EuroTrough, Ultimate Trough), and space frames (Gossamer, E2, SpaceTube). All these designs have advantages and disadvantages. All are potentially capable of operating well for use in a project. However, poor implementation of any design could result in significant performance and availability issues for a project. Delivering a cost-effective, well-performing collector is not as simple to get right as might first appear. It is important to have an experienced provider and to make sure there is a rigorous quality control and quality assurance process during all stages of design, procurement, assembly, installation, commissioning, and operation.

The industry appears to be able to supply solar fields capable of achieving very high availabilities and generally meeting expected initial performance and degradation assumptions.[14] All parabolic trough plants visited during this study had solar-field availabilities above 99%.

Trough collectors focus highly concentrated light onto the receiver, but this concentrated light is sometimes blocked either by the steel structure supporting the receivers or near the drives. This steel can potentially reach excessive temperatures, even higher than the HTF temperatures (because the metal is not being actively cooled by HTF passing through it). As a result, galvanized steel will experience accelerated corrosion rates. This issue needs to be considered in the collector design and during operation of the plant.

Best Practices

- It is important to have solar technology providers who are experienced and have a good track record of delivering a quality solar field on budget and on time.

- Make sure an appropriate QC/QA process is used to confirm the quality of collectors delivered.

5.2.2 Collector Design Wind Loads

It is important that collectors be designed to survive wind conditions at the project site.

[14] Note this does not consider the receiver hydrogen issue discussed in Section 5.2.5.

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Background

As a rule, building codes are not particularly applicable for determining the structural requirements for trough collectors. In addition, no design standards exist for how to take a wind speed and convert it to loads on the collector. Currently, there is no consensus among collector suppliers in the industry on how this should be done. As a result, it appears that every trough collector supplier uses its own approach.

EPC companies also often lack an understanding of this issue and cannot fairly compare collectors that may be designed to different wind loads. Some collector suppliers complain that because they design their collectors appropriately, it puts them at a disadvantage to others who have under-designed their collectors, using less metal. In general, collectors appear to have been adequately designed to survive the wind conditions at most plant sites; however, a couple notable problems have occurred in operating plants where collectors have been under-designed. So, some bidding processes have increased the design wind speeds to make sure that the collectors that are bid will be strong enough. But then, suppliers who design their collectors appropriately end up with over-designed and more expensive collectors.

Every project should conduct a wind study for the plant site to make sure there is an understanding of the site-specific weather conditions. A specific site may be exposed to higher wind speeds than the region as a whole. Depending on the wind study, different collector designs could be preferred. It is important to determine the best wind-protect stow position for the collector. Many collectors have been stowed at 30 degrees below the eastern horizon. Wind tunnel studies have shown that this is not necessarily the orientation with the lowest loads. Studies have indicated that minimum loads may be between minus 10 and plus 10 degrees. Typically, the lowest loads occur when the collector is facing into the wind. So, it could make sense to have collectors on the east side of the field stow to the east and collectors on the west side stow to the west.

CSP plants report experiencing two general types of wind events. The first type is a large-scale event that the entire plant experiences. This is due to general macro weather conditions, where the entire plant sees high wind speeds. In this case, collectors at the perimeter of the plant and in exposed areas interior to the plant see the highest loads. Collectors in the middle of the field are shielded by the collectors surrounding them and see reduced loads. There are three general approaches for addressing these types of wind events: (1) build stronger collector structures around the perimeter of the solar field and in exposed areas; weaker or cheaper collectors can be built in more-protected locations; (2) install wind fences at exposed edges of the field, and (3) build all collectors strong enough to survive the design wind speeds. The approach taken will depend on the size and layout of the plant and the risk profile of the site.

The second type of wind events reported are localized events experienced in only a small section of the solar field. These events may be cyclonic/tornado types, dust devils, or microbursts. A microburst is a strong downdraft that typically occurs during or near a thunderstorm, and it tends to be somewhat dependent on location. Locations that experience summer monsoons and thunderstorms may be more susceptible to these types of events. Clearly, perimeter shielding will not prevent damage from these types of events. Areas prone to these events should consider making all collectors stronger. The site-specific wind assessment should identify if these

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localized wind events are likely to occur. Some locations do not report these events at all or only rarely, whereas other sites indicate that they can occur many times a year.

Generally, wind damage has not been reported as a major source of availability loss at most plants. However, one plant experienced a major wind event that damaged about 15% of the collectors. Several plants have reported damage during construction when collectors were more exposed as the solar field was being built out. Some plants report damage occurring from small localized wind events.

Many participants indicated that wind fences do appear to protect the perimeter of the field from damage. For a wind fence to work, it should have some porosity—about 50% porosity is assumed to be appropriate—to help slow down the wind. The fences should be a minimum of 75% of the height of the collectors, and within two or three aperture widths of the collectors. However, several participants noted that solid earthen berms do not work the same as a wind fence. Berms may direct the wind over and back down onto the collectors further into the field. There is also some concern that berms may channel the wind, creating wind tunnels that result in increased damage to mirrors at the ends of collector rows.

It is important to have a good understanding of the wind conditions and patterns that are likely to be seen at the site. The plant needs to create a high-wind operating strategy for the solar field. Each site could be different depending on the prevailing wind directions and the type of high wind-speed patterns. In some cases, the maximum wind conditions do not occur from the prevailing wind direction. Collectors are typically more vulnerable in some orientations than others. The face-up orientation is typically the most exposed and dangerous. So, decisions as to what direction to stow the collectors may depend on the position of the collectors when they are being sent to stow. Most fields normally stow collectors to the east, so they are quick to send to operate in the morning. However, collectors with western exposures may want to be stowed to the west.

There is a maximum wind speed that the collector can withstand depending on the orientation of the collector. Collectors must be sent to their wind-protection stow position at a sufficiently low wind speed to make sure that they can get to the stow position before the wind speed increases to a point that it exceeds the maximum operating wind speed in any orientation prior to getting to the wind stow position. The maximum speed of the collector and the time required in any orientation to move to stow needs to be considered. It is important to have an idea of how quickly the wind speed typically increases to determine at what wind speed the stow alarm is triggered. The maximum operating load of the drive may be less than the collector and needs to be considered.

Several participants noted that Typical Meteorological Year performance model runs did not indicate any loss due to high wind conditions that required the solar field to be stowed. But every year, some loss of availability occurs because the solar field must be stowed for windy conditions, often in the range of 1%–2% loss of availability. Solar fields must usually be stowed due to 3-second peak wind speeds, but TMY data usually only include hourly average wind speeds. During project development, a more detailed analysis of the potential impact of high winds should be conducted to understand the potential impact on performance. It is our understanding that actual high-wind-protection stow events typically trigger based on peak wind

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speeds (3-second gust data). But TMY data typically only include hourly average data. It is not possible to correlate hourly average wind speed to gust wind speeds. For this reason, a more detailed wind analysis is required that considers wind speeds on a finer time increment. We recommend that wind analysis uses a 5- to 10-minute time increment that considers both the maximum 3-second gust and average wind speed over the time increment.

Windy conditions can also impact the optical efficiency of collectors. Wind can cause increased torsion and movement of the collector around the rotation axis. This has a notable impact on the collector's optical efficiency as the wind speed increases toward the maximum operational wind speed. Depending on the design of the collector, specifically the torsional stiffness, wind will have more or less impact on optical efficiency.

Performance/guarantee models should account for the wind impact on collector optical efficiency, receiver thermal losses, and collector wind-stow events.

Best Practices

- The industry needs to work together to develop appropriate collector design standards that can take a design wind speed and convert it to design wind loads. The standard should also describe how those loads are used to appropriately size the structural members in the collector. The standard should provide guidance on wind-tunnel testing.

- Developers should conduct a detailed wind study at the site to determine the actual maximum wind speeds that are likely to be expected and if any abnormal wind-type events occur at the site that should be accounted for. The results of this study should be used to set the design wind speed for the site and help determine other issues such as the appropriate wind-stow speeds.

- Care should be taken to make sure the collectors selected are designed appropriately for the wind speeds that will be experienced at the plant site.

- A wind fence may be considered on all sides of the plant and around any open exposed areas on the interior of the plant (e.g., around the power block) depending on site conditions, the size and layout of the solar field, and the collector design. Wind fences should have about 50% porosity and be at least 75% as tall as the collector and within two or three aperture widths of the collectors.

- It has been noted that the normal stow position for trough collectors—30 degrees below the eastern horizon—may not be the best orientation to minimize loads on the collector. It is important to have the collector vendor determine the best stow orientation for high-wind conditions. This could be site-specific, depending on prevailing wind direction. So, participants have indicated that the best wind stow position for the collectors may be between -10 degrees and +10 degrees. It is also noted that it may be best to have collectors with western exposures stow to the west.

- Make sure initial performance projections appropriately account for lost efficiency and availability due to stow events for high-wind conditions. It is important that the performance guarantees and performance model reflect with the same wind-protection

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strategy that the plant used in practice. We recommend that performance calculations be done for shorter than hourly time steps, ideally 5- to 10-minute time steps. Resource data should include both an average wind speed over the time step and the maximum 3-second gust speed during the time step. Thermal losses and optical losses will be based on the average wind speed, and stow triggers will be based on peak wind speeds and/or average wind speeds, depending on actual wind-protect operating strategy.

- Typically, plants only have one or a few anemometers to measure the wind speed at the site. Wind velocity is not uniform across the solar field, so these instruments will likely not measure the maximum wind speed seen at the site. Some level of conservatism is needed in using these data for operational decisions.

- Typically, wind-speed triggers for collectors have been at a single wind speed. However, collector designers should provide a wind-stow trigger speed and stow direction depending on the orientation of the collector. This may allow collectors to operate in higher wind speeds in some orientations before having to go to stow. Additionally, the stow wind speed is a function of how quickly the wind speed is assumed to increase. The collector provider can provide different wind-stow speeds based on how quickly peak wind speeds are assumed to increase.

5.2.3 Collector Optics

Not all collector designs perform the same optically. The differences between well-designed collector optics and a poor design can be significant, leading to the conclusion that optical performance of the collector should be an important consideration in the selection process. Collector optics, which can be a critical part of the long-term performance of a plant, is an issue of which most CSP participants have very limited understanding.

Background

In recent years, significant advances have been made in the knowledge and tools available for assessing collector optics. A much better understanding of potential optical issues has been developed by collector providers, research organizations, and specialized testing companies. The capability exists to do 100% QC on collectors coming off the assembly line. Participants indicated that drone-based optical assessment tools now exist that could allow 100% QC on collectors as they are installed in the field. In theory, these same tools can be used for periodic inspections to monitor the optical performance of the collectors over time.

It makes sense for design purposes to have the collector providers perform the QC process during assembly and installation of collectors. However, there should be independent QA of the process both in the collector factory (assembly hall) and after the collector is installed in the solar field. Experienced companies can perform these services for projects, and this process should be included in the OTS and EPC contract.

Many participants noted a lack of optical standards for parabolic trough collectors. This is an area deserving attention by industry and the research community.

Each collector design has a unique incident-angle modifier (IAM) that should be provided by the collector provider. The IAM defines the change in collector optical performance as a function of

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the sun incidence angle. When the sun is directly overhead (an incidence angle of zero), the collector has one optical efficiency. In this orientation, the IAM is assumed to be 1.0. As the sun's incidence angle changes, the IAM will change due to changes in the receiver absorptance, transmittance and absorption of the receiver glass envelope, bellows shading, blockage from receiver supports and collector structure and drives, mirror gaps, mirror reflectance, and other factors. The IAM is difficult to calculate accurately and typically needs to be measured with thermal efficiency testing in the field.

Best Practices

- Consider whether it makes sense to do 100% QC of collectors as they are assembled and 100% QC of collectors as they are installed in the field. Have an independent QA of this process.
- Conduct periodic sampling inspections of collectors over time to trend solar-field optical performance and identify collectors that may need attention. New drone-based systems may be able to provide quick assessment of collectors to identify trends and specific collectors with problems.

5.2.4 Receivers—Reliability / Breakage

The parabolic trough linear receiver, also referred to as a heat-collection element (HCE), is the key to the thermal performance of modern parabolic trough plants. Major improvements have been made in the reliability and thermal performance of today's commercial receivers. Receiver reliability and lifetime are still important issues, and some practices appear to help minimize failures.

Background

In early years, receiver failure rates (breakage of the glass tube) of 2%–8% per year were experienced.[15] Improved design, installation, and operation have greatly reduced these types of failures at modern plants. This reduction in the range of failures is consistent with reports from independent sources. According to participants who monitor the O&M at many of the newer plants, receiver breakage rates are between 0.1% and 0.5% per year. However, there have been some exceptions.

The main causes of receiver glass-envelope breakage are mirrors breaking and falling on the receiver, torque from ball joints, and operational problems. The main operational problem appears to be related to minimum HTF flow or the buildup of non-condensable gases that may interfere with good HTF flow. Minimum HTF flow or buildup of non-condensable gases will result in lower heat transfer and thereby cause circumferential asymmetric overheating of the steel tubes; this will cause the tubes to bend and eventually touch and break the glass envelope. One plant indicated that a relatively high failure rate occurred during commissioning because the solar field was tracking with low HTF flow. Another plant indicated that it had experienced a nitrogen bubble, which caused about 5% of the receivers to bow and break the glass envelope. Finally, one plant experienced 1% receiver breakage during a wind event. In this case, the

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[15] H. Price, M. J. Hale, R. Mahoney, C. Gummo, R. Fimbres, R. Cipriani, "Developments in High Temperature Parabolic Trough Receiver Technology." Paper ISEC2004-65178, NREL/CP-550-35734, 2004.

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receiver glass envelopes were broken, which was caused by breaking mirrors or structural damage to the collectors themselves; there was no leakage of HTF.

Receiver damage can occur after repair work has been carried out by introducing hot HTF from the headers into the cooler pipes of an emptied loop. The hot HTF only flows in the lower area of the cooler empty absorber pipes and creates extreme temperature differences across the pipe circumference, which can lead to bending and glass breakage. This problem must be taken very seriously, and care should be taken to adjust the receiver and HTF temperature (e.g., filling with cooler HTF from a mobile tank) or filling the receivers at night when the bulk HTF temperature is well below normal operating temperatures.

It is very important to make sure receivers are installed properly to ensure they have proper alignment. Receivers must be covered to prevent direct heating from the sun and must be welded correctly. Care must be taken to avoid torsion and beam loading from ball-joint assemblies or other interconnection approaches.

At least one source claims that partial defocus tracking may cause some receiver glass-envelope failures. A ray-tracing analysis shows that small defocusing angles with high incidence angles of the beam solar radiation can produce a solar flux onto the inside of the bellows and glass-metal seals that can be damaging to some older receiver designs. There is some concern that HTF temperature control by means of partial defocusing has significantly increased the breakages of receiver tubes. Others have indicated that this appears to be a good approach and have not indicated any issues with receiver failures. HCE manufacturers are aware of this problem and have introduced new designs that have improved internal shielding to protect the glass-metal seals and bellows from concentrated solar flux.

There is concern that operation on partially cloudy days may be an issue, when flows are reduced to drive up the outlet temperature. Some loops may be seeing full concentrated sun at low flows. This may also be an issue when plants with TES have fully charged the TES. They are forced to operate the field at reduced flows, so if they use the collector defocus tracking to manage the temperature of the HTF, they may be running low flows with high concentrated solar flux.

The main action that can be taken to reduce HCE failures appears to be to maintain higher minimum HTF flow rates in the solar field. Nevada Solar One only experienced 0.3% receiver failures over the first 10 years of operation. They maintain a higher minimum HTF flow rate—about 50% of design flow, which is higher than typically appears to be used at other plants—and use a more gradual temperature ramp-up of the solar field each day. This plant does not have TES, and thus, it may have more flexibility than plants with TES.

Additionally, non-condensable gases and steam can build up in HTF piping. This can potentially interfere with HTF flow or impede heat transfer to the HTF, resulting in overheating and potentially bowing of receivers to the point that the glass is broken.

Ball joints can bind up and cause a significant increase in the torque applied to the receivers. This torque can cause the receiver tubes to bow and break the receiver glass envelope. Some collectors have two receiver supports at the end of the collector, usually separated by 0.2–0.3 meter. This configuration seems to reduce the bowing induced in the receiver by the ball joints,

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and it may reduce receiver breakage at this location. It is important that proper alignment and care be taken to make sure the ball joint does not add loading when it is installed.

Finally, it has been noted that good loop flow balance is important. Low HTF flow conditions are aggravated by lower flow in unbalanced fields. If the flow is too low, then cracked HTF builds up in the tube, which makes the situation increasingly worse. Similarly, flow balance between fields is important to make sure all fields have adequate flow. It was noted that it is important to have good field flow control valves with automatic positioners at the inlet to each field so that the flows can be balanced automatically between fields.

Best Practices

- Make sure the high points in HTF piping are periodically vented of non-condensable gases. The goal is to avoid any entrainment or buildup of gases in the HTF that flows through the collectors.

- Maintain higher minimum HTF flows in the solar field when tracking the sun. Make sure the HTF flows are well into the turbulent region. Consider maintaining higher HTF flows on partially cloudy days.

- It is important to have a QC process to make sure receivers are installed using the correct procedures. It is important that when receivers are welded together, the glass envelope is covered with the foil covering that the receivers are shipped with. This helps to ensure that the receivers are not welded in with the tubes already bowed.

- Collector designs with two receiver supports at the end of the collector appear to protect the receiver better against ball joints torqueing the receiver and breaking the glass. It is important to make sure the pipe and receiver supports are properly aligned and that the ball-joint assembly is installed correctly such that it does not cause the receiver to bend and break the glass.

- Make sure receivers have bellows shield coverings that completely cover the bellows and glass-to-metal seals on the receiver tubes at all sun angles. Ideally, these coverings should be supplied by the receiver vendor to make sure there are no warranty issues. These should provide adequate protection to prevent concentrated light from internally heating and damaging the bellows or glass-to-metal seal, especially when the collector is partially defocused.

5.2.5 Receivers—Reliability / Hydrogen

The parabolic trough receivers have a vacuum between the steel and glass tubes (referred to as the receiver vacuum annulus) that helps to minimize thermal losses from the receiver. Hydrogen can permeate from the HTF through the steel tube into the vacuum space. If hydrogen builds up in the vacuum space—on the order of 1 mbar partial pressure—then thermal losses can increase by a factor of 3 to 4 times.[16]

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[16] Frank Burkholder, "Transition Regime Heat Conduction of Argon/Hydrogen and Xenon/Hydrogen Mixtures in a Parabolic Trough Receiver," PhD dissertation, University of Colorado, 2011.

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Background

In recent years, a number of operating plants have started experiencing hydrogen buildup in the receiver-tube vacuum annulus. Hydrogen is produced from the normal breakdown of the HTF. Receivers are supplied with getters, which are small pills of a special material designed to absorb hydrogen or other gases in the vacuum space. Unfortunately, getters are expensive and have a limited capacity to absorb hydrogen. Hydrogen is a small enough molecule such that it can pass from the HTF through the stainless-steel tube into the vacuum space. If the getter fills up, then hydrogen will start to build up in the receiver vacuum space until it comes to an equilibrium with the hydrogen partial pressure in the HTF. In theory, the receivers were supplied with a sufficient amount of getter material to give the receivers a 25- to 30-year useful lifetime. However, this design assumes a maximum hydrogen partial pressure in the HTF (30 Pa). It now appears that the amount of hydrogen in the HTF may be one or two orders of magnitude higher than originally assumed. (It appears to be very difficult to measure the partial pressure of hydrogen in the HTF.) The result is that receivers in many operating plants appear to be showing signs of hydrogen buildup in the hottest receivers in the plant.

As noted above, hydrogen can permeate through the stainless-steel tube into the vacuum space. It only takes a small amount of hydrogen to become a problem because hydrogen gas is a very good heat-transfer medium and increases thermal losses to the glass envelope. With as little as 1 millibar, which is 1 thousandth of atmospheric pressure—the thermal losses in the receiver can increase by a factor of 3 to 4—from about 200 W/m of receiver length to about 800 to 1000 W/m. This has a significant effect on the overall efficiency of the receiver tube. A drop in output of about 10% could occur if all the receivers in the hottest collector in the loop have hydrogen present.[17]

The problem starts at the hottest receiver tubes and over time (years) progresses backwards around the loop to the colder receiver tubes. The main reason for this pattern is that the hydrogen permeability of the stainless-steel tube decreases at lower temperatures. Thus, the hydrogen buildup takes longer in colder receivers.

Many plant operators seem somewhat unaware of whether they have an issue with hydrogen buildup. The confusion may be over whether the problem exists or confusing the problem with a loss of vacuum, where air is present in the annulus.

The SEGS plants detected a problem with hydrogen in the 2003–2005 timeframe. Receiver vendors addressed the problem by increasing the amount of getter material in the vacuum space and making other design changes to the receivers. These changes were assumed to address the problem. The SEGS III–IX plants replaced most of their receivers in the 2007–2009 timeframe with the newer improved receivers and assumed that this would address the problem.

As of 2019, the Nevada Solar One trough plant has been operating for about 13 years. It was one of the first operating plants to recognize the hydrogen issue with the newer-style receiver tubes. The issue, first noticed after about seven years of operation, was initially detected due to a slight drop in plant output that could not be attributed to any other cause. Hot receiver tubes were then

[17] Based on field test results from Nevada Solar One.

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detected on the hottest collectors. Hydrogen has now worked its way around the collector loop and has started to affect the hottest collectors on the cold half of the collector loop.

The SEGS III–IX plants all appear to have hydrogen present today, but it is not known to what extent. However, public data show that the performance initially increased after the receivers were replaced; but in recent years, the performance from the plant has again decreased significantly.[18] Most of the performance loss is due to hydrogen in the receivers according to the operator of SEGS VIII and IX.[19] In one plant with very degraded HTF, new receivers started showing signs of hydrogen after only two years of service in the hottest collectors.

By some accounts, many of the trough plants in Spain have started experiencing the hydrogen problem.

The degradation of HTF is a function of the fluid operating temperature. According to the manufacturers' data, a significant reduction in HTF degradation can be achieved by reducing the maximum operating temperature of the HTF by even 5°C–10°C. The hydrogen production rate appears to be a function of degradation state of the HTF, with degradation products producing more hydrogen than good HTF. Maintaining low levels of low and high boilers, which are HTF degradation products, is likely one way to minimize hydrogen levels in the HTF.

It is noted that not all receivers are affected at the same rate, with some receivers showing signs of hydrogen buildup before others. This is likely due to the different design approaches used to address hydrogen. The type of steel used, the presence of a hydrogen barrier coating, and the quantity and location (and hence, the temperature) of the getters likely have an impact.

The original LUZ receiver tubes used at SEGS VI–IX included a palladium membrane that was used to remove hydrogen from the receiver annulus to the atmosphere. The palladium membranes, referred to as a hydrogen remover, had some reliability issues and were not used in later replacement receiver-tube designs. The membranes were prone to corrosion and cracking, which allowed air into the vacuum annulus or, in some cases, caused the glass envelope to crack. An infrared survey of the SEGS plants in 2005 found that many of the receiver tubes tested (about 15–17 years after the receivers had originally been installed) indicated that they still had good vacuum in the receiver. The hydrogen-remover concept might be considered for future receiver designs.

The easiest way to inspect a solar field for the hydrogen problem is to use an infrared camera or infrared gun to measure the receiver glass temperature. The receiver glass temperature will go up by about 70°C if hydrogen is present at a level to increase heat losses. It is important to measure the receiver when it is on-sun tracking at full operating temperature; if this is not the case, results may be misleading. The getter material is temperature sensitive and can hold more hydrogen at even slightly lower temperatures. Thus, if a collector is defocused to take measurements, the problem may not be observed in some tubes that normally have hydrogen present.

[18] Based on publicly reported performance data from NERC.
[19] The cause is known to be hydrogen due to elevated receiver glass temperatures.

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The German Aerospace Center (DLR) has developed a procedure for measuring the hydrogen partial pressure in HTF.[20] The process requires a special sampling procedure and small suitable containers to make sure no hydrogen is lost before the sample can be measured. One participant mentioned that most plants do not have HTF sampling stations included. Some relatively minor piping modifications may be required to allow HTF samples to be taken appropriately.

DLR has done tests that indicate that the hydrogen levels in the HTF can be reduced by increased venting of the nitrogen headspace gases in the expansion tank. It may be necessary to adapt the expansion system design to spray HTF into the tanks to encourage hydrogen to come out of solution. To our knowledge, this has not been demonstrated long term, but may be a partial solution to the hydrogen problem. Note that this approach has other implications: this will significantly increase the amount of nitrogen used by the plant; the ullage system would be used more frequently, which may have implications for increased carbon-filter usage; hazardous-waste generation (contaminated carbon filters); and there could be permitting considerations due to increased ullage-system operation and emissions.

The National Renewable Energy Laboratory (NREL) is developing a system that can remove hydrogen from the headspace gases in the expansion vessel. These techniques are discussed further in the HTF System section of this report under the Ullage System topic.

The options for tubes that already have hydrogen present include:

- Replace the tube with a new tube. This immediately restores the performance, but this is only a temporary solution if the hydrogen level in the HTF is not also reduced.

- A procedure has been developed for injecting a small amount of argon into the receiver vacuum annulus. This interrupts the hydrogen heat transfer and reduces the incremental hydrogen thermal losses by about 80% to 90%. This has been demonstrated at the Nevada Solar One project with good success. The retrofit process can be done with the receivers installed in the field with HTF circulating through them. This is assumed to be a permanent solution.

- Attempts have been made to re-evacuate the receiver. This has proven to be possible, but in this initial testing, it was shown to be quite complex and to take a significant amount of time. We presume that if more development occurred, this process could be further optimized. Again, this is only a temporary solution unless the underlying hydrogen in the HTF is also addressed.

- NREL has proposed that by reducing the partial pressure of hydrogen in the HTF to very low levels, it is possible to reverse the process and pull hydrogen from the receiver and back into the HTF. This has been demonstrated at laboratory scale, and a pilot-scale

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[20] Christian Jung, Marion Senholdt, Carsten Spenke, Thomas Schmidt, and Steffen Ulmer, "Hydrogen monitoring in the heat transfer fluid of parabolic trough plants," AIP Conference Proceedings 2126, 080004 (2019); https://doi.org/10.1063/1.5117599.

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

system demonstration is currently being tested at an operating plant. If successful, it could be an important solution to help address the hydrogen issue.

HCE manufacturers are aware of the problem and some have addressed the problem by requiring the partial pressure of hydrogen in the HTF to be maintained below 30 Pa in their warranty. However, most plants are not being designed and operated to maintain hydrogen in the HTF below this level.

Best Practices

- New plants need to be designed and operated to maintain hydrogen at levels required to maintain receiver performance for the design life of the plant. This will require a more in-depth design process to account for HTF degradation versus operating temperature over the life of the plant.

    - A well-designed and operating ullage system is key and should include a system that removes both low and high boilers from the HTF. This has implications for increased HTF replacement rates because it is often not possible to separate all the HTF from the high boilers.
    - Consider designing the plant to operate at lower peak HTF operating temperatures. Even a relatively small reduction in operating temperature (5°C–10°C) could significantly reduce the problem. The design should optimize operating temperature versus HTF degradation and HTF replacement rates. The temperature control of the loops should be optimized to avoid excess temperatures at the loop ends.
    - Venting of the nitrogen in the HTF system can remove hydrogen in the HTF. We do not believe that this will be enough to maintain hydrogen at appropriate levels by itself, but it could be important in combination with other changes. This will likely significantly increase the amount of nitrogen consumed in the plant.
    - Installing a system to remove hydrogen from HTF system headspace gases in the expansion vessel or other appropriate locations could be an alternative to venting nitrogen.
    - New plants can also consider installing receivers with argon to reduce the future risk of hydrogen buildup in receivers. The solar field can be oversized to compensate for increased thermal losses (about 2%) to compensate and eliminate the future risk. The cost of receivers may be reduced, as well, due to the reduction in the amount of getter material required and potentially switching to cheaper steels.[21]

- For existing plants:

[21] The selection of ASIS 321 has been based in part on its hydrogen permeation rate. It is possible that cheaper steels can be used but will depend on many factors such as "corrosion behavior", "material strength" and "reliable application of the selective coating".

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- The ullage systems should be operated to maintain high boilers at appropriate levels. Many plants do not appear to be using their ullage systems to remove high boilers.
- Annual[22] monitoring (or sampling) of receiver glass temperature can monitor the progression of the problem. Start at the hottest receivers. This can likely be done with drone-based infrared systems. Ideally, testing should be done with the collectors tracking when the plant is operating close to design temperatures.
- Venting or an expansion-system headspace-gas hydrogen removal system can also be considered.
- For receivers that are already affected by the hydrogen problem, an argon injection retrofit can be used to reclaim most of the lost performance. However, no commercial service for this is currently available.

- All plants should already monitor HTF fluids for low and high boilers with their routine HTF sampling. We believe the high boilers are likely most indicative of the status of the HTF. This is something easy to monitor. High boilers are a measure of the breakdown products. As the HTF degrades, hydrogen is released in the breakdown process. More breakdown products likely mean more hydrogen generation. It would be best to test the fluid several times a year.

5.2.6 Mirrors—Reliability

The mirrors used in parabolic trough plants are typically 4-mm low-iron glass, with silver on the back surface and protected with a 3-layer paint coating. The paints used in the SEGS plants had a high lead content. Some early versions of the paint did not hold up, but eventually, a good multi-layer paint system was achieved, and these paints lasted well but had environmental considerations. Newer paints use either no-lead or low-lead paints. There is less experience to know whether they will hold up for 30 years like the later SEGS mirrors.

The initial mirrors used metal pads glued to the back of the mirrors to mount the mirrors to the collector structure. There were many mirror-pad failures in early plants attributed to the glues used and different expansion coefficients between the metal pads and the mirrors. The problem was aggravated by the metal mirror pads being exposed to direct sunlight when the collectors were stowed for maintenance. The metal pads would get significantly hotter than the glass mirrors. Mirror manufactures switched to white ceramic mounting pads, which appeared to solve the mirror-pad failure issues.

Some failures occur at the perimeter of the fields due to high wind conditions. When the glass breaks in a receiver tube, it can also break the mirrors below it. The other common cause of mirror breakage is due to O&M activities (usually interference with the mirrors by mirror washing or other maintenance activities in the solar field).

[22] More frequent monitoring is desirable, but it is a tradeoff of manpower and cost. Aerial drone-based measurements could make more frequent monitoring feasible.

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Mirrors are of two general kinds. The original mirrors were a 4-mm annealed-glass mirror. More recently, several manufacturers are supplying 4-mm tempered-glass mirrors, which appear to be stronger and have lower breakage due to wind events. But some mirrors still break due to rocks kicked up by passing O&M vehicles. Additionally, one mirror manufacture used laminated glass like the glass used for automobile windshields; these mirrors had some advantages and disadvantages over other designs, but they may no longer be available.

In general, mirrors have proven to be very robust. Some of the SEGS projects in California reported annual failure rates of 0.2% after almost 30 years of operation. Projects in Spain have experienced reflector panel breakage of 0.05%–0.15% per year during normal operation.[23] These values could be higher during construction and commissioning phases.

Best Practices

- 4-mm tempered-glass or 5-mm annealed-glass mirrors are installed in high-wind locations (i.e., field perimeters and along the power block or other exposed areas in the field) to reduce breakage.

- Some collector designs need the mirror supports to have cross braces to prevent mirrors from moving during windy conditions and hitting other mirrors.

5.2.7 Mirrors—Cleanliness

Cleaning of mirrors is an essential part of the O&M of parabolic trough plants. It is one of the easiest ways to affect the performance of the plant, although it often does not get the attention it deserves. For large plants such as Solana, Mojave, Noor Ouarzazate I/II, and DEWA, maximizing mirror cleanliness across the solar fields is a major optimization effort.

Two general approaches of cleaning are used. The first method is a demineralized water spray, which can be done at high pressure (200 bar/3000 psia) with low water volume, or with a deluge with low pressure but high water volume. The second method is to use a mechanical cleaning (or scrub wash) with some form of brushes mixed with a high-pressure spray. Mirrors can be washed by hand or by vehicles that have been specially designed for the task. Vehicles obviously offer much more rapid cleaning, but some vehicle-mounted machines have been reported to have reliability issues. Hand washing is hard work and will take a much larger staff to clean mirrors at the same rate as vehicles.

Today, there are many more suppliers of specialty mirror-cleaning vehicles than there were even a few years ago. The growth in the number of large PV solar projects, which also have cleaning needs, has benefitted CSP plants, as well. However, not all cleaning vehicles appear to be of similar capabilities and quality. There appears to be a wide range in cost, and some have experienced significant reliability and availably issues.

Mirror soiling rates are largely site-dependent. Different areas have different soil characteristics that will have different soiling rates and could be easier or more difficult to clean mirrors.

[23] Failure rates provided by independent engineering firm responsible for monitoring the O&M of many trough plants in Spain and other regions.

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Humidity, dew, and frost can make soiling worse or make mirrors more difficult to clean. Dry climates may make it easier to clean mirrors but may have higher soiling rates due to increased dust in the air. Furthermore, soiling rates typically vary dramatically by season.

One of the most problematic soiling issues occurs when dew forms on the mirrors at night and this dew traps the dust from the air. The dew binds practically all dust that touches the mirror, and when the dew dries, the dirt sticks to the mirrors like cement. The lower row of mirrors at stow-position is most affected because on the one hand, it can hold the most dust due to its position, and on the other hand, it forms the most dew.

Rain and snow can be excellent for cleaning mirrors. Collectors can be faced up during a rainstorm to get a good cleaning. However, a small amount of rain may only remove the dust from the atmosphere and deposit it on the mirrors. Therefore, the rainstorm needs to be of sufficient magnitude to rinse the mirrors well. A small amount of snow (~5 cm) when the air temperature is slightly above freezing can also be used to clean mirrors very effectively. Very cold snow may simply stick to the mirrors. Care must be taken to make sure snow loads do not exceed the structural design of the collector.

Many plants have experienced a high soiling event, which often occurs with high winds, hot temperatures, and when a small amount of rain falls. This may be caused by a thunderstorm passing but with only a small amount of rainfall. The end result is that mirrors may get dirt that is wetted and dried on the mirrors. Some plants have reported mirror reflectivity that drops from above 90% cleanliness to cleanliness around 50%. At most sites, these events are rare; however, they can have a huge impact on annual performance because it can literally take months to recover if the plant is not prepared. One project has developed a rapid-cleaning response plan so that they are prepared for the next time one of these events occurs at their plant. This plan mobilizes additional staff and cleaning units to clean the mirrors. They have figured out alternative mirror wash approaches that may not work as effectively as their regular wash systems but allows them to recover much of the lost reflectivity much quicker. One approach is what the SEGS plants referred to as a “deluge wash.” This is simply a water truck spraying a high volume of demineralized water on the mirrors.

Projects need to decide whether they will self-perform cleaning or contract it to others. Projects have reported success with both approaches, but also lack of success with both approaches.

Monitoring of mirror cleanliness

It is important to be able to estimate mirror cleanliness so as to assess plant performance and to help develop an optimized mirror-cleaning strategy. One must understand both the variation of mirror cleanliness across the plant, as well as how soiling rates vary across the plant and during the year.

Several tools can be used to make field measurements of mirror reflectivity and track mirror cleanliness. Abengoa has developed its Condor, which is a simple and robust device for measuring mirror cleanliness. The D&S Model 15 R portable specular reflectometer has been around for more than 30 years and continues to be a robust and simple tool to use for this purpose.

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However, either device only measures a small area on a mirror at a time. So, a cleanliness sampling method needs to be developed to estimate the average cleanliness of the entire plant. Some plants put considerable effort into the cleanliness calculation. One plant takes three readings at 84 locations to determine an average field cleanliness. They use a statistical approach with readings at different locations each time they take measurements, and they do this every two days. It is a large plant, so it requires much effort just to get an estimate of average mirror cleanliness. However, they also use the data to help prioritize mirror cleaning.

Some difference of opinion exists among projects as to the value of measuring plant cleanliness and soiling rates. This seems to be related to the soiling rates experienced at the plants: sites with low soiling rates seem less concerned, whereas sites with high soiling rates seem most concerned.

Best Practices

- Install mirror samples and perform a soiling evaluation campaign at the plant site before plant construction to assure that soiling will not be a significant problem at that place.

- Anything that can help make mirror cleaning easier and quicker is probably worth doing if it is effective.

- A general best practice is to use demineralized or reverse-osmosis water to clean the mirrors. In most cases, no cleaning agent is required or desired, and water should not be heated.

- Mirror cleaning should be done at night. Daytime cleaning risks damage to receivers and damage to cleaning personnel and equipment due to stray concentrated sunlight.

- Projects need to plan for adequate mirror-cleaning water supply and the associated water-treatment requirements during the design of the plant. This could include water storage tanks, and potentially, water supply to remote wash-vehicle fill stations. Large fields require considerable logistics, and generally, the mirror wash rigs move very slowly. If logistics are not thought out carefully, then numerous hours will be spent driving back and forth to supply water.

- Plants should consider purchasing specialty mirror-cleaning vehicles. Several companies now provide specialty vehicles for washing parabolic trough mirrors. Choose vehicles that have demonstrated good availability and cleaning performance and that are supported locally and from a reputable supplier to make sure spare parts and service are likely to be available in the future.

- Plants should consider having wash vehicles that high-pressure water spray or deluge (high-volume spray) mirrors and have wash vehicles that can scrub mirrors. The exact mix of the types of vehicles will depend on the mirror soiling conditions at the project site and will likely change during different times of the year. In some locations, scrub washing is only needed infrequently and can be done by hand. In other locations, having vehicles with scrub-wash capability may be the preferred wash approach.

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- Grade the solar field so that mirror-wash trucks have a smooth flat surface near the mirrors to drive on. Consider grading the solar field to drain water away from mirror-wash access roads so that mirror-wash vehicles can access the field quickly after rainstorms. This concept for access is also good from the emergency response perspective, as well.

- Make sure roads in the solar field are designed for mirror-wash vehicles to have good access to the collector loops. Avoid elevated road edges and slopes that make it difficult for mirror-wash vehicles to access the end of the collectors.

- Mirror-wash vehicles will kick up dust when driving on dirt. This typically limits the speed that trucks can drive through the field when washing collectors.

- Design header piping with mirror-wash access in mind. Make sure piping expansion loops are not placed where mirror-wash vehicles need to have access. Consider running north/south headers inside a loop instead where mirror-wash vehicles would normally want to operate.

- It is important to periodically wash the glass envelope on the receiver. Receiver manufactures put antireflective coatings that can be damaged if the glass is mechanically washed. Spray washing is preferred for cleaning receiver glass to avoid damaging the antireflective coating.

- Collector designs should allow good access to mirrors. The LUZ LS-3 receiver support is a good example of what not to do. The receiver supports block access to drive-by scrub washing of the inner mirrors on the collector.

- It is good to clean all loops in a subfield all in the same night. Clean mirrors will outperform dirty collectors. These sections will need more HTF flow to maintain the same outlet temperature as dirty loops. Operators can then adjust the HTF flow to cleaner field sections. This allows more uniform outlet temperatures from each field section. However, if both clean and dirty mirrors are in the same subfield, either a lower field outlet temperature will be achieved or defocusing of the newly cleaned collectors is required.

- Make sure the back sides of mirrors are cleaned periodically. Dirt on the back side can relocate to the front side of the mirrors.

- Facilities in dusty areas will wait until 20 minutes after the rain has started to position the mirrors up for rain wash. That allows the rain to first clear the dust out of the air; then the rainwater should be clean to wash the mirrors.

- Plants should develop a rapid-wash response plan for times when they experience a high mirror-soiling event.

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5.2.8 Instrumentation and Controls

The collectors have a local controller (LOC) and instrumentation that enable the collectors to track the sun and communicate with the central solar-field supervisory controller (FSC). Solar-field instrumentation and controls need to survive outdoors for 25–30 years. It is important that the appropriate components are selected that allow high reliability of the solar field.

Background

Each collector typically has a local controller to control its operation. The LOC communicates with the central FSC system. In early plants, both of these systems were custom-designed hardware and software, which often led to issues of obsolescence and difficulty in finding spare parts. More recently, programmable logic controllers (PLCs) and other standard hardware products are available for the LOC on parabolic trough collectors. The central FSC software is typically still custom software provided by the solar-field provider, but it tends to run on Windows or UNIX computers that can be more readily tied into the plant's DCS. This allows improved access to solar-field collector information.

Any I&C equipment on the collector exposed to sunlight will experience elevated temperatures well in excess of air temperature. All I&C components should be rated for elevated operating temperatures and also for winter operating conditions. Housings and exposed instruments should be painted white to reduce thermal loads.

A number of plants have experienced issues with lightning, which can affect both communications and power to collectors. It is important to have good grounding systems for collectors to protect I&C and power supplies.

Some plants that use wired communications have experienced communication problems. Fiber-optic communication has been used successfully. It is best if some form of redundancy in communication is used such that no single failure will cause a collector to lose communication with the central FSC.

It is important to purchase quality components for installation on the collector (e.g., inclinometers, shaft encoders, resistance temperature devices, or thermocouples). They need to be designed for outdoor use and be tolerant of high and low temperatures, moisture, ice, snow, and sun. Cabling and connections need to be outdoor rated. Care must be taken to make sure components and cabling are not exposed to concentrated sunlight. It is best to use components that have a proven track record.

Most collectors use open-loop control to position the collectors to track the sun. This means that they rely on a calculated sun position. For this calculation to be accurate, it is very important that the exact location and orientation of the collector is known relative to true north/south, but also, that the exact collector inclination is known. Inclined collectors also have a different algorithm that is often ignored, which then leads to significant errors. Several plants have experienced issues with performance of the solar field because the incorrect coordinate locations were used in the sun-tracking algorithms. In some cases, this resulted in a performance loss greater than 10%. Once these locations were corrected, solar-field performance improved to where it was expected. For large solar fields, different location corrections need to be used for collectors in different areas in the field.

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Best Practices

- All I&C components should be designed for the outdoor conditions that they will be exposed to.

- Potential obsolescence and spare-part availability is a major concern for the solar-field LOCs. Components, especially LOCs, should have industrial-standard rather than custom designs by small single companies. Those components need to be available years after commissioning during the entire plant life. Availability should not depend on single small companies or individuals (programmers).

- The solar-field power and communications should be designed for lightning strikes. The field should have a good grounding system, separating the grounding for I&C from the general grounding. Fiber-optic communication is likely preferred over wired communication due to potential lightning issues.

- Communication should have redundancy, if possible.

- If open-loop sun-calculated position is used, make sure each collector knows where true north is.

- Dedicated screens for the communication system of the solar field are very handy when troubleshooting communication issues in the field.

5.2.9 Drives

Reliability of drives is very important.

Background

Early plants suffered low availability of drives. Most of these drives used motors with gear boxes. Later designs used a dual hydraulic-ram design, which has had good success. Care must be taken to make sure the appropriate hydraulic fluid is used and to avoid hydraulic fluid leaks. It is important that the collectors be able to defocus if HTF flow stops in the collector. This situation can occur if the plant loses power because there is an issue with the grid or if the transmission line is tripped. Typically, the plant will have an uninterruptable power supply (UPS) and a diesel generator to provide power for critical equipment. However, the UPS/diesel generator is usually not sized large enough to run the main HTF pumps. The normal response to a loss of power is to defocus the solar field. Many plants install dedicated UPSs to power the drives to defocus the collectors. Some plants with hydraulic drives use a hydraulic accumulator on the drives that supplies enough reserve to be able to defocus the collectors. At many plants, the UPS for the solar field has been undersized, so only a small percentage of the field can be stowed at a time. The usual approach has been to first defocus the collectors in sections and then move the collectors to stow position a section at a time.

Best Practices

- The solar field should have the ability to emergency defocus if there is a loss of power and HTF flow while the collectors are tracking. Many plants with hydraulic drives have successfully used hydraulic accumulators. Otherwise, many plants have used UPSs for

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backup power to first defocus and then stow the collectors. There is no guarantee that an emergency diesel will start up in time to protect the solar field.

- On hydraulic drive designs, the drive unit has a cylinder switchover point. If this switchover point is set incorrectly, the cylinders press against each other, and this can bend and damage the entire drive pylon. This aspect must be given top priority when commissioning the drives.

- A solar-field installation can take over a year. In a solar field that was constructed in a corrosive aggressive environment, the new cylinders stood still for many months, and rust spots formed on them. The cylinders were then moved during commissioning, and the rust spots damaged the cylinder seals, causing many drives to leak. Therefore, in corrosive environments, it is very important to protect (e.g., grease, cover) the cylinder piston rods during the long standstill phase. During daily operation, the formation of dangerous rust spots is less likely due to the constant oil wetting of the cylinder piston rods.

5.3 Parabolic Trough Solar Field

This section describes the general best practices for designing a parabolic trough solar field.

5.3.1 Solar-Field Layouts

When selecting a site for a parabolic trough solar field, the optimum site will allow the solar field to be laid out in a rectangular footprint.

Background

Typically, the collectors are laid out in rows in a north/south orientation, which typically provides the maximum annual electrical generation. The supply (cold HTF) and return (hot HTF) headers are laid out in an east/west direction. Depending on the size of the plant, there will be one, two, three, four, or even more sets of east/west supply and return headers.

The north/south orientation provides the maximum annual generation in the case that daily solar irradiation is symmetrical for mornings and afternoons. Sites in coastal areas typically have an asymmetric irradiation: morning haze due to water evaporation and clear afternoon sky. In contrast, desert sites typically have clear morning skies and afternoon haze due to atmospheric thermal turbulence, which causes dust to be blown up. Thus, for maximum annual generation, the collector axis should be rotated from the north/south orientation counterclockwise in coastal areas and clockwise in desert areas.

Calculations with real measured DNI at a location in Abu Dhabi showed that an increase in annual electricity generation of 2.8% would be possible by rotating the solar collector axis 68° counterclockwise from the north/south orientation.[24]

[24] "Optimizing Solar Field Layout" by Georg Brakmann and Miroslav Dolejsi of SolEngCo GmbH at the "CSP TODAY South Africa 2015" (http://www.solengco.com/publications/2015-4-OptimizingSolarFieldLayout.pdf)

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Experience has shown that generally the lowest-cost approach and best operational approach is to lay out the solar field in a rectangular pattern. This is not always possible because of the shape of the land parcel available. However, in some cases, sites were selected without a full understanding of the cost impacts of the site.

Best Practices

- Sites should be selected, if possible, to allow a rectangular layout and, where appropriate, allow the field to be a mirror image from north to south and east to west. This should generally minimize capital costs and pumping parasitics. Also, this typically makes it easier to balance flows to different field sections. The Solana plant, for example, has eight subfields (two per set of headers). The regular layout allows good flow control between different field sections.

- It should be checked if the daily solar irradiation is symmetrical for mornings and afternoons. For asymmetric irradiations, the collector axis should be rotated from the north/south orientation for maximum annual output.

Figure 5-2 shows samples of 30-MW, 80-MW, and 250-MW net electric power plants that have one, two, and four east/west headers, respectively. These represent optimized layouts. Plants that have significantly strayed from this approach are more costly and have more difficult control.

These figures are based on specific collector sizes. It is worth noting that the newer generation of larger collector designs such as the Ultimate Trough and the SpaceTube may allow longer collector loops. These allow larger plants to be built with fewer headers. Generally, fewer headers is a cheaper approach. However, the overall hydraulics of the collector loops and headers must be considered. The main concern is the maximum velocity of fluid in the collectors and the maximum operating pressure in the collector loop and the pressure drop in the HTF system.

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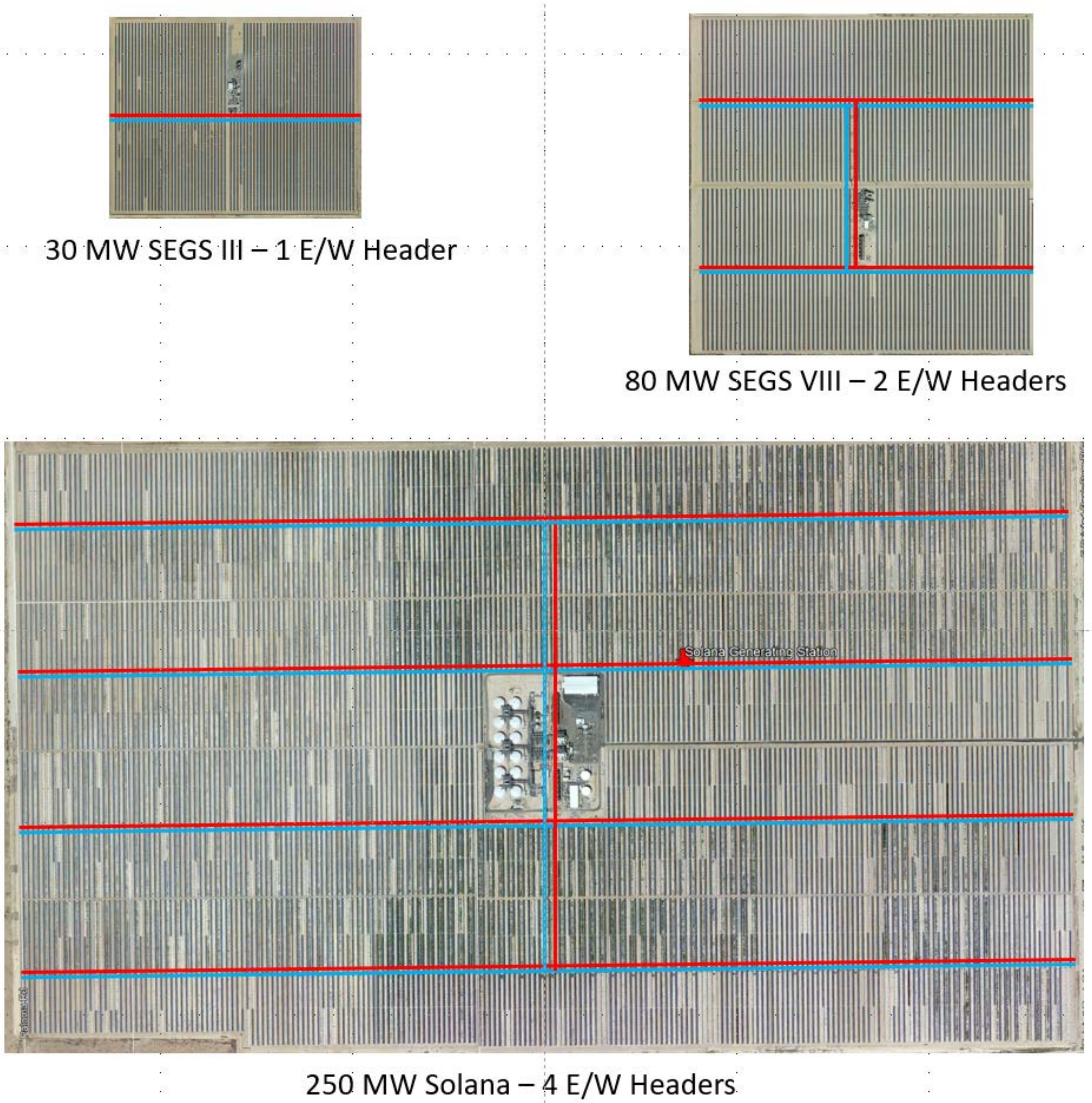

Figure 5-2. Ideal rectangular layouts for solar field with for 1, 2, and 4 headers
Source: Google Earth

5.3.2 Grading and Drainage

When selecting a site, it is important to consider the grading and drainage requirements. These can have an impact on capital costs, O&M cost, and even performance of the plant.

Background

Drainage: It is important to understand how the site fits into the regional drainage scheme. The desired approach is to select a site where onsite water flows can be controlled without offsite water flows crossing the site. Building channels to route offsite flows across or around the plant can be expensive. However, it is rare to find a large site that does not require some controlling of

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flows. Desert areas are known for flash flooding, so it is important to consider potential flooding issues. Locating plants near existing rivers and lakes is likely to be a poor choice.

Slope: The ideal site would be level in the north/south direction and close to level in the east/west direction. Trough collectors can generally be built at an incline of up to about 3% slope in the north/south direction. However, such slopes can lead to a number of issues with collectors, including movement of the collector, tilting of pylons, interference of the collector and the pylons, and changes in relative performance between loops as the sun position changes. On the other hand, if the slope is toward the equator, it will reduce the cosine effect and result in a slightly higher performance. It is generally preferable to be able to install collectors flat with zero slope; but it is likely cheaper to build the collector on a slope rather than grading the site flat. If collectors are to be sloped, it is preferred that all collectors in individual subfields are installed at the same slope. Fields can be terraced to allow for some change in elevation across the plant in the north/south direction. For sloped sites, usually a combination of terracing and sloping of subfields is used. Keeping the slope of sites to well under 1% is desired. Sloped sites can add a significant amount of engineering and civil works to the project, resulting in increased cost. Changes in slope in the east/west direction are less critical; however, it may affect row-to-row shadowing early and late in the day. But some slope in the east/west direction can be beneficial to help with natural drainage of rainwater runoff in the solar field. Note that any changes in slope of collectors across the solar field will mean that the collectors will perform differently from each other at different times of the day and could make maintaining good flow balance in the solar field more difficult.

Solar-Field Drainage: One issue that has been seen at plants that are relatively flat is that water saturates the portions of the solar field and does not drain off. This makes it impossible to drive vehicles in the field without causing ruts in the solar field. One approach to address this is to grade the solar field such that there is a depression in between rows of collectors in the same loop and a slightly elevated area in between loops. This allows water from rainstorms to run off to the depression and allows the elevated sections to dry out quicker. This helps to allow much quicker access to the solar fields after rainstorms, with the elevated areas being where the mirror-wash vehicles access the collectors. One other side benefit is that the depressions where the water gathers also tend to be where vegetation grows. This reduces the area where vegetation must be cleared out or herbicide spraying is needed.

Design for Mirror Cleaning: Although most plants appear to generally be laid out to enable easy access for mirror cleaning, many plants have design issues that impede access to mirrors by mirror-cleaning vehicles. These issues include location of headers and piping, the location of the UPS building in the solar field, drainage ditches, uneven road edges, and in general, a lack of smooth grading in the solar field. Solar fields should be designed to enable rapid access by mirror-cleaning vehicles. There needs to be clearance from headers, loop piping, power and communication cable access manways, and drainage. The plant needs to be designed for the specific type of vehicles that will be used to wash the mirrors. Roads should be designed to allow rapid access.

Mirror-cleaning vehicles are expensive and must be driven slowly around the solar field for safety and to minimize dust. For large plants, it can take a significant amount of time to return to the central plant to refill a wash truck. The time to return to the center of the plant to refill can

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consume a significant amount of cleaning-shift time. Consider adding mirror-cleaning water fill stations around the plant to reduce the amount of drive time for mirror-wash vehicles to fill up with water. A separate water truck can also be used to move water to the mirror-cleaning vehicles around the plant.

Best Practices

- Consider how a site fits into the regional drainage plan. Building channels around and through sites is both expensive and consumes valuable land area. Desert sites need to consider the impact of flash floods.

- The ideal site would allow the solar-field collectors to be installed level (in the north/south direction). This may not be possible or may be expensive to do. Collectors can be installed at slopes of up to 3%. This can have capital cost, O&M cost, and performance implications. Uniform slopes of less than 1% are best.

- Consider how water drains from the solar field after rainstorms. It is important to restore access to the solar field to allow mirror washing to resume as quickly as possible and to allow emergency access to the solar field. One approach to address this is to grade the solar field such that there is a depression in between rows of collectors in the same loop and a slightly elevated area in between loops. This allows water from rainstorms to run off to the depression and allows the elevated sections to dry out quicker.

- Solar fields should be designed to enable rapid access by mirror-cleaning vehicles. Care must be taken for the layout of headers and piping, roads, and drainage to allow mirror-wash vehicles rapid access to 100% of the solar-field collectors. Large plants may want to consider remote fill stations to reduce the amount of time spent driving the cleaning vehicles to refill water tanks.

5.3.3 Collector-Loop Configuration

The collectors are typically laid out in a configuration where the ~500–600 meters of collectors are arranged in a loop. HTF enters the cold side from the supply header at about 292°C, flows through 300 meters of collector, then crosses over to the adjacent row and flows back through 300 meters of collector to the loop outlet, where the HTF exits the loop at about 393°C into the return header.

Best Practice

- Loops should be designed to make sure they have turbulent flow throughout the normal range of operation. Some plants have installed shorter loops and risk operation in non-turbulent flow regimes if they attempt to achieve full temperature at the outlet of the loop.

5.3.4 Loop Valves

There are valves for loop isolation, flow balance, drain and venting, and pressure relief on each collector loop in the solar field. It is important to select the correct valves for each purpose and to make sure the system is designed to function as needed.

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Background

Loop Isolation: Normally, it is common practice to install isolation valves on each collector loop. Loops are often on both the north and south sides of the supply and return headers, so it is possible to use one set of valves to isolate both loops. This would normally be done to save capital cost, but ramifications include the following: both loops need to be isolated and drained if maintenance needs to be done on either one; time and complexity are added for maintenance, and it doubles the amount of collector area that needs to be taken out of service. In one plant where this was tried, it became a major problem.

Typically, gate valves were considered for this application. There have been a couple instances at operating plants where a significant leak or fire occurred at the end of the loop near the isolation valve and the valve could not be accessed to isolate the leak. This situation resulted in extended leaks and fires that have been very public news. One approach used to address this particular concern is to install a quarter-turn ball valve for isolation and attach a cable to allow the valve to be closed from a distance by pulling on the cable.

Loop Pressure Relief: Because it is possible to close both the inlet and outlet isolation valves on the collector loop, it is necessary to have over-pressure relief on the loop. Early plants installed pressure-relief valves that opened to the ground or a French drain. Later plants installed the pressure-relief valves on the hot side of the loop, with the pressure relief around the isolation valve to the hot header. More recently, several plants have used conventional check valves in place of pressure-relief valves. This was found to work well and reduced valve maintenance.

Loop Drain and Venting Valves: Although these are not particularly interesting, it should be mentioned that these valves often have leaks and should therefore be closed with blind flanges or caps. Vents should be higher than drains, which is a particular concern with sloping fields.

Loop Flow-Balance Valves: Many plants have indicated difficulty achieving a good flow balance between loops in the solar field. It is necessary to install flow-balancing globe valves in every loop to account for the different header pressure drop seen by each loop. It is important that good-quality globe valves are used with an appropriate linear flow coefficient (Cv) appropriate for each location. The goal is to create uniform flow through each loop. In an ideal world, this would also mean a uniform temperature out of each loop as well, but this will not be the case because each collector may perform slightly differently and have different cleanliness levels. A detailed hydraulic model must be used to accurately determine the proper Cv required for each globe valve. This has been shown to work very well at several plants.

One plant has been able to achieve very good flow balance in field sections with 100 loops using quality globe values with appropriate Cv values and using a hydraulic model to determine the proper valve settings. This plant also developed a clever approach for using the collector temperature sensors to measure the flow in individual loops, which allowed them to verify the flow balance in the field.

Many plants notice that the flow balance can change between summer and winter. Many believe this is due to changing mass flows, but it is more likely due to changing temperature profiles in the field. In any case, the flow balance may not remain constant from summer to winter. It is important that flow balance is checked periodically. Flows in external loops may be lower with

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lower HTF temperatures. Flows in these loops should be used for monitoring the minimum flows to the fields.

Actuated Flow-Control Valves: Many plants installed actuated globe valves at the inlet to the loops. The goal was to allow real-time flow control on loops to maintain outlet temperatures. For the most part, these valves do not appear to be used for this purpose. We recommend using good-quality manual globe valves for flow balancing and not attempting to do temperature control on individual loops.

Best Practices

- We recommend that each loop have its own set of isolation valves.
- Use a quarter-turn ball valve for isolation and attach a cable to allow the valve to be closed from a distance by pulling on the cable.
- Use check valves around the block valve at the hot side of the loop to the hot header to provide over-pressure relief on the collector loop.
- Develop a detailed hydraulic model of the solar field with as-built piping. Use this model to determine the valve-trim flow coefficients (Cv values) for each location.
- Monitor the flows in external loops during wintertime. In many cases, the models are only valid for nominal operation; but when the flow decreases in winter, especially at lower HTF temperatures, the external loops may not receive enough flow.
- Select good-quality manual globe valves with linear Cv trim adjustment. Use valves with demonstrated performance in HTF trough plants. We do not think it makes sense to put actuators on the globe valves on each loop because these seldom get used and become a significant maintenance burden.

5.3.5 Loop Temperature Control

It is important to manage the outlet temperature of each loop of collectors to make sure that the HTF is not overheated under high solar conditions or reduced HTF flow conditions.

Background

There are times when more solar energy is available than can be transferred to the HTF without overheating the HTF. This may occur during peak solar conditions or in other conditions when (1) flow may be limited due to thermal storage being full or (2) when operating during a partially cloudy day when some collectors are in full sun and others are partially shaded. During all these cases, it is important that some of the collectors in the loop are defocused (also referred to as blurring) to protect the HTF from overheating at the outlet of the collector loop (exceeding ~395°C). Usually, this is done by partially or fully defocusing one or more of the collectors in the loop.

One approach has been to partially defocus all the collectors in the loop by the same amount. This has been shown to work well for loop outlet temperature control at a number of plants.

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There has been some concern that partial defocusing of collectors can result in higher peak fluxes on receiver tubes even though the average flux is decreased. Figure 5-3 shows the flux around a receiver tube that is in focus and the flux on a receiver tube that is 0.5 degree defocused. In this example, even though the total flux on the receiver decreases by 7% on the defocused receiver, the peak flux increases by about 20%. This could cause localized overheating and breakdown of the HTF and could even potentially cause damage to the receivers, especially during low-flow conditions. There is also some concern that during the winter when there are high incidence angles, this can cause high fluxes on the inside of the receiver and cause damage to the bellows or the glass-to-metal seals. We understand that the designs of newer receivers address this potential problem.

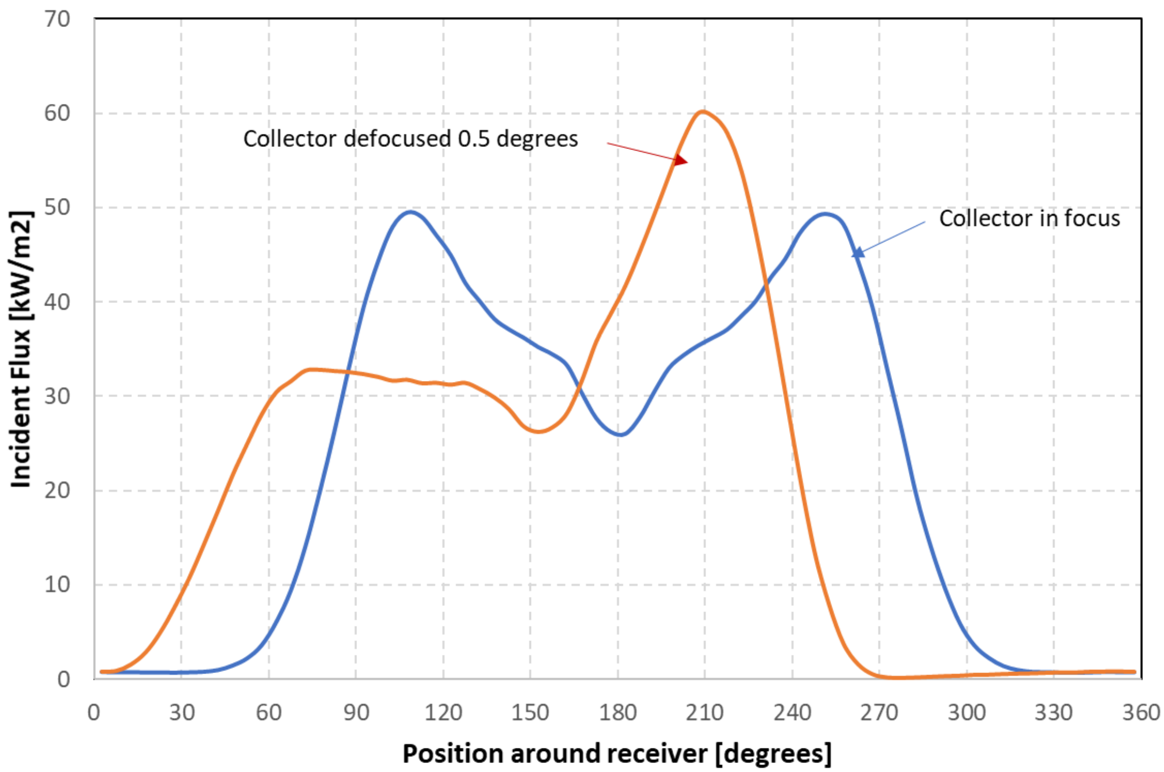

Figure 5-3. Flux profile around PTC receiver (8.2-m collector aperture, 89-mm outer-diameter receiver)
Source: Solar Dynamics

Typically, each collector has a temperature sensor located at the center of the collector that monitors the HTF temperature and is used to determine if the collector should be defocused to prevent overheating of the HTF. Many plants also add a temperature sensor at the outlet of the loop to monitor the temperature coming out of the last collector. This provides the best way to monitor the outlet temperature of the loop. Other plants without this temperature sensor at the loop outlet must estimate the loop outlet temperature based on the temperature readings at the center of the last collectors. This can be approximate depending on whether the collectors are all tracking or if some have been partially or fully defocused. Estimating the outlet temperature can be even more problematic during partially cloudy conditions, especially if HTF flows are reduced because the storage is full. Without the temperature sensor at the outlet of the loop, it is more likely that the HTF could be overheated at the loop outlet.

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It has been suggested that isolating a portion of the solar field may be a better approach when there is excess energy due to the thermal storage being full. This can have its own issues because this portion of the field will cool down and then need to be carefully reopened when the field is put back in service to avoid thermally shocking the collectors and mixing cold HTF from the collectors back to the hot HTF.

There is some question as to whether a resistance temperature device (RTD) or a thermocouple should be used for the collector and loop outlet temperature sensors. Both appear to have been used successfully. RTDs tend to be the temperature sensor of preference for general process applications, so we tend to default to the RTD inserted in a thermowell as the sensor of choice.

Best Practices

- Collector loop temperature control that is based on partial tracking of all solar-collector assemblies in the loops seems to be good in clear-sky conditions. It is not clear if this approach works well during intermittent (partially cloudy) solar conditions and during high solar but low HTF flow conditions (when TES is full).

- Adding a temperature sensor at the outlet of the loop adds cost but helps reduce the likelihood that the HTF maximum temperature is exceeded at the loop outlet.

- It is worth noting that it is important to maintain good flow balance to maximize thermal output from loops.

5.3.6 Solar-Field HTF Flow Control

Controlling the HTF outlet temperature of the solar field is very important to achieve peak performance from the plant and to not overheat the HTF.

Background

Although several newer plants have automated HTF flow controls, it appears that most plants rely on an operator to manually control the HTF flow in the solar field. Automated HTF control should allow better overall performance from the solar field, will help protect collector receivers, and minimize HTF degradation. Manual flow control offers suboptimal performance—by either causing unnecessary overheating and defocusing of collectors or not achieving peak solar-field outlet temperatures. During daily start-up, the tendency may be to not increase flow quickly enough to avoid overheating in the solar field. The most complicated control situation may be what to do on partially cloudy days, where it may be difficult to predict whether skies are clearing or becoming more overcast. Automation of HTF flow control is complicated, especially for larger complex plants with multiple TES and SGS systems. It does not appear that there is a clear methodology for how to automate HTF flow control.

The trough community can learn from the experience of the molten-salt tower community. In the case of molten-salt towers, much care is taken to make sure the receiver is always protected from a potential overflux event. A molten-salt tower plant's primary control is based on assumed clear-sky radiation. The flow is then fine-tuned based on other parameters. Trough technology can use a similar approach. The initial flow signal can be based on actual solar resource measurements on clear days. However, on partially cloudy days, the flow can be fine-tuned based on the temperature measurements in the collectors and how they trend over time. This

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means that the solar-field HTF outlet temperatures may be lower on partially cloudy days, but more energy overall will be collected. The plant process design needs to account for this mode of operation. The plant SGS and TES need to be able to deal with derated HTF supply temperatures and the temperature gradients that they will see. If the power plant is online, the return HTF temperature may be lower than design; so, some HTF can be bypassed around the SGS and TES heat exchangers to maintain the design inlet temperature to the solar field. Reduced solar-field outlet temperatures will result in a derating of the TES capacity and reduced hot-tank temperatures. The TES design will need to accommodate this type of operation.

Minimum Flow: The parabolic trough receivers require turbulent flow when collectors are in focus tracking the sun. This assures that good heat transfer will be present, minimizing temperature gradients around the absorber tubes. When collectors are not tracking, the minimum flow is assumed to be at least 20% to maintain a reasonable hydraulic balance in the solar field. However, it is possible that at low HTF temperatures, a higher minimum flow may be required to maintain a reasonable flow distribution to distant portions of the solar field.

Solar-Field Flow during Daily Start-Up: There are two general approaches that can be used during start-up of the solar field. One school of thought is to start up the solar field with minimum flow so that a rapid increase in HTF temperature can be achieved. The second approach is to maintain a relatively high flow rate, which results in a more rapid equalization of HTF temperature throughout the plant but results in a more gradual temperature increase. The second approach appears to allow for a better, more-controlled start-up, especially in large plants.

Continuous HTF Flow at Night: Early plants found that maintaining continuous flow of HTF 24 hours per day helped maintain more uniform temperature throughout the HTF system and minimized equipment exposure to rapid temperature gradients that occurred when pumps are first switched on. When pumps were switched off at night and then restarted in the morning, there was significant receiver breakage due to bowing of tubes because of rapid temperature gradients. Clearly, running pumps 24 hours per day increases plant parasitic electric consumption. Many plants now include special nighttime circulation pumps that allow the solar field to be circulated at lower velocities and that separate the solar field from the HTF in the power-block area. This type of system does require that the two sections of the plant are brought back into temperature equilibrium at the start of the day.

Subfield Flow Control: It is important that each subfield have its own flow-control valve to allow HTF flows to be balanced between different subfields. These valves should have automatic positioners. This is helpful to balance flows depending on subfield cleanliness and collector availabilities.

Best Practices

- The HTF flow through the solar field should be automated to maximize efficiency and protection of equipment and HTF.
- We recommend high minimum HTF flows when the collectors are tracking. HTF flow should always be well into the turbulent region. The DCS should have low-level flow alarms that will defocus the solar field.

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- We recommend maintaining high flows during daily start-up of the solar field to maintain gradual temperature transients.

- We recommend 24-hour circulation to minimize temperature gradients in the HTF system.

5.3.7 Collector Interconnection

The interconnection piping between the headers and receivers on the collectors is one of the most challenging areas for parabolic trough collector technology. Flex hoses, ball joints, and rotary joints have all been tried with varying degrees of success.

Background

The collector interconnection piping connects the collector receiver tubes to the HTF supply and return piping and the receivers of two adjoining collectors in the collector loop. The interconnection piping must account for the rotation of the collector and the thermal expansion of the receiver tube as it heats up from ambient to operating temperatures. The SEGS plants originally used flexible hoses (without rotary joints) to connect the receivers on the collectors to the header piping and in between collectors. Initially, some of the early plants had quality issues with flex hoses.

KJC Operating Company developed ball-joint assemblies as an alternative solution to be used in place of flexible hoses. The ball-joint assemblies had a much lower pressure drop than flex hoses. The early SEGS plants had shorter collectors (50 m long) and had as many as 16 collectors in a loop. Thus, the increased pressure drop in flex hoses had a much larger impact than they might today, with most current plants having only four collectors in a loop. Ball-joint assemblies have had some problems, as well, with some brands of ball joints working better than others. The ball joints use graphite packing material. The daily temperature cycling of the ball joints appears to cause leaks over time. Operators at one plant believe they are losing 2% of their HTF per year primarily due to ball-joint leaks. This requires the ball joints to be repacked with additional graphite material, which is a labor-intensive effort and requires the loop to be depressurized to repack the ball joint. Care must be taken to make sure the ball joints are not overpacked, which can cause the ball joints to bind up. One participant commented that packing a ball joint is more of an art than science—it is difficult to get it right.

Several different design configurations of ball-joint assemblies have been used. It is not yet clear if one design works better than others. Additionally, if ball joints get out of position, they can reach the end of their travel. There is some indication that this may be the cause of leaks or binding. Keeping ball joints in the proper position may be key to long-term good performance. Currently, it does not appear that ball joints represent a good long-term, low-maintenance solution.

Rotary joints with flex hoses or bellows joints have been used as an alternative solution. There has been some very good experience with this solution. Proper design and installation become critical to good long-term performance. It is critical to install the rotary joints without piping loads being transferred to the rotary joint; flex hoses have been used successfully to do this. If done well, the rotary joint with flex hoses appears to be an excellent solution.

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The SEGS VIII and IX plants are in their 30th and 29th year of operation, respectively. They still have many of their original flex hoses installed. In discussions with the plant operator, we understand that they did not have quality issues with the original flex hoses and believe they remain a good solution. However, they agreed that the original flex-hose design was not an ideal solution, and they thought that the flex hose with a rotary joint could be a preferred solution.

There are new flex-hose designs that are being developed for use with molten salt as the HTF in trough plants. These hoses could also be good solutions for use in oil HTF plants. These designs provide better support for the flex hose and only allow bending in one direction, which appears to address the main failure modes of flex hoses. This solution has a higher CAPEX, but it may pay for itself in reduced OPEX costs.

Best Practices

- We do not recommend that traditional ball-joint assembly designs be considered. If ball joints are to be used, special care on the design and installation is recommended.
- The best solution currently appears to be rotary joints with flex hoses or bellows. A high-quality ball joint in place of the rotary joint might also be a reasonable solution.
- Some of the newer flex-hose designs without rotary joints should also be considered.

5.4 Heat-Transfer Fluid System

This section specifically addresses the issues and best practices associated with HTF pumps; HTF valves; HTF piping; ullage system; HTF instrumentation and automation; and the auxiliary heater. These topics were specifically mentioned by participants of the project regarding the HTF system.

5.4.1 HTF Pumps

HTF pump reliability has been noted by many participants of this project as a considerable issue relative to plant availability and/or maintenance costs. In addition, failures of the seals may present safety and/or environmental concerns. On the other hand, some participants noted that the HTF pumps were not a major issue; most pump issues were related to the reliability of the pump seals.

Background

In general, participants noted that they have experienced improved HTF pump reliability over time. In general, pump designs (including seals and use of proper piping plans) have improved; in some cases, alternative designs of the seal were used and/or auxiliary systems were modified with the assistance of the pump manufacturer to improve reliability.

The piping plan is a configuration of accessories, instruments, controls, and/or fluids designed to manage or control the environment around the seal. The need to control the environment around the mechanical seal arises from the need to maintain the fluid in a state where it is suitable to lubricate mechanical seal faces, which is a paramount objective. Other reasons for using piping plans include safety, environmental protection, and monitoring the seal’s environment through

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instrumentation. Figure 5-4 is a basic drawing of a piping plan, Plan 53B, often considered for CSP.

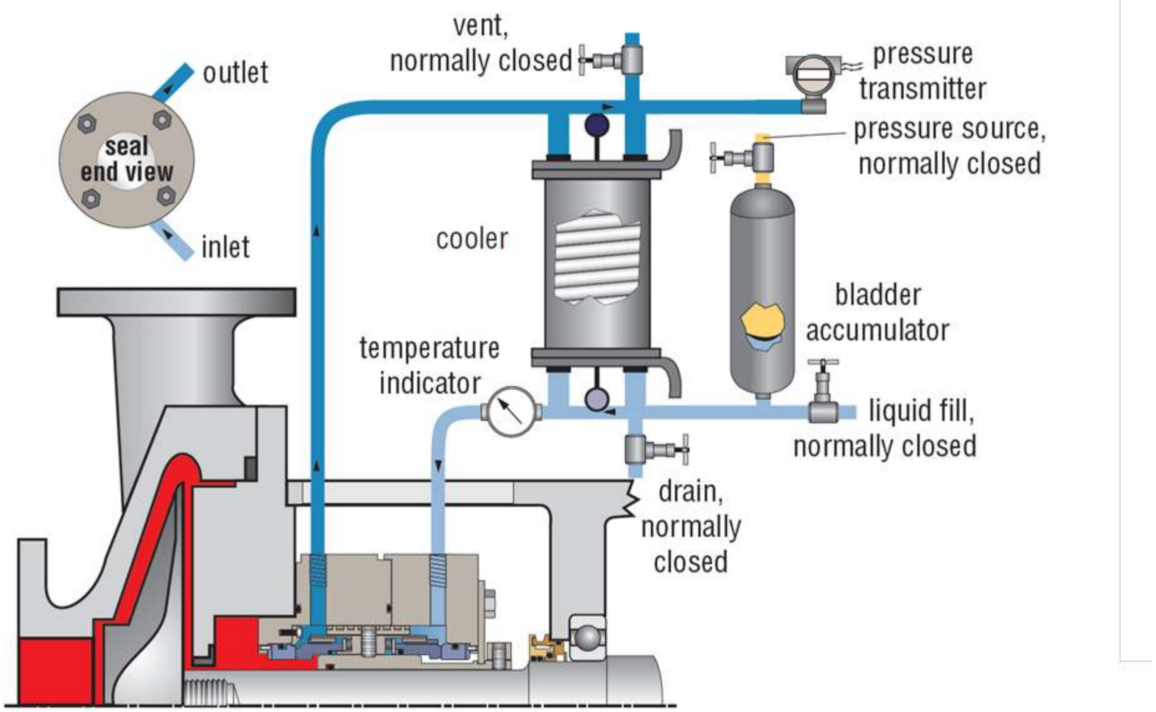

Figure 5-4. Common piping plan, 53B
Source: Flowserve

Most of the failures discussed with participants were not specific in root cause. In one case, the participant believed that high water content in the HTF (from leaking heat exchangers) may have contributed to seal failures. As water was removed from the HTF, seal failures in the HTF pumps decreased. Other participants have had unreliable components (pumps) for the piping plans auxiliary system equipment even though the design of the system was appropriate. Some participants have kept in place the original designs and have had success with the reliability of their pumping systems. Cavitation was also brought up as a possible contributor to seal failures.

Pipe stress and proper alignment is also believed to be a concern of seal reliability. In one case, bellows were used in the suction and discharge portions of the pump piping, and no failures had occurred on the pump seals. It was also noted that most of these bellows had begun to leak and were in progress of being replaced.

Incorrect installation of pump foundations and mountings has also led to excessive vibration and pump failures.

Lack of variable-frequency drives (VFDs) for the HTF pumps was noted by one participant as being responsible for damaging flow-control valves. This same participant noted that each pump start caused excess movement of the HTF piping in the pipe racks.

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Best Practices

- With proper design, HTF pumps can be very reliable. However, the potential cost impact of not having adequate HTF pump flow capacity is significant. Therefore, we believe it is a best practice to have installed operational capacity (n+1). All HTF pumps should have VFD capability.

- Plants that have n+1 pump capacity with VFDs may choose to run all pumps during peak load periods. This makes it easy if one pump goes out of service to pick up load on the remaining pumps. This is less complex than trying to bring a pump in warm-standby online. Experience has shown that operating all pumps at partial capacity can actually lower pump parasitic load, but this will depend on the specific system design.

- The EPC and pump supplier should both understand all the process conditions that the pumps will be exposed to for the design of a reliable pump system. In general, this information would consist of: HTF flows; HTF temperatures; HTF temperature gradients (transients and trips); ambient conditions, HTF pressures; HTF fluid quality (water content, low-boiler and high-boiler level). The specification to the pump manufacturer must include all process and operating conditions and possibilities that result from the requirements of the OTS.

- The piping plan auxiliary system equipment and components need to be designed together along with the pump design. Issues have arisen where these are built by separate entities. One entity should be responsible for design and specification of the entire package.

- For the HTF pumps and associated equipment, the EPC should have a QC representative auditing the factories to ensure that equipment is being built to the agreed upon specifications. The owner through its OE should assure that this is done.

- Relieving pipe stress during installation, proper foundations and mounting, and proper pump alignment are crucial for longevity of seals for pumps. Use industry-standard procedures and ensure pump-manufacturer requirements are being followed during the installation. It is also important to have adequate QA/QC during this installation process to ensure that all manufacturer specifications and industry standards are met.

- Using bellows on the pump piping has worked at some plants to reduce/eliminate seal failures. However, one plant noted that the bellows had incurred a small amount of leakage, and the plans to replace them were in progress. It was anticipated to be a significant effort to make these replacements.

- Pressurized dual seals should be used instead of single seals because single seals introduce a certain amount of safety and environmental risk if the hot fluid is leaked to atmosphere. Dual seals have also been shown to be more reliable than single seals due to vapor lock with single-seal auxiliary equipment and are impacted more from contaminants within the HTF. Critical elements for considering pressurized dual seals are summarized below:

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- Specifications of the pump seal and its components (inner seal, outer seal, bellows) should meet appropriate American Petroleum Institute (API) Standard 682.
- Face-to-face orientation of the pressurized seals has been shown to be the most reliable.
- The inner seal should remain closed under reverse pressurization.
- The outer seal should be rated for the maximum seal chamber pressure and the maximum designed barrier chamber pressure.
- All seal faces should be made of silicon carbide or enhanced by applying a silicon carbide coating.
- Process-wetted secondary gaskets shall be made of flexible graphite and/or metal.
- The seal shall include features to support the collection of barrier fluid leaked to atmosphere.

- Variable-frequency drives should be used for the HTF pump to reduce duty and stress of the solar-field control valves. It would likely eliminate/reduce extreme movement of piping during pump starts when not using a VFD.
- The piping plan and auxiliary equipment is critical to the reliability and longevity of the seal. Critical elements for consideration of the piping plan and auxiliary equipment include:
  - Barrier fluid systems should be designed to maintain barrier fluid at temperatures appropriate for: maintaining a viscosity in the desired range for silicon carbide seal faces; minimizing the thermal stress and oxidation of the barrier fluid; and minimizing the pressure variations.
  - Barrier fluid should be a fresh, clean fluid. Dirty or used HTF can damage seal faces.
  - If acceptable to the process, poly-alpha-olefin-based barrier fluid may be preferred over an HTF barrier fluid. However, poly-alpha-olefin fluid may flash to vapor under some pressure and temperature conditions, so there should be concern with the system temperature and pressure.
  - Barrier fluid systems should be equipped with a pressure transmitter rather than switches.
  - Accumulators should not be undersized and should be made of material chemically resistant to all HTF or alternative barrier fluid.

5.4.2 HTF Valves

HTF valves can be quite challenging to the operations of parabolic trough facilities. Poor valve selection could likely lead to safety, environmental, availability, and/or performance impacts depending on the application. This section addresses the larger bulk-system and power-block

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valving and not the valving associated with individual loops. Those topics are discussed in the section on the solar field.

Background

One problem identified by several participants was external valve leakage associated with the stem sealing. This can be or could lead to safety and/or environmental concerns if not properly addressed. Reliable valve designs and quality valves do exist for these applications, so proper and proven valve selection is important.

Other participants consider a serious concern to be that internal leakage occurs in isolation valves. Often, delays in repair work have occurred due to the inadequacy of isolation valves or delays in getting them to isolate. In some instances, equipment was left out of service or not repaired for years because valves could not be used to isolate the equipment and safely perform the necessary work.

Poor-quality valves have been noted as a cause of this issue; but temperature and pressure differentials have also been noted as causes for lack of isolation and/or binding. As well, piping being forced into position to align with the valves during construction has also been noted as a source of binding.

Throttling applications are another challenge to design in an HTF application. Typically, globe-style valves are used; however, the HTF is prone to cavitate in these types of valves if the trim is not designed properly. Impurities and carbon deposits due to the thermal oil chemistry and breakdown can also add to the challenge of this application and should be considered. In large flow situations, some participants have used butterfly valves; but these have rangeability challenges and make flow control more erratic and may lead to unexpected transients.

Not related to valve performance but to valves, in general, is where they are located. Often, valves are not easily accessible for O&M purposes. This may cause safety concerns and possibly lead to availability impacts or unexpected costs to perform maintenance. In several cases, it was noted that permanent scaffolding was erected to access a valve. The initial plant design did not consider this aspect.

Best Practices

- In general, HTF valves should be of high quality and properly specified for cyclic conditions to ensure reliability and personnel safety due to the temperature extremes and the hazardous nature of HTF. This is not only critical during operations, but also essential for maintenance tasks that require evacuation and isolation of the HTF system.

- For external leakage, a bellows-sealed bonnet valve with safety stuffing box should be considered. A shroud-less bellows seal design is also preferred. Maintenance of the bellows subassembly and risks associated with thermal oil cycle issues are minimal with this design. In addition, graphite-made packing is recommended as the backup to the bellows.

- Ball and butterfly valves are common solutions for isolation (on/off) applications, although gate valves are also used. Ball-style valves are sometimes specified for small-

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size items whereas the butterfly configuration is selected for larger sizes. Both valve styles can offer good seat tightness. In general, the metal seat is critical for high-temperature ball-valve applications. Customers often consider price differences when comparing ball, butterfly, and gate-style valves for a given application.

- HTF valve specifications should consider actual process temperature and pressure differences during isolation to ensure reliable isolation and avoid binding.
- Due diligence should be used for final selection of valves. Experience and track record in CSP-relative applications or similar technology should be sought.
- Valves should be installed with limited pipe stress to avoid potential binding.
- Throttling applications should be specified with globe-style valves using both conventional or anti-cavitation trim depending on the application. The exception comes from applications with very large flow rates, where butterfly valves are sometimes requested because of cost savings. However, butterfly valves present rangeability challenges for throttling large flow rates; so, the use of butterfly-globe valve split-range sets are specified in some cases (to theoretically save costs vs. control globe-style valves), which may lead to increased complexity in the transients of control, costs of piping, and instrumentation. With this split-range configuration, challenges with cavitation and/or control transients have been encountered. In this scenario, control ball valves may be used as an intermediate/balanced solution.
- O&M-experienced personnel should be involved with the plant-layout design to ensure that access to valves and equipment is adequate.
- Safety relief valves on the HTF system should be routed through a scrubbing mechanism (e.g., the ullage system carbon canisters) and placed such that they will not expose employees to a potential release.

5.4.3 HTF Piping

HTF piping-related concerns have contributed to notable impacts and challenges among participants of this project. To varying degrees, this has depended on the participant and design of the facility. The HTF piping-related topics relate to piping support design; piping design and specifications; piping requirements for equipment evacuation; regulatory valves; insulation; and heat trace.

Background

One concern voiced by several participants was that the design of the pipe supports was inadequate for the movement of the HTF piping. However, it should also be noted that many participants mentioned that their pipe supports worked without issues. Most of the issues were noted to be related to the solar-field header piping, but some noted issues in the power block, as well.

Often, the piping configuration is quite complex between the solar-field headers and the inlet or outlet of a loop. The header typically moves one way, whereas the loop piping grows

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perpendicular to the header. In one facility, every fourth inlet/outlet was modified due to interference issues not considered in the design. One facility used ball joints on the vertical header riser to the collector loops to account for the relative growth in the header. Another facility used a flexible-hose section to account for the complex movement along with a much simpler piping configuration without expansion loops in this section. This was reported to be working very well.

A significant concern reported and solved by one that the O&M teams was that the piping configuration was generally not designed to support efficient HTF evacuation of equipment. Drains and vents to expedite this process were sometimes not considered in the design.

Due to concerns about leaking HTF, welded connections are often preferred over flanges. However, many plants have had success with flanged connections, and these typically offer an advantage for maintenance activities and efficiency during that process.

Insulation and heat trace were often mentioned together as a source of freezing instruments/transmitters. This can and will cause impacts to the start-up times of facilities until corrected. At one facility, the ullage system was tented and heated so that it would not freeze in the winter months until the heat-trace system could be modified and installed using the original design. More in-depth discussion regarding heat trace and insulation is in the Molten Salt section because that is a more vital concern with the much higher freezing temperatures.

Using mineral-wool insulation around potential HTF system leak points was noted as a potential fire hazard.

Best Practices

- A good HTF pipe stress study is required for the pipe configuration and support design, considering all operating temperature ranges. It should consider all the HTF piping including power block, solar-field headers, and header-to-loop piping. In some cases, the sizes of the supports were determined to be doubled in size after the study was complete. As mentioned earlier, many plants reported that they did not have issues with the piping and supports.

- An alternate approach considered for the complex section of pipe between the solar-field header and loop inlet/outlet may be a flexible hose combined with a rather simple piping configuration. This has worked well in at least two facilities. The flexible hose moves very little in this application compared to the use of one for the collector interconnection. In the latter, the flexible hose is exposed to much more twisting and rotation—and thus, potential weakening.

- The HTF piping configuration should be reviewed by personnel familiar with, and having expertise in, O&M to check that piping is in place to ensure that equipment can be drained and readied for maintenance in an efficient and safe manner. Also, the O&M subject-matter experts should review drain and vent points for the entire HTF system to ensure that supporting O&M tasks are designed for within the piping design.

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- Proper insulation and heat-trace cabling are critical. Instrument legs (e.g., HTF and water) have become frozen due to improper heat trace or technology to keep from freezing. Production losses are likely without proper freeze protection. This is generally not a design issue, but more about finishing the project. Better QC coordination with supervision and construction representing the owner's interest is important.

- Non-porous thermal insulation should be considered around areas of potential leak points (e.g., flanges, valves, instruments). Cal-Sil is one product that would work, unlike mineral wool. Note that Cal-Sil is much more expensive than the more commonly used mineral wool.

- Installation of HTF sampling ports should be included in the original design.

5.4.4 Ullage System

Ullage systems are installed at parabolic trough plants to remove the byproducts associated with the degradation/breakdown of the HTF (diphenyl oxide and biphenyl). Removal of the byproducts is important to maintain pressure levels in the HTF system and to "clean" the HTF to avoid increases in the rate of degradation and generation of hydrogen.

Background

As the operating temperature of the HTF increases, the breakdown of the fluid accelerates and so does the generation of byproducts. As this occurs, it becomes necessary to remove these byproducts, which generally consist of low and high boilers.

The low boilers (light ends) primarily consist of volatile organic compounds (VOCs), with the most predominant component being benzene. As these constituents increase in the HTF system gas/nitrogen space (expansion vessel), so does the pressure of the system. As such, these low boilers are required to be vented from the system due to pressure constraints. The most common way in plants today is to release these low boilers along with the other expansion-gas constituents (primarily nitrogen) through a carbon bed. The carbon then becomes hazardous material due to the absorption of benzene and will require removal, disposal, and changeout periodically due to becoming saturated and/or no longer being able to control the VOCs to a required level. (A permit usually dictates the emission limit from the carbon bed.) Water is also typically removed from the HTF system through this venting system.

The high boilers (heavy ends) remain in solution with the fluid until they are removed, typically in a distillation/flashing-like process that separates the heavy boilers from the HTF. A portion of good HTF is generally removed during this process, so make-up is required to replace the heavy boilers that are removed and the associated good HTF removed during the process (~50% of the weight of high boilers).

Another breakdown product of the HTF—hydrogen—is also very concerning. Hydrogen is released during the breakdown of the HTF, generally with the heavy-boiler breakdown. Recent[25] studies show that hydrogen formation in the HTF occurs as a function of temperature and the

[25] Based on feedback from several project participants

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level of high boilers and impurities. As these parameters increase, so does the generation of hydrogen. The impact of hydrogen is discussed elsewhere in the report (see Sec. 5.2.5); but, in general, the hydrogen permeates into the receiver annulus (vacuum space) and eventually saturates the getter and then creates a very good thermal conductor in the vacuum (insulated) space. This causes significant increase in receiver heat losses, which significantly reduces electricity production.

In general, two different strategies are used for venting the low boilers. One method keeps a constant pressure on the expansion system, which will increase nitrogen usage and likely the volume of hazardous waste depending on how well the HTF is condensed out of the ullage gas stream. The other method minimizes the use of venting, and thus, nitrogen usage and likely hazardous waste. This method results in a fluctuating pressure of the expansion system. Regarding the hydrogen issue, studies have recently shown that venting more often will remove hydrogen, and it may be a possible method to keep hydrogen levels low enough not to impact the receivers—and at a minimum, it may increase their longevity without a hydrogen impact. Through our discussions with participants, we do not believe that plants have yet fully experimented and performed thorough tests on this matter, although some limited testing has occurred.

As mentioned earlier, high boilers are typically removed through a distillation/flashing-type process. Some participants were not sure of the efficiency and usage of this part of the ullage system, and some plants did not appear to have this portion of the system installed. One plant had often tried to use this system, but it was not designed appropriately to accomplish the task. This participant is currently performing an engineering re-design/cost study in anticipation of modifying the system soon. This system is also important in relation to hydrogen impact because studies have shown that as the high-boiler content increases, so does hydrogen generation.

On a final note, NREL is working with Nevada Solar One on installing a prototype hydrogen removal system for the expansion vessels. Conceptually, this unit would draw the gas stream out of the expansion vessel through a membrane system, where the hydrogen would be separated. The gas would then be pumped back into the system. It is synonymous with a venting system without the waste of nitrogen and hazardous material; however, low boilers will not be removed from this system.

Best Practices

- The high/low boiler and hydrogen treatment approaches should be part of the OTS; thus, this should guarantee to the owner that the EPC will provide adequate design and the necessary equipment for treating the degradation of HTF for the life of the project. The design should consider maintaining hydrogen levels in the HTF system such that: (1) it will not cause an impact due to hydrogen permeation into the receiver annulus for the life of the project, and (2) no replacements of receivers should occur due to hydrogen permeation. This should be based on the anticipated process conditions of the project.

- Breakdown of HTF is very temperature-dependent. Plants should consider designs to operate at lower HTF temperature. Even 5°C lower will make a significant difference. Optimization should be performed to establish the design conditions.

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- A device should be considered to remove hydrogen from the expansion system and that works in concert with the ullage system. No known commercial equipment currently exists; however, NREL is currently testing a prototype system at Nevada Solar One.

- The owner should be made aware—initially by the EPC and later by the O&M team—of the amount of high-boiler removal and make-up of new HTF each year required for a sustainable level of hydrogen generation that will not impact the receivers for the lifetime of the project.

- The owner should be made aware—initially by the EPC and later by the O&M team—of the amount of nitrogen anticipated to be used each year that addresses as best economically the venting concerns for low boilers and sustainable hydrogen levels.

- Special carbon canisters for capturing low boilers should be placed in a vertical orientation with a distribution header at the inlet. Horizontal installations have witnessed channeling. Improper filling of the carbon cannisters has also been noted as an issue.

- A thermal oxidizer should be considered in lieu of carbon canisters. One participant has installed an oxidizer system that resulted in extremely low continuous emissions (almost zero) and has decreased hazardous carbon waste generation, handling, and disposal with the venting system to almost zero.

- The ullage system should also be designed to have the capability to remove water. Water can lead to quicker breakdown of HTF and operational difficulties due to increased pressure/pressure spikes.

5.4.5 HTF Instrumentation and Automation

HTF-related instrumentation for CSP plants is like other proven power-generation technologies, and it generally was stated as being reliable. HTF flow meters were the one noted exception, where some participants claimed reliability and accuracy and others claimed the opposite. HTF instrumentation reliability in some cases was also impacted by freezing due to inadequate heat tracing.

Background

Reliability, consistency, and accuracy are generally considered important with the HTF flow meters for plant operations and for implementing automatic HTF operational scenarios. However, lack of reliability with flow meters has led to other flow-estimating strategies.

Levels of automation were discussed by many participants, and overall, it seems there are different levels of automation used at the different plants, with varying degrees of success and usage. An estimate of HTF flow is essential for automating flow control to the field. Intuitively, a flow meter would be used, but reliability and consistency of HTF flow measurement has been a problem. Other approaches for measuring flow have been used including pump amps, VFD speed, and system pressure drops. These alternate strategies may be more complicated logically for some flow streams (e.g., the division between TES and SGS systems). Estimation of flow streams and proven logic schemes are critical for implementing automatic HTF flow control that optimizes output while protecting equipment/systems.

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Two plants were pleased with some newer schemes developed and implemented for automatic flow control. These plants were ones without molten-salt storage, which, when present, considerably complicates the automatic scheme.

Freezing instruments/transmitters can and will cause impacts to the start-up times of facilities until corrected. Typically, inadequate heat trace and/or poor insulation allows instruments to freeze. This topic is discussed further for HTF systems in the Piping section.

Best Practices

- Due to the potential of the HTF flowmeter to malfunction and the many problems reported by the plant owners, flow meters with a solid track record in CSP plants or similar application should be preferred. New unproven designs should be considered with caution.

- Proper HTF flow control for the solar field and power block may allow for less personnel during the operations of the plant. Correctly implemented, automatic flow control will stabilize and optimize generation, reduce parasitic loads, and protect equipment.

- Indication of HTF flow is crucial for automatic flow control of the HTF system. Varying degrees of success have been reported by participants of this project. Due diligence with suppliers and discussions with other plant personnel with experience on this matter are crucial to ensure success.

- Estimations of HTF flow have proven reliable and consistent when using VFDs, pump amps, and system pressure drops. These methods of determining HTF flow can be used as an alternative of HTF flow meters in some instances; however, the accuracy of these methods is typically not nearly as good as a working flow meter would be. A reliable and accurate flow meter is still preferred.

- Proper insulation and heat trace are critical for HTF instrumentation. Instrument legs (HTF and water) have become frozen due to improper heat trace or other technology to avoid freezing. Production losses are likely without proper freeze protection. This is generally not a design issue but is more about finishing the project. Better coordination with supervision and construction representing the owner's interest (i.e., QC) is important.

- Common instruments (brands and styles) should be used throughout the plant. The OTS should specify and the EPC should implement standardization of instruments, even on skids.

- Local availability and serviceability for instrumentation is crucial for maintaining high availability. Maintaining adequate spares onsite is also recommended.

5.4.6 Auxiliary HTF Heater

Auxiliary HTF heaters have had issues with reliability, proper sizing, and proper system design to optimize the use of the heater.

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Background

Natural gas heaters have typically been installed at parabolic trough plants, primarily to prevent the HTF from freezing at about 12°C. In some projects, the heater has also been used to supplement/augment power generation. In general, the heaters were not reported to have many reliability issues other than the mention of a couple fires/explosions; but we believe that there may have been more issues. One of these was reported by a project participant at a newer facility, and the other occurred at one of the SEGS plants early in the project when a new style of heater burner was being used. Details are limited to the cause of the former incident. Some plants have reported operational issues with the heaters, but these details were also limited.

Another likely unanticipated use of the heater is to keep the HTF at a hotter "cold" temperature; the purpose is to ensure enough volume of HTF in the expansion vessels to provide pump suction of the HTF pumps. Due to the density changes of HTF from its cold to hot temperature, this strategy has been used to put off or limit HTF purchases. Whether this is the most economic approach is not known, but this strategy can keep a plant operational with low levels of HTF. Two participants have mentioned that they are currently using this strategy.

For cases of power generation, the importance was mentioned of having a bypass around the solar field. This can provide hot HTF directly, rather than going through the solar field, which may cool the HTF in cloudy conditions. It was also noted that the sizing of the heater is important and that having enough energy to maintain the turbine online should be the minimum requirement. This would allow plants able to supplement with gas to stay online through cloudy periods and avoid delays with starting up the unit again.

Other considerations for the heater include support of cold start-ups of the plant by making sure the turbine reaches warm conditions before sunrise, and cooling down and heating up big pieces of equipment during shut-downs (TES heat exchangers and SGS). For cooling down, the HTF would flow through the heater with the fan on, but the burner off.

Best Practices

- Due to the potential of the heater to explode, due diligence is required on the specification, purchase, and operation to avoid this kind of incident. A solid track record in a CSP or similar application would be preferred. New unproven designs should be considered with caution.

- The heater design needs to be sized and configured appropriately for the intended operating scenarios. In some cases, this has not occurred.

- The heater system design should have an option to either send flow to the solar field or bypass the solar field and go directly to the SGS. This can help with power production and maintaining heat in the SGS, which may assist with gland steam supply.

- If being used for power generation purposes, the heater should be designed larger than the minimum capacity to start up and maintain minimum load on the turbine. Using the heater can avoid shutting down and then restarting the plant in cloudy/transient conditions. The heater can also be used for testing the plant after an outage has been

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performed, if cloudy. This will help ensure that the plant is ready to operate as the sun returns, and it may optimize PPA outage requirements.

- Large capacity payments for purchasing power from utilities may also be avoided and/or reduced with this heater running at minimum loads during the appropriate/contract timeframes. The time-of-use and capacity payments for purchasing power will need to be reviewed prior to implementing this type of strategy.

- Depending on the criticality of the heater—which could vary by plant design, operating scenarios, and conditions (ambient and HTF volume)—use of an alternate fuel (e.g., dual fuel burner) may be considered.

- Consider the ability of using multiple fuel sources. This may be a factor of many variables, including criticality of having the heater available and reliability of infrastructure for fuel supply.

5.5 Thermal Energy Storage System

Thermal energy storage is a more recent development for parabolic trough technology. The TES system for parabolic trough plants is a derivative of the two-tank TES from molten-salt tower technology. Molten-salt TES was demonstrated successfully in the Solar Two pilot demonstration molten-salt tower project in the 1990s. In the early 2000s, a joint US/European team adapted this concept for the indirect two-tank molten TES used in trough plants by adding an intermediate heat exchanger to transfer thermal energy into and out of the molten-salt storage system. This concept was first used commercially in 2007 in the Andasol I project in Spain. To date, about 31 parabolic trough plants are in operation around the world with between 3 and 10 hours of TES. There are twenty 50-MW trough plants in Spain alone with between 7 and 9 hours of TES.

The operational record is fairly short for TES, but the general sense is that most of the TES systems in operation around the world appear to be operating well. However, there are several very important exceptions, and some important lessons have been learned as a result.

Figure 5-5 is a photo of a 50-MW parabolic trough plant in Spain with some of the main features of the TES system shown in the foreground.

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Figure 5-5. 50-MW Termosol 1 Plant with 9 hours of indirect molten-salt thermal energy storage (Spain)

5.5.1 TES Storage Media—Molten Salt

All plants to date have used the Solar Salt 60:40 mix of sodium and potassium nitrate salts for the storage medium. The grade and quality of the salt used has several important implications on the design of the TES system.

Background

Solar salt can be used over a temperature range of 260°C to about 575°C, well above the 390°C maximum that salt might see in a trough plant. As temperature decreases, the salts start to crystallize at 238°C and solidify at 221°C. Care must be taken to design the system appropriately for the grade of salt constituents used. The chloride fraction in the salt is important for determining corrosion rates. A report by Sandia National Laboratories documents expected corrosion rates for a range of temperatures and chloride percentages.[26] In general, to date, chloride corrosion does not appear to have been a major problem, in part because salts with low chloride contents have generally been used (Cl < 0.1%). Salts tend to include a number of inorganic impurities. Even small fractions of impurities can mean large volumes of impurities precipitating out at the tank bottoms or in other undesirable locations such as piping, valves, heat exchangers, or pumps. In addition, magnesium is often an impurity, which reacts over time to produce NO_x. Specifically, the magnesium ion in magnesium nitrate is more chemically active

[26] Robert W. Bradshaw and W. Miles Clift, "Effect of Chloride Content of Molten Nitrate Salt on Corrosion of A516 Carbon Steel," SAND2010-7594, November 2010.

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

than the sodium ion in sodium nitrate or the potassium ion in potassium nitrate. At relatively low temperatures (380°C–400°C), the magnesium ion will chemically reduce the nitrate ion, forming magnesium oxide as a solid precipitate and oxides of nitrogen in the form of a gas. NO_x is generally produced during the initial melting of the salt and over the first year or so. Salt is typically supplied in constituents in super sacks (~ 1.2 tonne bags) and mixed when melted. The melting system is usually a temporary system that is brought on site during construction and removed after melting.

Best Practices

- Use salt constituents that have a total chloride concentration below 0.1%. This significantly limits the corrosion rates.
- Minimize impurities and remove them, if possible, during melting.
- Design the system to manage NO_x generation during melting and over the life of the plant, as appropriate. Options for capturing the NO_x emissions include (1) reaction with water to form nitric acid, followed by neutralization with a base, and (2) adsorption in an activated carbon bed, followed by disposal or regeneration.
- It has been shown that the bags should not be stored on site for a long period of time, so that they do not absorb moisture and solidify. Long-term salts become rock hard and can only be handled and melted with great effort.

5.5.2 TES Storage Tanks

The TES storage tanks are unique, in a sense, due to the high temperatures at which they operate, the daily temperature cycling they see, and their size. There are no standards for this exact application; thus, extra care is required to make sure that the tanks are designed appropriately.

Background

Most operating plants have two TES tanks—one for cold salt and one for hot salt. Plants with large thermal storage capacities may have multiple hot and cold tanks. The storage tanks in a trough plant are like the cold-salt tank in a molten-salt tower plant. Because the maximum operating temperature is below 400°C, the tanks can be made from carbon steel. Grade A516 carbon steel has been shown to work well. It is important to design the tanks with appropriate corrosion allowances.

The tanks are designed to API Standard 650, Welded Steel Tanks for Oil Storage. However, this standard only considers design temperatures up to 260°C. For higher-temperature service in solar projects, the design methods in the standard are combined with the allowable material stresses from Section II of the ASME Code. The tanks are sized to hold the full inventory of salt—just in case maintenance is needed on one of the tanks. The tanks need a minimum heel level of salt to keep the impeller of the salt pumps submerged, and this also allows the bottom of the tank to be maintained at a more uniform temperature. It would be desirable if a new standard was created for salt tanks operating at CSP temperatures.

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Due to the size of the tanks, they are manufactured on site. As a result, quality control of the welding of the tanks is essential.

The foundation of the tanks is very important. The foundation must be insulated to minimize heat losses from the tank; but some heat loss or cooling is required to make sure the concrete and soil under the tank does not overheat. If the concrete is overheated, it can lose strength. If the soil is overheated, it can become desiccated, which would cause the tank to settle. Also, it is important that the temperature of the ground around the tank does not become a safety hazard for plant personnel. Additionally, the tank expands and contracts as it is heated and cooled. So, it is very important that the floor of the tank and the foundation are designed to handle the normal expansion and contraction of the tank experienced in daily operation and under any abnormal operation that the tank may be exposed to. Some projects have used sand or other materials under the tank to reduce the friction between the tank and the foundation. However, the concentrated weight of the wall and the roof can cause the perimeter of the tank to settle into the sand, or alternately, into the expanded clay that comprises the foundation insulation, either during construction or during normal operation following thermal expansions and contractions. As such, various approaches have been adopted to strengthen the perimeter of the foundation. Steel plates have been added under the wall of the tank to help distribute the load.

Several projects have reported salt tank leaks in the floor of the tank. Some of these are in the hot-salt tank at central receiver plants. These tanks are fabricated from stainless steel and may not be relevant to trough plants. But at least one trough salt tank has experienced a leak in the floor of the tank. In general, there is still relatively little long-term (i.e., decade) operating experience with molten-salt tanks.

A couple of approaches have been used to minimize the amount of salt in the heel of the tank, which is unused capacity in the tank. Some plants have used sloped tank bottoms and others have used tanks with internal pump sumps. The tanks experience daily expansion and contraction of the floor and tank walls. As such, we recommend that caution be used in designing the tanks. Given the general concern over the foundation and floor of the tank, we recommend that none of these types of approaches be used until the long-term performance of the other approaches is fully understood.

It is necessary to preheat the tank prior to introducing salt. Typically, propane or natural gas is burned in a heater and the exhaust gas is piped to flow through the tank. Combustion gases contain a fair amount of moisture, and the water vapor can combine with carbon dioxide to form carbonic acid. At temperatures in the range of 80° to 90°C, the acid can condense on the inside of the tank, which causes additional corrosion in the tank that must be accounted for in designing the tank.

Salt tanks have experienced leaks and have needed to be drained for inspection and repairs. One participant suggested that tanks should be designed and built with the ability to completely drain the tank to save time should the need arise.

The tanks in trough plants are typically blanketed with nitrogen to prevent a potentially explosive mixture in the tank should there be an oil leak in the HTF-to-salt heat exchanger. Most plants include an equalization line between the head space of the two tanks to allow nitrogen to travel

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between the tanks as the storage system is charged and discharged. This significantly saves on the amount of nitrogen consumed by the TES system. The equalization line needs to be heat-traced at all times to prevent salt buildup in the pipe and to prevent condensation of gases that would corrode the pipe.

Tanks should include VOC analyzers to detect for HTF leaks and prevent the potential for an explosive mixture in the tank. Not all VOC analyzers have proven to be reliable. Make sure any VOC analyzers selected have a proven track record.

Salt tanks require heaters to make sure the salt inventory can be kept above the freeze point during outages or low solar periods. There have been two approaches used for heating the tanks. The first is to use electric insertion heaters in the tank. These must be installed near the base of the tank in the salt heel. The second approach is to use an external heater. These can either run on the main salt pumps or use a separate pump circulation loop. The heaters can be electric or fossil-fired heaters. The insertion heaters have the advantage that no pumps need to be turned on to use them. The external heaters have the advantage that the heated salt can be introduced through a sparge header to encourage mixing at the base of the tank. The external heater also has the advantage that it is easier to add heating capacity after the plant is constructed if thermal heat losses are found to be greater than originally estimated. The choice of approach is up to the designer. We tend to like the external heater approach.

Best Practices

- The tank should be designed by an experienced TES tank designer. The tanks are designed to API Standard 650, Welded Steel Tanks for Oil Storage. However, this standard only considers design temperatures up to 260°C. For higher-temperature service in solar projects, the design methods in the standard are combined with the allowable material stresses from Section II of the ASME Code. Grade A516 carbon steel has been shown to work well. It is important to design the tanks with appropriate corrosion allowances.

- Make sure the tank design uses an adequate corrosion allowance to account for chloride content of salt and corrosion that occurs during initial preheating of the tank.

- Implement a corrosion monitoring program during the life of the plant. This could take the form of corrosion coupons suspended in the tank, or ultrasonic measurements of the tank wall thickness.

- Conduct 100% QC of welds. This requires the following:

    - The services of a full-time welding inspector, who has the authority to instruct the repair of any weld deemed suspect.
    - Radiographic examination of all wall and roof welds, and vacuum-box and dye-penetrant examination of all floor welds.

- Use a conservative design for the floor; i.e., the thickness of the floor must provide adequate resistance to buckling when the tank, near its maximum liquid level, undergoes an increase in inventory temperature.

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- Use a proven design for the foundation of the tank. The perimeter of the foundation must be sufficiently rigid to maintain the floor as a flat plane. Further, the foundation must provide a uniform coefficient of friction across the entire floor area.

- Avoid complex approaches, such as a tank-within-a-tank and sloped floors, to reduce the volume of the salt heel in the tank.

- Design the ability to completely drain the tank for inspections and repairs, if necessary. This might involve including a capped valve at the base of the tank near the floor-to-wall connection. This connection could be used to tie in a system for draining the tank in the future.

- Some form of VOC control system is needed for purging nitrogen blankets from tanks to capture VOCs from HTF that has leaked into the salt system. Some plants have used carbon filters, but a thermal oxidizer may be a better solution.

- The tanks in trough plants are typically blanketed with nitrogen to prevent a potentially explosive mixture in the tank should there be an oil leak in the HTF-to-salt heat exchanger. Most plants include an equalization line between the headspace of the two tanks to allow nitrogen to travel between the tanks as the storage system is charged and discharged. This significantly saves on the amount of nitrogen consumed by the TES system. The equalization line needs to be heat-traced at all times to prevent salt buildup in the pipe and to prevent condensation of gases that would corrode the pipe.

- Tanks should include VOC analyzers to detect for HTF leaks and prevent the potential for an explosive mixture in the tank. Not all VOC analyzers have proven to be reliable. Make sure any VOC analyzers selected have a proven track record.

- In one plant that has had issues with leaks in the HTF-to-salt heat exchanger (where leaks resulted in HTF leaking into the salt tanks), a distillation system was designed to cool the nitrogen vented from the TES tanks and to collect liquid HTF. This system was used to monitor the amount of HTF leaking into the tank. By measuring the amount of condensate HTF and the nitrogen flow passing through the condensate vessel, an HTF concentration can be estimated.

5.5.3 Oil HTF-to-Salt Heat Exchangers

The oil-to-salt heat exchanger is one of the most critical elements in the trough TES system. Just behind the salt, the heat exchangers are the most expensive component in the TES system. The design and construction of the heat exchanger is important from a performance and reliability standpoint.

Background

In the Figure 5-5 photo, six elevated heat exchangers can be seen between the two tanks. The heat exchangers use hot HTF to heat salt to charge the TES; then, they are used to discharge the TES, using hot salt to reheat the HTF. The heat exchangers are elevated so that they can be fully drained back into one of the salt tanks for long-term hold or to perform maintenance on the heat exchangers.

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In some cases, the heat exchangers have been mounted above the storage tanks to allow them to be drained to either tank. This ensures with certainty that all the salt has been removed from the system. Other approaches have installed the heat exchangers at a level that allows them to be drained by gravity into one tank or the other. Finally, some plants have installed the heat exchangers close to ground level, but require a separate drain tank below the heat exchangers that can be used to drain them if repairs are needed. Elevating the heat exchangers provides the most safety and lowest risk, but it also incurs the most cost.

Several different types of heat exchangers have been used or proposed.

- U-tube/straight-shell design: Most plants have used conventional U-tube/straight-shell heat exchangers with reasonable success. To achieve tight approach temperatures between the oil and the salt, multiple (typically six) heat exchangers are used in series. These designs appear to be robust and able to handle the daily thermal gradients that are experienced during start-ups. But they require a fair amount of piping and heat trace in between the heat exchangers.

- Floating-head designs: Several plants have used floating-head heat exchangers. This has the advantage that tight approaches can be achieved with fewer heat exchangers in series. Plant designs typically only require three heat exchangers, and these also appear to be performing well. Nonetheless, these are very large heat exchangers, and they can be difficult to transport. Also, each heat exchanger has up to twice as many tube-to-tubesheet connections as a U-tube/straight-shell design, so QC during manufacture becomes very important.

- Plate heat exchanger: A plate-style heat exchanger was used at several plants. The plate heat exchanger allows a large amount of heat-exchange area in a relatively small volume. A single-plate heat exchanger was used to replace multiple shell-and-tube heat exchangers in series. The plate heat exchanger demonstrated very good heat transfer and tight temperature approaches. The allowable rate of temperature change for the plate design is only 1.5–2 °C/min. This limit is restrictive for a plant that operates through daily thermal cycles and cloud transients.

- Header-coil design: The header-coil heat exchanger has been used as the oil-to-salt heat exchanger in several projects and has shown excellent reliability. The header-coil design can tolerate rates of temperature change about 20% higher than more conventional shell-and-tube designs (i.e., 12 °C/min versus 10 °C/min). Also, the tube-to-header connections use only welded joints, which eliminates one common source of leaks—i.e., the friction connection between the tube and tubesheet in U-tube/straight-shell and floating-head designs. It can achieve good approach temperatures; thus, fewer heat exchangers may be required in series. So, it appears to be a good robust option.

One of the main issues raised by participants has been tube-to-tubesheet leaks during initial commissioning of systems. Some of the problems can be traced to poor QC during the tube-expanding and strength welding operations. However, poor process control over the rates of metal temperature change during transient conditions has contributed to relaxation of the friction connections between the tubes and tubesheets. Although some plants have used carbon-steel tubes in the heat exchangers, we have concerns about the lifetime of these tubes due to chloride corrosion, especially for the heat exchangers at the hotter end of the series of heat exchangers.

Best Practices

- The engineer should create a process design that is able to limit the thermal gradients to the values specified by the heat-exchanger vendor.
- Robustness of the TES system design should be a priority over efficiency. Shell-and-tube heat exchangers have proven to be more robust than current plate-type designs, and header-coil designs have been shown to be very robust in this application.
- It is recommended to have a robust equipment automatic protection scheme programmed in the DCS to ensure that:
    - Maximum casing and fluid temperature gradients are respected,
    - Maximum temperature differential among fluids are respected,
    - Maximum flow-balance deviations are respected, and
    - Maximum flows and pressures are respected.
- Use experienced vendors who understand the process conditions. Do not try to save money with unproven suppliers. It is likely to be more costly in the long run.
- Good quality control and supervision by the owners and EPC team is essential during the manufacture, transport, and testing of the heat exchangers. This should include both conscientious QC during fabrication and adequate testing of the heat exchanger before installation. The specification should define the testing required.
- Make sure all materials have appropriate corrosion allowances. In the case of tubes, which normally do not have a corrosion allowance, the material must be selected to provide adequate corrosion resistance. For those tubes operating at temperatures above 350°C, the recommended material is Type 304L.

5.5.4 Salt Pumps

It is important that the TES pumps be reliable. Long-shafted turbine pumps inserted through the roof of the storage tanks are typically used for trough TES applications.

Background

The salt pumps are long-shafted turbine pumps, with the shaft bearing lubricated by the salt. The pumps are mounted above the tanks on a separate structure and inserted through the roof of the tank. This approach eliminates the need for separate pump sump tanks (as were used at Solar Two). The primary advantage is eliminating the need for control valves feeding the pump sumps. The potential failure of these valves could lead to a leak that could flood the sump and potentially cause a major salt leak. Initially, there was concern with bearings and vibration on pumps with long shafts (12 m or more). But pumps from several vendors have worked well and seem to be more reliable than control valves.

The difference between the hot-salt and cold-salt temperatures is only about 100°C, so the approach temperatures between the salt and HTF are very important. Because the HTF flow through the salt heat exchanger will vary with solar conditions, it makes sense to use VFDs on the salt flow circuit to allow fine-tuning of the approach temperatures. This can be true for both charging and discharging of TES.

In general, plants have not reported major issues with long-shafted salt pumps. Some participants have had issues with installation and alignment of long-shafted salt pumps. In one case, the platform holding the salt pumps above the tanks settled unevenly, causing some misalignment of the pumps. Long-shafted pumps also require some level of care when removing the pumps from the tanks or installing the pumps in the tanks. Specifically, the vendor will specify the rate (m/h) at which the pumps can be removed or installed. When possible, it is desirable to have installed spares so that pump maintenance will not result in a loss of TES availability.

Best Practices

- Use pumps from vendors with good demonstrated experience.
- Use variable-frequency drives on salt pumps.
- Properly install pumps to avoid settling and assure pump alignments.
- Installed spare pump capacity is recommended.

More information on molten-salt pumps can be found in the Molten-Salt Tower section.

5.5.5 TES Process Design

The process design of the TES system is very important. Special consideration should be given to start-up and transient operation conditions. However, there are also many other important design considerations such as: the change in temperature from ambient to operating conditions, diurnal temperature cycling of the system, freeze prevention of the salt, and the potential for HTF leaks into the salt piping.

Background

Care needs to be taken in the salt-process piping design to consider the expansion and potential movement of the tanks and other equipment. Pipes need to be sloped to allow all salt piping to be drained when maintenance is required.

During the morning start-up and the transition between solar and TES operation, it can be difficult to control the mass flow rate of HTF to the TES heat exchangers due to the large change in the volumetric flow rate of the HTF in the solar field and other equipment. This becomes even more complicated in larger plants that have multiple SGSs and TES units. One plant indicated that it was best to set the HTF flow through the TES heat exchanger and to control the flow of salt with the salt-pump VFD to achieve the best approach temperature. Split-range control on the HTF lines could help improve control of HTF flow rates during start-up, transition, and normal operation.

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Several plants indicated that improvements were needed in automation of the TES system operation. This is more difficult on large plants with multiple TES units.

Sparge headers are used in both the cold tank and hot tank to introduce salt into the tank. These units are typically designed as a ring header at the base of the tank to encourage mixing at the bottom of the tank. The goal is to provide mixing of salt at the bottom of the tank. Two plants have experienced issues with their sparge headers that have been credited with causing leaks in the tanks due to improper design or installation.

Two types of heating systems have been used. The first system uses bayonet heaters installed into the tanks. These use four or more heaters spaced around the perimeter of the tank and inserted toward the center of the tank. The amount of heating is limited by the maximum sheath temperatures on the heaters, which, in turn, are limited by natural-convection heat-transfer coefficients from the heater to the salt inventory. It is likely still necessary to have circulation in the tank to mix the heated salt with the bulk salt inventory. The second type of heating system uses an external heater, which typically requires a separate salt flow circuit and pump. The bayonet heaters offer simplicity but add potential risk for leaks. The external heating system adds risk related to complexity and availability.

It is likely at some point that oil HTF will leak into the salt through the heat exchanger, and the salt piping and tanks must be designed to account for this. The tanks are typically blanketed with nitrogen to prevent an explosive atmosphere from occurring in the tanks. The same considerations need to be considered for the heat exchangers and piping. If HTF leaks into the salt, the salt is at low pressure and the HTF is likely to vaporize. Salt piping should be designed considering that HTF vapor could be trapped in high spots. This is especially important when considering heat-trace circuits; there could be zones where a portion of the piping has HTF vapor and part has salt. Care must be taken to avoid overheating piping sections with HTF vapor. Piping and equipment should allow HTF vapor to vent to the headspace in the storage tanks.

Several TES systems have installed coolers on the salt-tank nitrogen vent lines to condense HTF out of the headspace of the tanks. This type of system can be used to monitor HTF leak rates into the storage tanks.

Many TES systems in operation are manually controlled by an operator. Some TES systems operate with fully automatic control, and this is the preferred approach.

Best Practices

- The TES system should be designed properly with good and realistic specifications. Specifications should assume plant trips and realistic temperature gradients in design.

- The TES system should be designed to handle HTF at a reduced and fluctuating solar-field outlet temperature on partially cloudy days.

- Bypasses around the main HTF-to-salt heat exchangers should be close-coupled to prevent large dead legs of fluid that can make it impossible to control temperature gradients entering the heat exchangers during start-up.

- The TES system operation should be fully automated to eliminate the need for manual operator control.

- Flow meters have often been unreliable for automation of control. It is best to use approach temperatures for automation of the TES system.

- Design of HTF and salt flow circuits should consider whether split-range control circuits are needed to enable good control during start-up as well as during full operation.

- The piping design should account for HTF leaks into the salt from the HTF-to-salt heat exchanger that may vaporize. Piping design needs to allow for vapors to flow to the tank headspace and not build up in piping or equipment. Tanks should be designed to meet API 2000 requirements.

- In case of oil-to-salt heat exchanger leaks, coolers can be used to remove HTF vapor from tank headspace.

- Some design and operation best practices during the summer saturation months include:

    - Consider bypassing the high-pressure feedwater heaters while operating the power plant from TES to increase TES thermal capacity and increase power from TES, and
    - Consider using the cold tank to keep the solar field warm at night. This enables the plant to start up faster while the TES will already be fully charged.

5.5.6 Molten-Salt Valves

See the section on molten-salt valves in the Molten-Salt Tower section for best practices for molten-salt valves.

5.5.7 Heat Tracing for TES

See the section on heat tracing in the Molten-Salt Tower section for best practices for heat tracing.

5.6 Power Block and Balance of Plant

This section specifically addresses the issues and best practices associated with the items related to the power block and balance of plant for trough plants. This section discusses the steam-generation system; steam-turbine system; water treatment and chemistry; DCS instrumentation and automation; main generator system; main electrical system; and auxiliary cooling. These were topics specifically mentioned by participants of the project.

5.6.1 Steam-Generation System

Participants have highlighted the reliability of the steam-generation system due to leakages as a significant issue relative to plant availability and/or maintenance time and costs. Failures have been reported to have occurred in each type of the heat exchangers of the SGS (i.e., superheater, steam generator, preheater, and reheater). From the information gathered from participants, failures are generally believed to be due to: inadequate design for the actual process conditions;

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exceeding operational limits of the equipment; and, in more limited cases, poor water chemistry. It should also be noted that some participants reported relatively few or no issues with the SGS.

Background

The most common type of heat exchangers used for the SGS system are the U-tube/straight-shell design and, to a lesser extent, the header-coil design. In the case of flat tubesheet designs, the combination of thin metal sections (shell-and-tubes) connected to thick metal sections (tubesheets) can produce high transient thermal stresses. Similar effects occur in the header-coil design; however, the magnitude of the stresses can be lower due to the replacement of a relatively thick tubesheet with a relatively thin pipe section.

Issues related to the design of CSP heat exchangers have generally been stated by participants to be associated with the tube and tubesheet connections. The cyclic nature and high temperature gradients experienced during the operation of CSP plants stress the tube and tubesheet connection as compared to a non-cyclic application. This connection is generally a forced fit that relies on expansion to seal the tube/tubesheet connection. In addition, a seal weld is made at the tube/tubesheet connection. The cyclic nature of CSP plants tends to cycle and stress the force fit, which may eventually lead to cracking of the tube/tubesheet weld. This is believed to be a main cause of design-related failures of CSP heat exchangers. Tube failures were also noted. It can be noted that no leakage has been reported in the header-coil heat exchangers in commercial service.

Many of the issues noted with the SGS system, in general, are believed to be caused by the equipment being exposed to operating conditions not anticipated by the design. This stems from process conditions not being fully integrated into the design, operation of the equipment above specifications/limits, and/or lack of controls to prevent equipment damage. One participant noted that turbine trips were very damaging to this equipment, and there were limited means designed into the plant to protect the equipment during such events. Others reported that failures occurred as a result of poor oversight of the chain of delivery and QC of that process. Poor water chemistry is also believed to have contributed to some of the issues. Also, it has been noted that automated water-chemistry control systems with poor design, faulty instrumentation, and poor water-chemistry practices have resulted in equipment issues. Inadequate or incorrect manual operation during transient conditions has also contributed to SGS failures. It appears that some faults have been due to unfamiliarity with standard plant operating procedures and inadequate non-standard operating procedures for off-design conditions during transitions, warm-ups, and shut-downs (normal and emergency). It was also been mentioned that control-system configurations are not always adequate and can themselves lead to faults. Control systems were noted as having insufficient warnings/alarms such that operators could not correct potential issues before they occurred.

Outage time can be quite extensive for SGS-related repairs due to leakages. A week would be considered a relatively short time depending on the scope, which would include the cool-down, testing, repair work, and heat-up. The testing can take considerable time because it likely includes testing all tubes for leakage and the tube/tubesheet connections for failures—the sources of most failures.

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Initially, trough plants (SEGS) were built with a kettle boiler-type steam generator/evaporator. The kettle boiler integrates the evaporator and steam drum into one vessel. Often, due to fabrication limits on the size of kettle boilers, later projects started using recirculation evaporators. It was also believed that the recirculation evaporator would have improved reliability with temperature gradients during start-ups and cloud/load transients. However, the steam generators—whether using a kettle- or recirculation-type boiler—have had issues that are related.

Several participants shared experiences of preheater issues/leaks due to an inherent underrating of the preheater from a pressure perspective. The preheater has the highest-pressure demand of all the SGS vessels because it is located closest to the feedwater pumps and requires enough pressure to avoid water flashing in the vessel. The level within the steam generators is typically controlled by valves between the preheater and steam generator. In systems without VFDs for the feedwater pumps, participants have used and noted that pressure control valves for the SGS system have been problematic and unreliable with the cyclic behavior of CSP plants. These valves are typically located prior to the preheater inlet/downstream of the feedwater pump outlet and are exposed to one of the highest-pressure locations of the plant. This location also has a negative influence of lowering the pressure in the preheater, and thus, providing an environment in the preheater more suitable to flashing. A positive aspect to this configuration is that the preheater does not need to be designed for the full feedwater pump pressure. Some participants have noted issues with reliability of these valves because they are prone to be cut due to the cyclic service of the system. Generally, this system is designed with two valves arranged in a split-range configuration. Control of the pressure and steam-generator level becomes difficult as these valves wear over time. Steam-generator-level control valves become more erratic as their duty increases due to the leakage and erratic behavior of the pressure-control valves.

Several CSP plants were reported to have failed reheaters. The reheater has a significant delta temperature (delta T) associated with it that is similar to the same delta T of the preheater, evaporator, and superheater combined. The reheater is exposed to the largest delta T of all the heat exchangers; so, two reheaters (traditionally tube-and-shell heat exchangers) are generally used in series to address the delta T in steps. Participants using a hairpin concept (U-shell/U-tube) have reported no failures with this design. The hairpin concept is one single vessel designed to handle the large delta T.

Participants were also asked about their preference to having 2 × 50% or 1 × 100% steam generator trains. Overwhelmingly, the participants preferred the 2 × 50% scenario. However, one participant reported no issues with their 1 × 100% train, and another participant chose two trains due to concern over reliability issues of others' experience. Physical size may also be an issue using just one train on larger plants. It is believed by those that experienced failures that having two trains offered flexibility while limiting production impacts. With plants using storage, a single train could be used at a lower plant load, but for a longer period (extending into the night and early morning) than if using both trains, thus limiting losses to some extent. Also, due to the lower performance of trough plants during the winter, some participants have reported that strategically performing wintertime annual work on a steam train (e.g., safety testing/repairs, inspections, valve work) while the other train is in service can lessen the complexity and time of the annual plant outage when the plant is fully non-operational. This strategy can increase the plant's availability due to the shorter annual outage.

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Best Practices

- Better specifications and understanding of plant operation and process conditions are required for the design of the SGS. It is critical that this information be part of the OTS and final specifications of the EPC to the supplier. Mechanical and thermal design is critical, so the design should not just consider the design-point basis but should also consider the anticipated actual process conditions. Process gradients must be considered during the design phase. Start-ups, transients, and plant trips are very demanding on this equipment. Proper attention and realistic evaluation of the mechanical design performance in fatigue issues and cyclical conditions should be considered for the heat-exchanger design.

- Refined plant models that simulate actual plant operational scenarios and gradients from start-ups, transients, and plant trips should be used in the design process.

- The final design selection should consider value and not just CAPEX. If a design can offer improved reliability and faster start-ups, then this should be part of the decision process for considering the equipment.

- The EPC should have a QC representative auditing the factory work to ensure that the equipment is being built to the agreed-upon specifications. A critical task would be to pay particular attention to the tube-to-tubesheet or header-to-tube welding, heating during welding, and proper rolling of the tubes after welding to an appropriate depth. The owner should hold the EPC accountable for doing this.

- Oversight is required for all phases of the chain of delivery of SGS. It is important to oversee manufacturing, transport, layup, and commissioning/testing (per proper specifications) of this equipment.

- The SGS should be designed with a bypass for the HTF process, which reduces stress on the heat exchangers during the start-up process. The bypass should be coupled close to the vessels to minimize dead legs.

- It is critical for operations to stay within the equipment specifications of the SGS through properly designed DCS logic (warnings, alarms, and plant trips). The EPC/commissioning team/owners' operators should work together during commissioning to design and verify DCS logic. Operational issues/ramping concerns have been mitigated at older operating plants using DCS logic with warnings and alarms for process ramp rates.

- It is critical that O&M standard operating procedures are accurate and enforced. For the SGS, they should incorporate provisions for off-design conditions during transitions, warm-ups, and shut-downs (normal and emergency).

- Water chemistry should be considered in the design: proper water circulation of the bulk water and continuous blow-down/sample lines should be in the bulk water of the steam generator/evaporator.

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- A rigorous water-chemistry program should be followed by the party responsible for O&M. This program should be verified and adhered to, starting from the initial commissioning phases. If not followed, issues with heat exchangers should be expected later in the project. Industry-standard equipment should be used, along with grab samples, to verify their accuracy. Best practices for water chemistry are expanded on in the Water Treatment and Chemistry discussion in the O&M section.

- SGS equipment should be designed with consideration for maintenance efficiency. This could include access points for preventive and corrective maintenance and the use of studs with double nuts for flanges. Threaded nut holes are prone to damage/stripping and are time-consuming to remove/repair. Studs with double nuts can easily be cut out if necessary and replaced.

- Tube-sheet access and provisions that consider pulling bundles should be incorporated—i.e., track system, crane/equipment access, and laydown areas.

- VFDs on the feedwater pumps are preferred to eliminate the need of pressure control valves for the SGS. The preheater would need to be designed for full feedwater pump pressure without the pressure control valves.

- Pressure control valves could also be eliminated without VFDs for the feedwater pumps if the preheater was designed for full feedwater pump pressure. This design puts more stress and duty on the level control valves of the SGS than would occur if using VFDs for the feedwater pumps. In this case, the level control valves would have to be designed for this duty.

- If pressure control valves are used for the SGS, they should be quality valves that can withstand the duty and cyclic nature of the system. A split-range configuration (for low/high flow conditions) should be used.

- Level control valves for the SGS should be quality valves that can withstand the duty and cyclic nature of the system. A split-range configuration (for low/high flow conditions) should be considered.

- Allowance for greater variance/swings in water level in the steam generator should be considered. Often, level control instrumentation and/or inlet control valves can work erratically and may cause levels to swing. In kettle boilers specifically, high water levels risk water induction into the turbine, and low water levels may expose the tubes to high flux conditions. Quality high-level alarms should be used.

- Use three-element control (i.e., feedwater flow, steam flow, and level) of the SGS system to ease the burden of SGS level control on operators. A reliable control system could help reduce the required operations staff.

5.6.2 Steam-Turbine System

In general, steam turbines have adapted and performed relatively well moving into the CSP industry. In fact, some turbines have lasted beyond the 30-year "lifetime" of the associated

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projects. However, there have been notable concerns presented by participants of the project. Some of these concerns stem from design issues that were later discovered and led to significant repairs and modifications years into the project. In contrast, many turbines have performed well and without these issues. The other significant concern with CSP turbines is the start-up efficiency. This is a much bigger issue than just start-up curves and includes significant engineering support in piping lengths to/from the SGS, turbine bypasses, gland steam system, and different start-up strategies. CSP turbines generally operate in a sliding-pressure mode due to the transient conditions whereas traditional turbines run more in a constant-pressure mode.

Background

Many participants of the project were aware of and discussed issues related to final stages of turbine blading. Information presented to the Best Practices team is limited on the details of these issues, but two different prominent manufacturers have had two different types of issues with the final stages of blading. In the case of one manufacturer, it was believed that there may have been a tolerance issue such that the clearances were too tight between blades, which caused a frequency-related vibration to the blades that, in some cases, exposed the blades to cracking. Plant outages were required to inspect and make repairs, if necessary, on potentially impacted turbines.

For another manufacturer, a new design was used for the locking mechanism of the final stage of blading that had supposedly been modified for solar applications. A repair was necessary on impacted turbines that required a plant outage to replace/repair the final stage of blading/locking mechanism using a previous/proven design method.

Also known to the Best Practices team is one instance where a turbine rotor had cracked. It was temporarily repaired and eventually replaced. Details are limited because this participant did not participate in the Best Practices project.

Start-up efficiency was also a topic discussed with many participants. Responses varied about the adequacy of the start-up curves. In some cases, EPCs and owners were more engaged, working with the turbine manufacturer in controlling the plant process for optimization of the turbine curves. In these cases, the start-up curves were generally good at the beginning of the project. In other cases, the curves were modified later in the project in a similar matter with the owner working with the turbine manufacturer. Also relative to start-up efficiency is the piping design/length from the SGS to/from the steam turbine and turbine venting and bypass configuration.

With most other turbines, start-up times were improved without breaking vacuum by maintaining gland seals overnight. Gland steam is generally supplied by the steam generator, and in many cases, participants have mentioned that additional energy is needed to maintain this energy overnight. In some of these cases, an external heater has been added to the gland steam system.

One participant implemented a start-up using only the low-pressure turbine. It was their opinion that this was an optimal design and had the added benefit of not requiring gland steam overnight, i.e., vacuum was broken each night and resulted in no delay in the start-up.

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Heating blankets were also discussed among participants regarding their effectiveness to improving start-ups. Responses were mixed and not definitive. One participant believed that their turbine had a very thick case that allowed the turbine to stay hot and only needed better insulation rather than heating blankets. Another participant with a different turbine without the thickness also thought better insulation would be desirable. Optimization of insulation/heating blankets will depend on plant configurations (TES hours), turbine design, and operating strategies.

In one instance, it was believed that foundation settling early in the project led to turbine vibrations that eventually were significant enough to prevent synchronization. A realignment of the turbine corrected this issue.

Alternate configurations were discussed with one participant using 2 × 50% turbines in lieu of 1 × 100%. In this case, the O&M team favored the concept due to added flexibility for achieving high availability even though it did complicate the operations.

Best Practices

- Reliability of the turbine is important. Owners and EPC should work closely with the turbine supplier to understand the proposed turbine design and its reliability and efficiency. Review the track record of the proposed or similar turbine—preferably in the CSP industry.

- It is important that the turbine supplier has accurate specifications to meet. These should include process design points, but also, expected plant process conditions during transients and start-ups. Thus, the supplier can optimize the design to start up efficiently. Consideration for turbine operation with high-pressure feedwater heaters bypassed should be considered.

- The EPC should work with the turbine supplier to design the optimal turbine-related system for optimal robustness and efficiency. This should include all the turbine-supplied components, but also, the optimizations of the system: piping configuration to and from SGS; bypasses and vents; gland steam system, insulation/heating blankets, jacking and lube oil systems.

- Discussions with the turbine manufacturer should start during early stages of development and engineering. Start-up times, variants, and additions to start-up curves, as well as different seasonal modes, should be considered in the design to optimize performance and lifetime. One approach is to have the steam generator and turbine vendors work together to determine how to achieve the quickest combined start-up times.

- Start-up curves may need to be optimized early in the project once operations/process conditions become steady and known. Start discussions early with the vendor on this matter.

- Turbine bypass location is important to decrease start times. Without proper location of bypass, steam must be vented (loss of water) and longer start-up times are incurred. The

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location of bypasses needs to be near the high-pressure and low-pressure inlets. Proper location can decrease start-up times by 20 minutes compared to improper location.

- The EPC should work with the turbine supplier to optimize the gland steam system. Most turbines benefit with start-up times due to maintaining vacuum overnight. As such, gland steam is used to maintain this vacuum overnight versus breaking vacuum each night. Most projects have limited gland steam supply (from the steam generator), and some participants have added an external electric heater to add superheat to the saturated steam supply to maintain vacuum longer.

- One facility noted no significant issues with the gland steam supply from the SGS during off-line periods due to each train having a main steam-block valve that is closed at the outlet of the superheater, with the gland seal supply taking off just before that. Many plants have tried to use the entire header as the source, and this causes a large loss of heat and pressure for the off-line time requirements. In some plants, gland steam heaters were added/considered later in the project.

- For reheat turbine configurations, evaluate with the turbine vendor if start-up efficiency can be done on the low-pressure turbine. This procedure has improved start-ups at some facilities and allows the plant to break vacuum each night without an impact. This salvages all the energy required to maintain gland seals at night. This gland steam system generally takes energy from the steam generator and may also use a heater in series/parallel to maintain the gland seal each night. Saving energy in the steam generator improves the start-up, but running an external heater has a monetary expense.

- Some turbine casings are much thicker than others and have the advantage of holding heat much better, and they likely improve start-up times. This should be considered in the selection process. This design will likely extend cold start-ups.

- Heating blankets and/or thicker insulation may improve start-up times. This should be part of the design process to determine the cost payback of adding this additional expense for a plant. This part of the process should be integrated with start-up curves based on expected process conditions.

- One facility worked with the turbine vendor and modified the turbine operation for low-load cloudy periods by eliminating the steam from the high-pressure steam inlet during that condition. The unit can run for about 1 hour with just low-pressure steam, with much lower steam quality than is necessary for high-pressure steam. This type of operation could allow plants to stay online longer during cloud transients.

- The lube oil system should be specified to be inside the turbine building due to typically hot and dusty environments.

- Redundant jacking oil pumps should be considered due to the amount of time a CSP turbine typically stays on turning gear.

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- Full-load steam-bypass capacity around the turbine to the condenser is preferred for water savings.

- QC during construction is important, e.g., even turbine (and other equipment) foundations have settled, causing equipment issues.

5.6.3 Distributed Control System / Instrumentation and Automation

Numerous comments have been made by participants regarding concerns of the DCS systems. In many cases, the observed deficiencies of the DCS begin during commissioning—and even before, with inadequate specifications. System functionality including alarm management and control logic is often inadequate and needs to be carried on far into the O&M phase until the system is adequately tuned. An inadequately tuned system typically will require more attention from operations and likely additional staff to oversee; and it is generally used in a more manual mode, not taking advantage of the capacity of the DCS system and potential automation.

Background

One of the most noted points made by participants was regarding alarm management. Often, plants have too many alarms, which become just nuisance alarms (i.e., ignored because there are so many). This makes it difficult for the operator to prioritize critical alarms and operate the plant to an acceptable standard.

Control logic and DCS schemes are often not devised well and fail to include voting logic (methodology to determine process value when redundant instruments are used) and trip criteria. Uncertainties in instruments cause operators to be unsure how to operate and often lead to manual operations that override the automated schemes. Trip schemes based on a single instrument reading have been reported to occur. This is an oversight in the control-system design and the plant instrument specifications.

In some noted instances, three-element control of SGS has worked poorly and led to excessive attention for maintaining water levels and often resulted in oscillations in the turbine output. Three-element control uses feedwater flow, steam flow, and level to ensure proper level in steam drums. Without this common industry-standard scheme in place and reliable instrumentation, more attention and manual control from operations is required and possibly additional staff.

DCS configurations range considerably from plant to plant. Most typical is one control system being responsible for the solar field, another for the turbine system, and another for the balance of plant, including the TES. In some cases, the balance of plant and turbine control system are combined. Product support and integration issues were reported by using various systems, especially ones that were specialized and more unique.

It is also generally common to have different DCS platforms for the water-treatment plant, heat-tracing system, and fire system, for example. Often, the central control stations are placed in different areas of the plant and not in the common control room where the main plant DCS is located.

The solar-field control system generally is the most specialized and unique. Typically, these are not industry/commercial standard systems and may not have industry-standard specifications and

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displays. In some cases, it was noted that obsolescence of the system or overreliance on one programmer were concerns.

Automation of plant systems has had mixed success according to participants; in general, however, it is believed the automation is underutilized and has not achieved a mature level. The automation schemes are generally not well defined, and their poor implementation results in the plant being run in a more manual control mode. Typical automatic functions would include SGS level and load control, HTF flow/temperature control for the solar field/SGS, and incorporated with storage systems with those that have them. Automation has the potential to reduce staff and protect equipment if designed and implemented correctly.

Problems have also arisen where different companies may have responsibility over different areas, i.e., solar field, TES, and power block. In such circumstances, each of these companies may understand their own systems very well, but not the integration into others. As a result, the company responsible for DCS has only a limited overview, and it incorrectly prioritizes the importance of control loops in other areas.

Best Practices

- Input and expertise from O&M SMEs should be considered for selecting DCS systems for the project including the solar-field control system. Specifications should be reviewed by these SMEs to ensure that the specifications meet operational requirements and that the system will meet long-term needs of the project, i.e., support. Consider a single integrated system for all major control systems. Local skilled programmers are necessary to keep the system optimized and maintained.

- An open-architecture system that is widely available (in the local market) should be considered. There is a need to collaborate with people knowledgeable in the local market and to partner with them.

- Input from O&M SMEs on the detailed functionality specifications should be considered. At a minimum, this would include control schemes, alarm management, automated systems, screens, and user interfaces.

- Factory acceptance testing of the DCS is important. O&M operator(s) and/or SME(s) should witness and be a part of this functional testing.

- Prior to COD, consider a required test of the DCS system to ensure that:
    - The alarm system meets a minimum readiness criterion.
    - DCS screens are fully completed and meet the specifications/expectations.
    - Key control loops are working. The plant can be operated as per the operation procedures.
    - There are no forced signals.

- DCS logic, control schemes, and automation should be designed with the goal of limiting operations requirements and staffing while also protecting equipment.

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- Some participants have commented that the O&M team has continued to make improvements to the equipment control systems since commercial operation date. This should be anticipated.

- Instrument issues have been problematic with reliable DCS functionality. It is recommended that instruments be specified to a standard brand for all instrumentation, even on skids; consider standard equipment over specialized equipment and consider availability/service for the long term.

- Using three instruments with two-out-of-three voting logic should be implemented any time a single point can cause the DCS to trip the plant or potentially cause other equipment damage with a control change. Single instruments have been used for turbine protection, as an example, such that a single glitch can cause a turbine trip.

- Automation of key systems has been mostly problematic according to participants. Issues with SGS level indications and steam flow meters have made it difficult for three-element control of the SGS system. HTF flow meters have made it difficult for automation of HTF systems (HTF flow meter reliability is discussed in the HTF system section). Erratic valve operation has been noted as problematic by some participants. Quality instruments proven in CSP-related services should be considered.

- Automation of HTF flow is critical for both optimization of performance and protecting equipment. With the large solar fields of today, TES systems, and complicated piping configurations, it is vital to take measures in the design to ensure a reliable automated flow scheme.

- Automation of HTF flow has other advantages: at some plants, it may allow just one person to operate the plant rather than one person for balance of plant and one for the solar field; HTF flow control stabilizes generation; and HTF flow control reduces parasitic losses.

- For HTF flow automation, transients require proper control in the solar field, TES, and SGS without exceeding limitations. These requirements must be designed into the automation logic and control.

- One participant reported that the HTF automation worked very well; they have been using a recently developed algorithm. This participant was planning to install this logic at some of their other facilities.

- Control-logic modifications of some systems—to achieve greater automation and to correct human errors during the operation—generally occurs from the commercial operation date. This should be anticipated.

- It is a good practice to have all DCS process control stations located in the main control room of the plant—not only the main DCS system for the plant, but others for the water-treatment plant, heat-tracing system, and fire system, for example.

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5.6.4 Main Generator System

Main generator reliability has impacted a few plants; but, in general, reliability has been rather high. The issues appear to be non-technology-specific and believed to be caused by inferior manufacturing.

Background

Typically, the main generator is supplied by the turbine manufacturer. In general, generators tend to be reliable due to their longevity in power generation, and the cyclic CSP operation does not influence this reliability.

One participant had two generators rewound due to bad-quality copper being used. Also, another participant reported issues with a main generator due to non-technology-specific reasons.

An issue brought up by one participant was that using a hydrogen-cooled generator was not recommended, primarily due to: a long 12-h purge time at the start of maintenance outages; considerable instrumentation; and dealing with the hydrogen supply. However, reliability was not an issue.

Best Practices

- The EPC should have a QC representative auditing the factory to ensure that equipment is being built to the agreed-upon specifications. The owner, through its OE, should assure that this is done.

- Consider an air-cooled generator over a hydrogen-cooled one due to the general complexity of maintaining the hydrogen systems at remote sites, which is an added complexity for O&M.

- Perform a routine-condition monitoring test of the generator, e.g., partial-discharge testing.

5.6.5 Main Electrical System

The most notable concerns with availability of the electrical system occurred due to transformer failures. One participant also noted reliability issues with the main generator breaker. The solar-field electrical system design was also noted as deficient and has potentially caused SGS damage as a result.

Background

Several of the transformer failures were catastrophic and due to an inadequately designed bushing for the application being installed on the transformer. This same faulty bushing had been installed in several other transformers that also failed catastrophically.

After some failures, the bushing manufacturer provided a notice suggesting that their product may not be designed appropriately for cyclic operations and noted both solar and wind applications. In addition, hot environments would further stress the bushing. It is known that some plants changed bushings after receiving this notice.

One participant noted significant reliability issues from the main generator breaker. The breaker was believed to be undersized for the application; after several attempts to replace components related to the connection-point apparatus without success, the breaker connection points were eventually modified to operate without further issues.

Emergency power reliability was not brought up with many participants, although one participant acknowledged limitations with their system. One issue was that the diesel generator took 45 seconds to provide power in case of a power outage from the grid. They had recently brought this time down to 10 seconds by reprogramming and reconfiguring the diesel generator. We noted that some participants never experienced grid-related trips whereas others did.

One participant noted a deficiency in the electrical design of the solar field. The UPS was designed to move only 20% of the field at a time, so it was decided to reduce the wiring size to the solar field by the same amount. As such, during regular operations or after a turbine trip, only 20% of the field could be moved, thus making it mandatory to maintain HTF flow while collectors were in the sun. A turbine trip reduced feedwater heating in this plant due to lack of turbine extractions and no means of sending attemperated main steam to the feedwater heaters. As such, the water temperatures in the SGS were suddenly quenched, which caused excess gradients on the SGS equipment. This was believed to be the main contributor to SGS issues of this participant.

Critical offline equipment in many cases did not provide provisions of redundancy and was susceptible to single-point failures on the motor control center (MCC). This also made outages more challenging with the electrical portion of testing/work.

Some plants have islanding capability. If the grid drops, they can go to minimum load, disconnect from the grid, and stay online.

A couple of participants mentioned that additional capacity in the transformers and MCC capacity should be considered in the design to support potential additions. Also, extra cables in the cable trays were a suggestion due to the ease of doing this work initially versus later.

Also mentioned was lack of decent lighting in the power-block areas to support O&M activities.

Best Practices

- Even with traditional equipment, specifications should be developed for the uniqueness of the operations of CSP projects. Equipment needs to be designed and built to withstand these unique operations. Some main-generator step-up transformers have catastrophically failed due to transformer bushings failures. These failures were identified as due to the cyclic and hot conditions to which the bushings were exposed.

- The electrical configuration of the plant and the solar field need to be designed such that plant trips are not causing equipment damage. Design needs to consider plant-trip scenarios.

- The emergency power requirements for the plant need to be well designed to protect equipment from damage when power is lost. One solution that has worked well for getting collectors out of the sun is using hydraulic accumulators for the solar-field drive units that move the collectors off focus without power requirements. Uninterruptable power supply systems have also been used at plants for this purpose and are sized to move the solar field—or typically, smaller portions of the field over several time intervals.

- Identify critical offline equipment and ensure adequate alternatives for single-point failure. Consider adding selector switches that will allow critical equipment to operate off different MCCs. Some items to consider include control oil pumps, turning gear, vapor extractor for lube oil, and gland seal exhauster. These items are in addition to standard items such as lube oil pumps.

- For project design, it was suggested to consider additional capacity for the transformers/MCC for more loads added later. Also, additional electrical cables should be considered for the cable trays during construction to support later possibilities. This consideration of extra cable would also apply to instrument wire.

- Lights in the power-block area should be considered to support O&M safety and activities. To maintain high availability, work is often performed at night in the power-block area. Appropriate lighting should be installed to support activities while limiting the amount of portable lighting required.

5.6.6 Auxiliary Cooling System

Use of open cooling for auxiliary equipment is prone to water-chemistry upsets and has potential for cross-contamination of systems.

Background

Auxiliary cooling provides water cooling for equipment such as: HTF pumps; feedwater pumps; generator air cooler; ullage cooler; expansion vessel cooler; and lube oil cooler. Open auxiliary cooling uses water from the open cooling system (cooling tower) as the process water. On the other hand, a closed cooling system uses a closed system of demineralized water that uses open cooling water to cool the closed cooling water with heat exchangers. Generally, the closed cooling system is more complicated and costly; however, a closed cooling system is separate from the open cooling system and allows for better water-chemistry control and is separated from any anomalies or impurities of the open cooling system.

In the one instance mentioned of a plant using an open auxiliary cooling system, a leak occurred in one of the HTF system-related heat exchangers and ended up contaminating the open cooling system (cooling towers) and evaporation ponds. With a closed cooling system, the contamination would have been isolated to just that system.

Best Practices

- A closed auxiliary cooling system is recommended to alleviate water-chemistry concerns through upsets and contamination from the open cooling system. Also, a closed cooling system is generally isolated from the open water system, which prevents contamination

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of the auxiliary cooling system moving to the open water system (cooling tower and evaporation ponds).

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6 Molten-Salt Central Receiver Tower Technology

6.1 Background and Introduction

In contrast to parabolic trough technology, which focuses sunlight on a line, central receiver technology focuses sunlight on a central point. The technology uses two-axis-tracking mirrors (heliostats), a tower located near the center of the heliostat field, and a heat exchanger located at the top of the tower.

6.1.1 Heliostats

The heliostat is an assembly of mirror modules located at the top of a pedestal that can rotate independently about both the horizontal axis and the vertical axis. Representative commercial heliostats are shown in Figure 6-1.

Figure 6-1. Both large and small heliostats are used in today's commercial power towers
Source: Crescent Dunes (large) and Ivanpah (small)

6.1.2 Receivers

The receiver is the heat exchanger located at the top of the central tower. The heat exchanger is typically constructed using metal tubes, through which a heat-transfer fluid passes. The fluid can be a gas, a phase-change material, solid particles, or a liquid. Over the past 45 years, prototype receivers have used compressed air, saturated water, superheated steam, sodium, solid ceramics, and nitrate salt as the heat-transfer fluids. Today, commercial projects use water/steam (Ivanpah, Khi, Ashalim; see Figure 6-2) or nitrate salt (Gemasolar, Crescent Dunes, Noor Ouarzazate III, Cerro Dominador, Delingha, and Dunhuang; see Figure 6-3) as the heat-transfer fluids.

Figure 6-2. Ivanpah water/steam receivers
Source: Google Images

Figure 6-3. Crescent Dunes nitrate salt receiver
Source: Google Images

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6.1.3 Plant Design Requirements

Heliostats

A commercial heliostat typically consists of several mirror modules mounted in a steel frame. The frame connects to a drive mechanism, and the drive mechanism is located at the top of a vertical pedestal.

The mirror modules are typically a second-surface, silver glass mirror. The modules are often fabricated with a slight spherical curvature. The modules are attached to the steel frame, and the positions of the modules are adjusted slightly (canted) such that the front surface of the heliostat forms a shallow parabola. The sunlight reflected from the heliostat is concentrated by a factor of 4 to 6 by the time the energy reaches the receiver surface.

The two-axis drive mechanism rotates the steel frame about a horizontal axis (elevation drive) and a vertical axis (azimuth drive). During normal operation, the pointing vector for the front surface of the heliostat bisects the angle between the sun and the receiver.

Imperfections in the mirror surface, deflections in the steel frame, and backlash in the drive mechanisms result in differences between the expected pointing directions and the actual pointing directions. The overall optical error is about 3 mrad for wind speeds below 10 m/s. The error increases for wind speeds between 10 m/s and 15 m/s. At wind speeds above 15 m/s, the heliostats are generally placed in a high-wind stow position. It should be noted that these wind-speed categories are only indicative; different sites will have different categories. For example, a plant in Chile will have higher wind-speed limits than a plant in Dubai; therefore, the heliostats will be physically different.

Receivers

Parabolic trough receivers use a glass envelope—with an evacuated space between the receiver tube and the envelope—to reduce thermal losses. In contrast, the heat-exchanger tubes in a central receiver do not use glass envelopes; i.e., the tubes are exposed directly to the environment.

Two basic receiver geometries are in commercial use:

- A cavity receiver, in which the absorber panels are placed on the inside surfaces of a box. The incident flux enters the box through an aperture. Short-wavelength reflections and long-wavelength radiation from each panel can be captured by the other panels, which reduces the reflection and radiation losses.

- An external receiver, in which the absorber panels are located on the outside of the support structure. Reflection and radiation exchange is no longer possible. However, the incident flux no longer needs to pass through an aperture. This generally allows a more uniform flux distribution across the absorber, which, in turn, allows a reduction in the absorber areas relative to a cavity receiver. Also, the absorber panels in salt receivers must be preheated to a nominal temperature of 50°C to 75°C above its freezing point (300°C for nitrate salt) prior to filling with salt. This can be achieved with an incident flux of perhaps 40 to 60 kW/m^2, depending on the wind speed. However, it is not

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possible to establish a flux this low and with this uniformity in a cavity receiver. As such, all salt receivers are external designs.

The thermal losses in a central receiver are reduced to commercially acceptable values by making the absorber area as small as possible, without having excess spillage. For a given power, a reduction in the absorber area necessarily results in an increase in the incident flux. The allowable incident flux is an optimization of the following competing effects:

1. A decrease in the absorber area results in an increase in the flux from the heliostat field that misses the receiver, either above the absorber or to the sides of the absorber. The flux not captured by the receiver is called spillage.

2. The incident flux on the receiver is absorbed on the front of the tube; the back of the tube is not illuminated. The incident flux profile around the tube establishes a temperature gradient around the circumference of the tube, and it establishes a temperature gradient through the wall of the tube. The two temperature gradients establish a strain gradient within the tube, with the highest strains at the crown of the tube. Strain levels are selected as high as possible, but consistent with a low-cycle fatigue life of 30 years.

Water/steam receivers operate at essentially the inlet pressure of the steam turbine—typically in the range of 100 to 165 bar. The high operating pressure requires relatively thick-walled tubes. The tube strains are nominally proportional to the tube-wall thickness, and the allowable peak incident fluxes for water/steam receivers are on the order of 600 kW/m^2 for the preheat and evaporation sections, 350 kW/m^2 for the superheat sections, and 150 kW/m^2 for the reheat sections. Typical tube materials include carbon steel for the preheat and evaporation sections, and ferritic steel for the superheat and reheat sections.

In contrast, the pressure of the salt in a salt receiver is set by the pressure drop through the receiver. A typical receiver inlet pressure is 20 bar, which allows the use of relatively thin-walled tubes. The thin-walled tubes allow a peak incident flux of about 1,000 kW/m^2. Commercial receivers use nickel-alloy tubes, such as Alloy 230.

Heliostat-Field Layout

There is a broad range of independent variables in designing the heliostat field and receiver, including: the heliostat radial spacing, heliostat azimuthal spacing, minimum radius of the heliostat field, maximum radius of the heliostat field, height of the tower, height of the receiver, and diameter of the receiver. To select the combination of parameters that provides the lowest cost of energy, one must calculate the annual performance and the corresponding cost of each combination. This requires an annual weather file, a calculation of the receiver efficiency as a function of the incident power, a calculation of the allowable incident flux on the receiver as a function of the time of the day and day of the year, the optical accuracy of the heliostat as a function of wind speed, and costs for the following: heliostats, receiver tower as a function of height, receiver as a function of height-to-diameter ratio and absorber area, riser and downcomer piping as functions of pipe diameter and tower height, and receiver HTF pump work as a function of flow rate.

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An optimization task of this complexity requires a computer program. Some optimization programs are available on a public basis, such as DELSOL3 from Sandia National Laboratories. However, most project developers use in-house proprietary programs, and they often employ ray-tracing techniques to calculate receiver flux distributions, spillage losses, shading losses, and blocking losses. An example of an optimized heliostat-field layout for a commercial salt-receiver project is shown in Figure 6-4.

Figure 6-4. Crescent Dunes heliostat-field layout for salt receiver
Source: Google Images

Thermal Storage

For plants using water/steam receivers, thermal storage is a difficult proposition. It is impractical to store large quantities of steam. As such, the energy from the steam must be transferred to a separate storage medium. To discharge the storage system, the energy must be transferred from the storage medium back to steam. This requires two expensive groups of heat exchangers. There are also thermodynamic losses in converting latent heat to sensible heat, and then converting sensible heat back to latent heat. The net effect is a unit cost for thermal storage that is greater than $150/kWh$_t$, and this is outside the realm of financial feasibility.

For plants using salt receivers, thermal storage is an obvious addition. Although the salt is a mediocre heat-transfer fluid in the receiver, it is an excellent thermal storage medium. The salt is inexpensive (~$800 to $1,000/metric ton, delivered), it has an extremely low vapor pressure (<20 Pa at 600°C), and it is chemically stable in the presence of both air and water. The low vapor pressure allows the salt to be stored in large tanks that resemble oil storage tanks, i.e., flat-bottomed tanks with a domed roof. The chemical stability in air allows the tanks to be vented

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directly to the atmosphere, which avoids the need for specialty cover gases. The chemical stability in water prevents the degradation of salt when exposed to water and steam leaks in the steam generator. For a 100-MW_e plant, at least 12 hours of thermal storage can be provided by a combination of one hot-salt tank and one cold-salt tank. The unit capital cost is on the order of \$40/kWh_t. An aerial view of the two-tank thermal storage system at Crescent Dunes is shown in Figure 6-5.

Figure 6-5. Two-tank thermal storage system at Crescent Dunes
Source: Google Images

Steam Generator

For plants using water/steam receivers, the receiver is coupled directly to the steam turbine, and the receiver is the steam generator.

For plants using salt receivers, energy must be transferred from the salt to produce steam at the conditions required by the steam turbine. The energy transfer occurs in a steam generator, which typically consists of four shell-and-tube heat exchangers in series: an economizer; an evaporator, with an associated steam drum; a superheater; and a reheater. The heat exchangers are normally constructed to the requirements of ASME Section VIII Division 1, Section VIII Division 2, and the Tubular Equipment Manufacturers Association. A conceptual equipment arrangement, showing two 50% trains, is illustrated in Figure 6-6.

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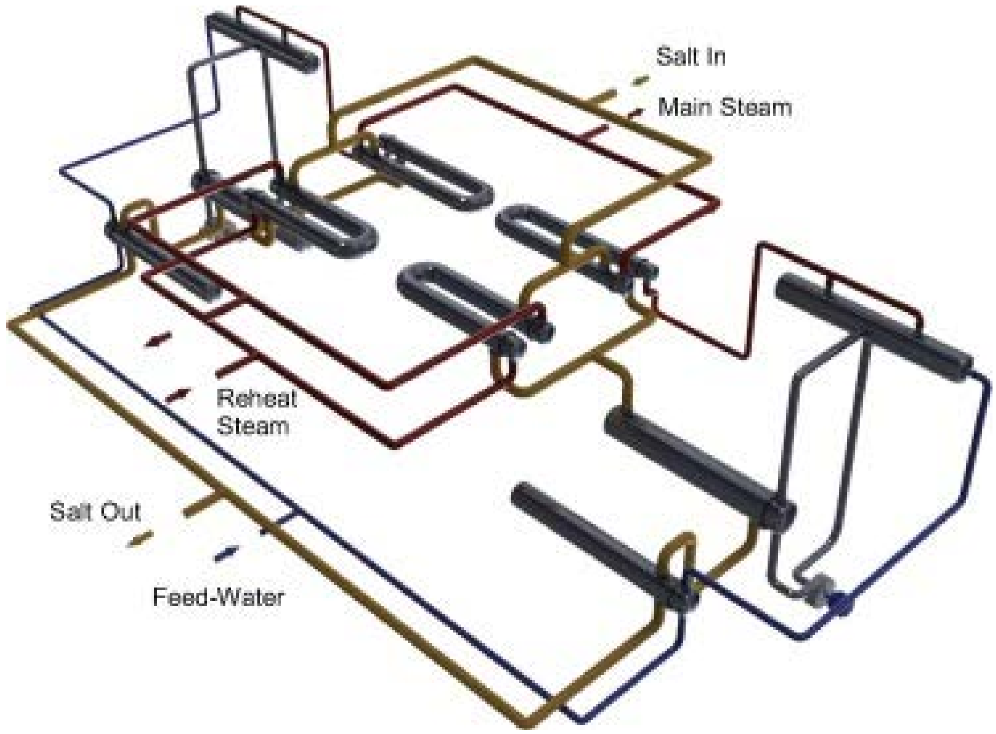

Figure 6-6. Steam-generator arrangement with two 50% trains
Source: Google Images

6.2 Molten-Salt Tower Project

6.2.1 Increase in Commercial Plant Scale

Despite being very attractive from an economic point of view, there are significant technical risks in increasing the size of a commercial plant.

Background

For equipment suppliers, there is technical risk associated with scale-up of a central receiver project from a demonstration plant size (10 MW_e) to the final commercial size (100 MW_e or more). For example, equipment that works well on a small scale may not work well on a large scale, especially if significant design changes were made when scaling to the commercial plant size.

Best Practices

- Increase plant sizes in steps of an approximate factor of 3 to 4, based on receiver thermal rating. For example, if the receiver in a demonstration plant is 50 MW_t, then the receiver rating in the second pre-commercial plant should be 150–200 MW_t, and the rating in the commercial plant would be 450–600 MW_t. The factor of 3 was developed by a consortium of U.S. utilities[27] to minimize scale-up risk to commercial plant sizes.

[27] Solar Central Receiver Technology Advancement for Electric Utility Applications - Phase 11 C Topical Report, Report 007.25-92.2, Pacific Gas & Electric Company, San Ramon, CA, 1989.

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- To illustrate this, Solar Two (1999), the first salt tower demonstration project in the world, had a receiver rating of 42 MW_t. The first commercial salt tower project in the world, Gemasolar (2009), implemented a receiver rating of 120 MW_t, which is a nominal 3 times the receiver rating of Solar Two. After Gemasolar, the technology provider and the main EPC contractor selected a 660-MW_t receiver (5 times Gemasolar) for the second commercial salt tower plant, Noor Ouarzazate III (2015), also a reasonable scale-up.

- If a significant design change to a system component is made between steps (e.g., hot-tank foundation design, use of long-shafted pumps, a new type of heliostat), then separate component tests at scale should be performed to prove long-term reliability before integrating into a commercial project.

6.2.2 Knowing Local Labor Constraints

It is important to understand the local labor conditions prior to bidding a project. There are several examples of companies that did not fully understand the labor constraints at the sites where they were building projects. It is important to know whether union or non-union labor will be used and whether other labor laws must be dealt with. In the United States, for example, there are both federal government and state regulations that drive labor laws.

Many projects are in remote locations. It is necessary to understand whether it is possible to get skilled labor locally or whether it will need to be imported for the project. This becomes an issue for O&M, as well.

6.2.3 Designing Plant for 1% Operation

Plant designs often concentrate on design-point performance at the expense of process control during start-up and shut-down.

Background

The EPC contractor will, as a matter of course, develop a process design that is based on meeting design-point requirements, such as receiver output at noon on the equinox. However, a comparable effort is not always devoted to developing a design that can safely make the transition from hold to start-up, and from shut-down to hold. Specifically, equipment vendors normally specify various operating limits. For example, the heat exchangers in commercial-size steam generators have a minimum flow rate of about 15% of the design flow rate and an allowable rate of temperature change on the order of 10°C/min. During a transition from hold to start-up, the heat exchangers would, in principle, be forced to operate at flow rates below the minimum. Operating at low flow rates can result in nonuniform flow distributions that, in turn, can produce nonuniform temperature distributions. The latter situation can result in nonuniform stress distributions, which can compromise the low-cycle fatigue life of the equipment.

It is incumbent on the EPC contractor to develop a process design that satisfies the vendor limits. For example, one approach to satisfying the minimum flow limit is to establish a cold-salt flow rate of 15% during hold periods. Then, during start-up, hot salt is blended with cold salt, with the flow rate of hot salt selected to provide a rate of temperature change of 10°C/min. Because the flow of hot salt is in addition to the flow of cold salt, the minimum flow requirement is met throughout the transition. As important, the equipment can now safely operate at very low loads

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(i.e., 1% operation) for extended periods of time. This, in turn, precludes the need to accelerate transitions in an effort to minimize the time that the equipment is operating under potentially damaging conditions.

Best Practices

- It is important that the plant be designed to continuously operate safely at both the design condition and the 1% load condition. The design includes process control (valves and flow control), equipment design (heat-exchanger fabrication methods), and control-system protection (logic, warnings, and alarms).

- The plant must be designed to accommodate, as a minimum, daily thermal cycling within the allowable rates of temperature change specified by the equipment vendors. Ideally, the plant would be designed for something on the order of 3 cycles per day and to have the ability to accept some limited number of transients at conditions outside of the vendor limits. Specifically, the control system will not always be able to operate the equipment within the vendor limits. Sticking valves, inaccurate flow meters, and financial pressures on the operators will cause the limits to be exceeded at various times. Also, the prediction of low-cycle fatigue damage is not an exact science. Providing some assurance that the equipment will survive 30 years of cyclic operation warrants selecting a design criterion of 3 cycles per day.

6.2.4 Plant Performance

The performance of the early commercial projects has generally been below projections.

Background

Commercial-scale central receiver technology is relatively new, so there has been a technical risk in reaching the annual electricity goal for the early commercial plants. The risk is higher in central receiver projects than in parabolic trough projects due, in part, to the much larger number of trough projects in commercial service and the single-point failure potential of the receiver system. Annual energy estimates for central receiver projects have been unrealistic (optimistic) in some cases, both in terms of system performance and plant availability. Part of the problem lies with the general lack of commercial experience with new technologies; another part of the problem lies with aggressive marketing by project and technology developers.

Best Practices

- Project developers should focus a good share of their efforts on achieving realistic estimates of annual electricity production. In the first commercial plants, (1) unforeseen problems significantly reduced production, and (2) limited performance data were available on commercial plants to calibrate the performance models. Experience has shown that unavailability of plant hardware has a much larger impact on energy production than efficiency degradation, and it may be that availability is the most important parameter in energy production. Thus, more attention should be given to component and system reliability than component efficiency.

- Precise representations in performance models of the flux limitations of salt receivers have been a major source of deviation when predicting plant performance; i.e., some

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projects have overestimated expected performance. It is a good practice that the models accurately represent flux limitations, together with other receiver characteristics (start-up durations, shut-down durations, and transient periods), as similar as possible to actual conditions during plant operation.

- Transients need to be properly accounted for in the design of the system and performance model including start-ups, shut-downs, receiver performance during cloudy periods, and cooling of the turbine. Model time-steps should ideally be 1 to 2 minutes, although using 5- or 10-minute time steps will lead to almost the same annual results in a simulation. 15-minute or longer time steps are not recommended if accuracy in representation is required.

- As an example, field stowage due to high winds may last for 20 minutes, and this cannot be accurately represented with 15-minute time steps or using 15-minute average values of wind speed as an input to the model. Instead, for performance-test evaluation purposes, the model should be forced to stow the field when, in real life, the plant is doing so. The control logic that governs the stowage of the field during a high-wind event is more complex than what a model often considers in a simulation.

- The observation that reality is more complex than what the model can consider should be extrapolated to other events occurring during a plant simulation.

- An increase in the expected performance during the first 3 years of operation (e.g., 80% - 100% - 100%, or 85% - 95% - 100%) is a good practice to cover unexpected or infant mortalities at the beginning of commercial operation. The rate of increase will depend on a number of factors, such as experience of the technology provider and the EPC contractor, the experience of the operator, weather conditions (amount of cloud transients, probability of extreme temperatures or winds), and innovations in plant design (similarity to other plants in operation).

- Only a limited number of commercial central receiver projects are either in operation—Gemasolar, Crescent Dunes (operation currently suspended), Noor Ouarzazate III, two pilot plants in China, and two commercial plants in China—or in the final stages of construction (Cerro Dominador). In contrast, the number of parabolic trough projects in commercial operation is at least an order of magnitude greater. As such, the level of annual availability for central receiver projects has yet to reach the level of availability for trough projects. For the first generation of central receiver projects, the plant availability may be limited to values in the range of 90% to 92%. Contributing to the lower availability are potential single-point failures in a central receiver project (receiver, hot-salt tank) that are not present in a trough project. For example, the failure of a receiver in a trough project only results in the loss of that collector loop. However, as central receiver technology matures, plant-availability values should become fully comparable to trough project values.

- A conservative value for the average heliostat cleanliness is 95%. However, a cleanliness value of 97% is achievable with a sufficient number of washing vehicles and a comprehensive cleaning strategy.

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- Heliostat-field availability has been proven to be in the range of 99% during mature operation. Conceptually, the availability of a heliostat field should be higher than a trough field due to the lower complexity. Specifically, there is no fluid in the heliostat field, there are no ball joints or flex hoses, and there are no moving parts connected to fixed components.

- Actual direct normal radiation and weather data for the site should be used to calibrate satellite estimates (the most-used method for estimating long-term insolation at a plant site). Producing a TMY dataset without considering onsite data is not considered a good practice.

6.2.5 Project Audits

Complex projects require independent audits of the EPC contractor by the owner/final client.

Background

Central receiver plants are complex projects in which many technical details need to be implemented properly for the plant to be successful. The probability is high that a lack of oversight will lead to unforeseen technical problems.

Best Practice

- The project developer should employ a highly qualified, full-time technical advisor(s) to audit the design, construction, and commissioning of the plant. It can be noted that the CSP projects that have been most thoroughly monitored by the owner have been the most successful in terms of both cost and performance.

6.2.6 Equipment Suppliers

Separate suppliers for the heliostat field and the receiver may not result in the lowest cost to the project.

Background

In the interests of reducing the capital cost of the plant, a project developer may decide to choose separate suppliers for the heliostat field and the receiver. This arrangement creates a difficult interface issue when it comes to performance evaluation.

Best Practices

- The heliostat field and the receiver need to be designed, supplied, and guaranteed by one entity. Any expense saved by choosing separate suppliers will be lost (and likely more) to resolve interfaces and responsibilities between the parties. For example, if the receiver underperforms, the fault may not lie with the receiver; it may be due to heliostat slope and pointing errors that are greater than guaranteed values. Arguments will invariably occur between the parties, and these issues are very difficult to solve in a manner that benefits the project.

  Note that currently, there is no method capable of measuring the incident flux on the receiver with an accuracy of ± 1%; even an accuracy of ± 5% accuracy is quite difficult

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to achieve. Therefore, the allocation of responsibilities between the heliostat-field supplier and the receiver manufacturer is simply an illusion.

In addition to the flux-measurement problem, the division of responsibilities between the two vendors may be even more obscure when the control systems of the receiver and the heliostats are separated.

When analyzing system performance, separating the heliostat field and the receiver in a central receiver project could be compared to separating the mirrors and the absorber tubes in a trough project. No one has considered this approach because it makes no practical or contractual sense.

- The receiver vendor is motivated to select the smallest absorber possible in an effort to reduce the cost of the receiver. However, there is a risk that the receiver supplier will impose unrealistic goals on the cost and the performance of the heliostat field. This is particularly the case if the receiver supplier is responsible for the layout of the heliostat field, which has occurred in several projects.

  In general, this not a good engineering practice. All plant components must be defined in a way that minimizes the global figure of merit of the project—usually the levelized cost of electricity—and not the cost of particular subsystems.

- Following a similar theme, in some projects, the heliostat field could not simultaneously meet the guaranteed price and the guaranteed optical accuracy. In this contest, price becomes the dominant consideration, and the consequence is often receiver spillage losses that are much higher than expected. The problem is more pronounced in large projects, in which the furthest heliostat can be more than 1 km from the receiver. With additional plants, the relationship between price and accuracy will be better defined. Specifically, a floor on the heliostat price, consistent with a defined optical accuracy, will become known. Once this relationship is defined, the option for the separate supply of the heliostat field and the receiver should become more commercially practical.

6.2.7 Welds in Salt Piping

Improper welds in salt service are a source of leaks.

Background

Improper welding of molten-salt piping has led to pipe leaks and plant outages.

Best Practices

- Welds in molten-salt piping must be very high quality. To achieve this, the welds should be performed, if practical, using automated machines rather than by hand.
- All welds related to salt flow should also be accessible for X-ray examination.
- Piping and filler materials used should be 100% traceable and undergo 100% verification.

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- Special attention should be paid to the design and construction of the salt piping system in the tower (riser and downcomer) due to the difficult operating conditions of these lines, including temperature and flow transients, thermal fatigue, and high pressure losses.

6.2.8 Owner's Technical Specification

Central receiver technology has yet to reach commercial maturity. Until an industry consensus is reached on a commercial-plant design, the Owner's Technical Specification is one mechanism for retaining the intellectual property needed to reach a consensus design.

Background

Parabolic trough power plants have essentially reached commercial maturity. Specifically, an industry consensus has been reached on items such as operating temperatures, materials, pump-seal plans, equipment redundancy, and Rankine-cycle parameters. In contrast, central receiver technology is still in an advanced development phase. Questions remain on a wide range of topics, including the optimum heliostat reflector area, methods for calculating the creep/fatigue life of the receiver tubes, type of valve-stem seal, heat-trace design criteria, salt-tank foundation design criteria, and approach to post-weld heat treatment of stainless steel.

As a result, there is a significant difference between the degree of specialized knowledge required for companies involved in central receiver technology compared with those involved in trough technology. At this point in time, it is important to make sure projects select companies experienced in central receiver technology to construct projects. Selecting less-experienced companies to build central receiver projects can result in very unsuccessful outcomes. In many projects, price has been the main driver to make decisions, and this has been proven to be a poor choice in the long run. The complexities of central receiver technology have to be carefully considered until technical maturity is achieved.

Essentially all of the design and operating experience, both positive and negative, resides with a limited number of project owners and EPC contractors. However, so few plants have been built—or are planned to be built—that no one company has access to all of the available project experience. Further, the time between projects for a given owner or EPC contractor may be long enough that key personnel have moved to another company or retired. As such, there is currently no industry database that can support defensible estimates of the cost, schedule, and performance of the next project. Much of the knowledge is held by a few private companies. As a result, much of the key knowledge is proprietary information.

Best Practices

- A consensus on the industry database is some years away. In the interim, project owners can retain, and put to use, as much of a consensus design by assembling, and periodically revising, an OTS. Ideally, the technical specifications would be shared among the industry's participants. However, intellectual property and commercial considerations have generally precluded this option.

- The OTS would provide infinite detail on successful aspects of earlier projects. One of the principal purposes of the Specification would be to mandate—to returning or new

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EPC contractors—the plant design parameters that are required for a successful project. Included in the Specification would be a list of approved equipment suppliers. The goals would prevent the EPC contractor from (1) selecting a second-tier equipment supplier in the interests of seeking a low price, and (2) procuring the same equipment, such as pressure transmitters, from a range of suppliers.

6.3 Heliostat Technology

There is no industry consensus regarding the optimum size heliostat. As shown in Figure 6-1, both large (>100 m^2) and small (<20 m^2) heliostats have been deployed in commercial projects. Large heliostats have the potential for an improved economy of scale because they use fewer components per square meter. However, large heliostats are subjected to higher wind loads. Smaller heliostats can often use commodity drive units used by non-solar technologies. This can reduce costs relative to a large heliostat, which requires the use of unique and costly drives that can handle the higher wind loads. Small heliostats also have a smaller beam size, which improves receiver intercept; at the same time, they are more prone to soiling because of proximity to the ground. How to best estimate wind loads and how wind impacts cost and optical accuracy is also open to discussion. Historically, a rough estimate of heliostat wind loads was calculated by the mathematical methods described in reports by Peterka. More recently, industry has been able to place small heliostats in wind tunnels to actually measure the loads. For large heliostats, sophisticated proprietary mathematical methods are now used.

6.4 Heliostat System

The heliostat system consists of thousands of two-axis-tracking mirror assemblies that reflect the sun's light to specific locations (aimpoints) on the receiver. Beams are spread along the vertical axis of the receiver and across the width of the receiver to make the flux more uniform and to keep the peak flux within design limits. Heliostats closest to the tower have the smallest beam size and can be aimed above/below the receiver equator without spilling excess power. Heliostats far from the tower have much larger beam sizes and are aimed at the center of the receiver to minimize spillage. The optimum aiming strategy is one that keeps the spillage to a minimum and simultaneously maintains incident flux levels consistent with a 30-year fatigue life.

Maintaining a high reliability for thousands of heliostats can also prove challenging. Nonetheless, commercial power towers have succeeded in achieving high heliostat availability, albeit after solving some initial start-up issues. The best practices adopted to solve start-up and other heliostat issues are discussed in the paragraphs that follow.

6.4.1 Aimpoint Verification

A commercial method for determining the incident flux on the receiver has yet to be developed. As a substitute, the incident flux is calculated using a measured distribution of the reflected image from each heliostat, a heliostat pointing-error correction, and an assigned heliostat aimpoint on the receiver surface.

Background

High incident fluxes can lead to tube-overheating failures and/or a significant reduction in receiver lifetime. To ensure that each heliostat is truly hitting its prescribed aimpoint, two checks are performed:

1. Every few weeks, the aiming accuracy of each heliostat is checked by aiming at the center of the beam-characterization system target below the receiver or, alternatively, aiming at a look-back camera located in the air space above the receiver. If the beam is not in the center, then aiming errors are corrected by inserting offset values into the tracking algorithm.

2. Encoder data (i.e., the heliostat's physical position during tracking) are examined during operation as a quality check.

Best Practices

- If a problem is detected, the heliostat is declared "lost" and is taken out of service. These two checks help to provide the confidence needed to protect the receiver from damage.

- Notwithstanding the above, if a heliostat field has been properly calibrated, adjusted, and fine-tuned during plant commissioning, then its tracking accuracy should remain accurate during its entire life under normal conditions, as has been experienced in several plants.

6.4.2 Heliostat Position Encoder

Heliostat position encoders have not been as reliable as anticipated.

Background

Heliostats use encoders to determine their physical position while tracking. In one commercial heliostat design, two encoders are used as follows:

1. One encoder counts the revolutions of the azimuth/elevation motors that move the azimuth/elevation gear drives.

2. A second encoder monitors position strips on the torque tube for the elevation drive. As the heliostat moves, an optical device reads the strips to determine absolute location. This method has the benefit of measuring the actual position of the tracking axes, without inaccuracies in measurement due to backlash or wind-induced vibrations.

As a quality check, the results of these two methods are continually compared. If they disagree, the heliostat is declared "lost" and taken out of service. This quality check appears to be most important for smaller receivers with higher peak fluxes to prevent overflux and tube damage. Care must be taken when installing the optical device that reads the azimuth/elevation position strips. If the gap (head clearance) between the optical reader and the position strip is not within specification, then errors can occur that lead to the heliostat being declared "lost" and removed from service. Head clearance can also be in error if the strip is installed on an out-of-round torque tube.

Position encoder errors also occur due to dust and grease accumulation on the optical devices.

Best Practice

- For proper encoder operation, the head clearance must be checked and adjusted periodically, and the optical devices must be kept clean.

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6.4.3 Heliostat Availability

Background

To maintain a high availability of the heliostat field, the operability of each heliostat must be verified on a daily basis.

Best Practice

- By pinging each heliostat from the control room during the overnight shut-down, "lost" heliostats, as well as those with communication problems, can be identified and rectified, if possible, before plant start-up in the morning.

6.4.4 Electrical Design

Background

Problems with electrical distribution in the heliostat field can result in heliostats being declared "lost" or becoming inoperative. There are several electrical issues that can lead to this, including poor grounding, electric harmonics, low voltage levels, high voltage levels, and lightning strikes.

Best Practices

- Each heliostat must be properly grounded. The heliostat control unit must have good contact with the frame, and the grounding rods must be clean of paint or other coatings that could interfere with a good contact with the soil. The ohmic resistance of each grounding rod must comply with the National Electric Code requirements.

- Electric and magnetic noise and harmonics in the field electric circuitry can lead to problems. The source of the problems can include inadequate grounding and noise transferred between cables in the same conduit. If these are suspected, an electrical transient analysis, coupled with field measurements, should be performed. The tests should include an analysis of heliostat control-unit harmonics. If detected, active electric/magnetic noise filters should be installed at the input to the heliostat control unit.

- If voltage levels at components in the heliostat field approach electronics threshold levels (e.g., transistor turn-on voltage), then unexpected behaviors can occur. Placing too many components in series (daisy chaining) can cause voltages to drop. Voltage levels must be maintained above threshold levels by limiting the number of electrical components in series.

- Field tests of multiple prototype heliostats installed at a test facility can expose problems with noise, harmonics, and threshold voltages prior to commercial service.

- Lightning more often hits the heliostat field than the power tower. At one plant, lightning strikes created electrical pulses that led to the outage of several thousand heliostats on more than one occasion. This led to the development of a proprietary method of isolating the effects of lightning strikes; today, only a relatively few heliostats are affected when the field is hit.

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6.4.5 Heliostat Hardware

Systemic failures of heliostat components can have a significant effect on collector-system availability.

Background

A heliostat comprises many subcomponents that usually come from different suppliers and different production runs. If one of the subcomponents contains a design flaw or develops a long-term reliability problem, then it can have a major impact on the availability of the entire heliostat field. Further, the systemic problem can take months or years to unfold, and identifying the culprit can be challenging.

Best Practices

- To aid future investigations of reliability issues, a database of the heliostat subcomponents should be compiled that contains information on the equipment supplier and manufacturing date. The database should be constructed during heliostat-field installation.

- Heliostats must be qualified to be reliable when exposed to expected environmental conditions. Special attention should be given to gear drives and motors. These components should be tested in environmental chambers under the worst set of expected conditions. For example, some ball-screw elevation drives have been found to be susceptible to water intrusion and freezing damage.

6.4.6 Prototype Heliostats

Background

In one project, due to commercial considerations between the project owner and the EPC contractor, a switch from one heliostat supplier to another occurred late in the project development phase. The selected heliostat had limited development time, particularly in the areas of site assembly, installation, and optical characterization. As a result, heliostat slope errors exceeded warranted values, and field corrections to module canting proved problematic.

Best Practices

- The optical, assembly, and installation characteristics of a prototype heliostat must be fully verified prior to commercial acceptance.

- The number of prototypes must be large enough to demonstrate an acceptable fabrication process and repeatable optical characteristics. The number of prototypes will depend on the type, size, complexity of the heliostat, and previous experience with similar designs.

6.4.7 Heliostat Optics and Cleanliness

The optical efficiency of a heliostat field can be more difficult to maintain than originally expected.

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Background

Mirror washing significantly improves plant performance and has been shown to be among the most cost-effective of O&M expenses. Wash trucks that use spray, deluge, and brush techniques are typically used to maintain 95% field-average cleanliness. Site soil conditions can sometimes make it difficult for wash trucks to gain access to portions of the heliostat field.

As mentioned previously, the beam-characterization system is used to evaluate heliostat tracking accuracy. However, the system also examines the shape of the beam to see if there are mirror-canting or focusing problems. The system cameras develop a beam image in the software, and an algorithm is used to determine the power centroid. The centroid calculation can be contaminated by receiver spillage if the system target is too close to the receiver or the spillage losses are higher than expected.

Heliostat facets are typically canted to design specification during assembly of the full heliostat reflector in an onsite shop. Upon completion, the reflector assembly is moved to the field and mounted to the pedestal. Canting errors can occur in the shop as well as during transit to the pedestal. The latter can occur during reflector vibration when traveling over rough roads. Experience has shown that 10% or more of heliostats in the field may need to be recanted after installation to obtain optimum performance. For many commercial projects, recanting a heliostat, once in service, has proven problematic.

Heliostat facets are also focused to design specifications by creating a slight concave curvature in the factory. It has been discovered that this curvature and focus can be changed if the back of the facet is heated by the beam from the heliostat behind it. The defocusing is due to differences in the coefficients of thermal expansion for the glass mirror and the metal structure supporting the glass mirror. Some level of beam blocking is an expected part of an optimized heliostat-field layout and typically reduces receiver energy collection by a few percent. Evidence now suggests that this few percent could be doubled due to the combined blocking/defocus effect. To the extent that facet defocusing can occur, the effect must be included in the annual performance calculation of the collector system.

Another optical energy loss is the occasional delay in plant start-up due to frost on the heliostat mirrors. First discovered at the Solar One project, frost can occur in winter when the mirror surface is exposed to atmospheric humidity and radiation to the night sky. At Solar One, the heliostats were defrosted by aiming the heliostat at the rising sun. However, the process was rather lengthy, often delaying start-up by an hour or more. Today's commercial power towers have discovered a method to avoid the formation of frost. During winter nights, heliostats are stowed vertically rather than horizontally. This greatly reduces the radiation view angle to the night sky and keeps the mirror temperatures above the dew point. This approach was first proposed by plant operators who observed the frost on their cars: frost always occurred on the windshield and roof, but not on the side of the car.

Best Practices

- Before purchasing a wash truck, a prototype should be exercised, in a comprehensive manner, to ensure that the heliostats can be cleaned to the required reflectivity and that the cleaning mechanism operates reliably. The prototype should be driven under expected wet soil conditions to ensure that the truck can always maneuver in the field. Further, a

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complete set of spare parts should be purchased, and routine service of the wash mechanism must be demonstrated.

- To develop an optimum washing strategy, a detailed knowledge of the field reflectivity is required. The areas of the field that require the most cleaning—especially those areas that have the largest effect on plant performance—should be defined using a statistically defensible random-sampling method. Unlike trough projects, in which each trough has about the same influence on plant performance, not all heliostats in a central receiver project are created equal. This is because heliostats closest to the tower have the smallest image sizes and the lowest spillage losses. When developing an optimum washing strategy, heliostats closest to the tower should be given the highest priority.

- Beam-characterization targets should be located such that spillage losses from the receiver do not adversely influence the calculation of the heliostat beam centroid and reflected power.

- Once a heliostat is installed, recanting the mirror modules is a difficult task. The national energy laboratories, including Sandia National Laboratories, are developing experimental methods for recanting in the field. Collaboration with the national laboratories could prove useful for both new and existing projects.

- Heating of the back of the mirror modules is inevitable due to blocking effects. Ideally, the modules would be designed to maintain at least a convex front surface throughout the day. Potential approaches include a shorter focal distance, a reflective back surface, or the use of back insulation. Blocking occurs on a limited number of the mirror modules, so only those facets exposed to heating would need to use a specialized facet.

- Some level of blocking will always occur in a heliostat field, so it is important to include this effect in the plant-performance simulation. Furthermore, a proper plant design will consider the influence of facet blocking on field performance, and it will avoid the use of heliostat locations that are economically inefficient due to low optical performance.

- To minimize frost accumulation, a vertical stow can be used during winter nights when wind conditions do not require horizontal stow.

6.4.8 Heliostat-Drive Failures

Background

Occasional failure of heliostat elevation drives has led to rapid falling of the mirror assemblies. Although nobody has been hurt to date, injury would be nearly certain if someone were standing beneath the heliostat when these failures occurred.

Best Practices

- As an interim solution, exclusion zones beneath the heliostats have been established when personnel are performing maintenance. The boundaries of the exclusion zone are based on a detailed evaluation of the direction that the mirror assembly would fall following a failure of the elevation drive.

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- A comprehensive solution involves modifications to the elevation drives to ensure that the jack screw does not come free of the support structure.

6.4.9 Collector-System Control Logic

Background

Permanent damage to about a dozen tubes occurred in one plant when the flux from several hundred heliostats was placed on the receiver with no salt flow. The damage occurred due to a logic sequence in which the heliostat field was commanded to "Track" after a trip in the electric power-supply circuits had been cleared.

Due to numerous alarms in the control room, the operator did not notice that the receiver was illuminated for a period of 6 minutes.

Best Practices

- During a HAZOP analysis, the control logic should be reviewed for instances in which the normal permissives and interlocks can be bypassed. In this instance, a "Track" command should be prohibited unless salt flow is confirmed in the receiver.

- Control logic, as a key feature to assure plant performance and availability, must be thoroughly checked and commissioned before it is installed in the plant.

6.4.10 Control-System Software and Ownership

Background

At one project, one contractor was responsible for the heliostats and the heliostat controllers in the collector field, and another contractor was responsible for the heliostat-aiming software as part of the receiver scope of supply. Commercial conflicts arose during the plant-performance verification period. Specifically, the heliostat-aiming software was considered proprietary to the receiver supplier, and the receiver supplier did not want to release the source code to the plant operating contractor.

Best Practices

- The heliostat control software should have gone into escrow at a defined point in the commissioning period.

- A technical services agreement between the software developer and the operating contractor should be set in place to provide technical support for a defined period and at a defined price. The services agreement must define those categories in which changes to the software—such as absorber aimpoints—transfers care, custody, and control of the receiver from the software developer to the operating contractor.

- This issue is an additional indication of the range of problems that can occur when separating the heliostat-field supply from the receiver supply. One example is the speed of communication between the DCS and the heliostat field. The speed must be high enough to protect the receiver in the event of an emergency defocus.

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- The software use-cases should be reviewed by the all subsystem owners (e.g., heliostat field, receiver, thermal storage, power generation) to ensure proper functionality and trip behavior.

6.4.11 Heliostat-Foundation Cost Reduction

Background

Most commercial projects have used pedestal-style heliostats in which the mirror assembly is supported by a single pedestal inserted into the ground. In a typical installation, concrete is poured around the pedestal to form a secure ground attachment. However, one project found that the existing soil condition allowed a secure attachment without the use of concrete. Instead, a hole slightly smaller than the pedestal diameter was drilled, followed by hammering the pedestal into the hole. This significantly reduced installation cost due to increased installation speed and elimination of expensive concrete.

Best Practices

- Not all soil conditions will allow pedestal installation without concrete. If the soil is too sandy, then concrete must be used.

- If installation without concrete is employed, there is a chance for the pedestal to rotate within the hole and degrade aiming accuracy. This occurred on the edges of the heliostat field that was exposed to wind and not on interior heliostats. To fix the problem, a cross-bracing was installed underground to prevent rotation.

6.4.12 Heliostat Power and Controls Cost Reduction

Background

The heliostats in most commercial projects are powered and controlled via underground cables. This adds significant cost, reliability, and lightning-strike issues (e.g., see previous Electrical Design section). Research has been ongoing for more than a decade to eliminate the underground cables by using radios to send control signals and using a small PV panel and battery to power the heliostat. Until recently, this “autonomous” heliostat design was cost-prohibitive relative to the underground-cabling approach.

Best Practice

- One recent commercial plant successfully implemented the autonomous heliostat approach. The keys to success were the recent drop in PV panel, battery, and radio-transceiver costs, as well as a significant increase in battery lifetime (10 years). In addition, power consumption was reduced by using supercapacitors that are continuously charged and fired only when motion is required.

6.5 Receiver System

The prototype molten-salt receiver at Solar Two in the late 1990s contains many design features found in today’s much larger commercial-scale receivers. Molten salt flows through about a dozen panels of alloy tubes arranged in cylindrical configuration on top of the tower. As the incident solar flux from the heliostat field changes throughout the day, salt flow within two separate flow paths is regulated to maintain an outlet temperature of 565°C. Salt exiting the receiver is delivered to the hot tank at ground level via the downcomer piping.

The Solar Two receiver was plagued by salt-freezing events that resulted in many plant outages. During start-up, it was difficult to heat tube panels at the edges of the ovens due to design flaws at this location. Much was documented on how the flaws resulted in salt freezing within the tubes and how to change the design to avoid the problem in future plants. Today's commercial receivers have learned from Solar Two's experience and are no longer plagued by routine salt freezing during start-up. However, salt freezing within commercial receivers has occurred a few times in certain plants, but not in others—at times, due to problems with the drain valves or defects in the drain-line insulation, which caused salt to freeze in the drain lines. Thawing of the frozen panels was performed in a methodical manner, using a combination of energy from the ovens and energy from the heliostat field. The goal was to heat the panels from the bottom to the top and to always provide a path for salt, as it melts, to leave the panels. Generally unknown is to what extent the tubes may have been subjected to plastic deformation during the thaw process.

Some new receiver-system issues have surfaced in today's commercial plants and have resulted in plant outages. In the sections that follow, we describe the receiver-system problems that have had the greatest impact on plant availability and the best practices to avoid their reoccurrence in the future. An accurate receiver control system, coupled with an advanced flux-measuring system, is essential for proper system operation.

6.5.1 Downcomer and Outlet Vessel

The static head in the receiver downcomer needs to be dissipated. The standard approach has been to use a receiver outlet vessel in combination with a throttle valve at the bottom of the downcomer. This approach has been demonstrated at Solar Two and is being used in several commercial plants. However, this solution is expensive, the outlet vessel is subjected to rapid temperature gradients, and the valve(s) at the bottom of the downcomer is a potential reliability concern.

Background

The Solar Two receiver used an outlet vessel, located above the receiver panels, at the exit of the two flow circuits. The vessel provided a level control signal to the throttle valves located at the base of the downcomer. The purpose of the control valves was to (1) maintain the downcomer in a completely flooded condition, and (2) dissipate the static head in the downcomer. At least three projects have used the approach demonstrated at Solar Two. Nonetheless, the outlet vessel can be subjected to rates of temperature change as high as 6°C/s during certain transient conditions, such as a receiver trip or loss of level control signal. Further, the transient conditions can establish vertical temperature gradients within the vessel of 200°C–250°C. The vessel must be designed to accommodate the transient conditions over the 30-year life of the project. In addition, throttle valves are problematic in salt service. The reliability of the throttle valves at the bottom of the downcomer becomes a concern.

Simplifications to the basic Solar Two system design can reduce cost. For example, one approach tested at Sandia National Laboratories, used a series of orifice plates in a vertical pipe. The distance between plates was about 3 m, and water was used to simulate salt. At high flow rates, a water column about 2.8 m high was established above each plate. At low flow rates, the

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water column decreased to about 0.3 m. The system (called "cascade flow") was quite noisy, and some pipe vibrations were noted; but the pressure of the water leaving the pipe was nominally atmospheric. The cascade flow approach eliminates the need for the receiver outlet vessel, the control/throttle valves at the bottom of the downcomer, and the need for an overflow drain line from the receiver.

Because the results at Sandia were promising, a commercial project adopted the orifice approach. However, significant vibrations in the downcomer were noted during plant commissioning. The problem was traced to pipe supports that were not designed for the dynamic loads that would be experienced with cascade flow. Rather than reinforce the pipe supports, conventional control valves were installed at the base of the downcomer. The control logic was then changed such that the downcomer always remained flooded. Because the receiver did not have an outlet vessel to provide a level control signal to the downcomer valves, level control in the downcomer was based on signals from new pressure transmitters installed upstream of the valves. Although this plant in normal operation used the throttle valves to control the level in the downcomer, on occasions when the receiver is tripped and the throttle valves are opened full to drain the receiver, then the accelerates to the point that cascade flow is momentarily established. It was generally believed that a more comprehensive analysis of an orifice system, including calculations of the dynamic loads on the pipe supports and anchors, would result in a successful approach for a commercial project.

Best Practices

- If a vessel design can be developed that safely tolerates the expected thermal transients, then the downcomer can always operate in a flooded condition. As such, the fluid velocities will always be in the range of 1 to 3 m/s, depending on the receiver flow rate, and the hydrodynamics loads on the downcomer will always be modest and predictable.

- At the commercial project that used orifices plates, the design and operation of the downcomer were fundamentally different than the flow regimes demonstrated in the Sandia experiments. The problems seen in the commercial plant are not necessarily an indication that the orifice-plate concept is an unsuitable approach for commercial use. Nonetheless, additional tests are needed—at both the prototype scale and something close to commercial scale—to develop the design criteria needed for a commercial project.

6.5.2 Tube Replacement

Background

The receiver component consists of several hundred tubes that have a 30-year design life. However, accidents and unforeseen events can occur, so it is prudent to assume that tube replacements will occasionally be required.

It is a complex and lengthy process to remove and replace a panel. It can be noted that there are little data available on the time required to replace a panel. As a point of reference, the original W2 panel on the Solar Two receiver was replaced with an advanced panel. The time required to remove the original panel was 3 days. The time was strongly influenced by wind conditions; the operation could be done only on a nearly calm day. Presumably, the time required to install the replacement panel and perform the required examination of the welds would be on the order of 3

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to 4 days. Thus, for the relatively small panels at the Solar Two project, the outage period required to replace a panel was 1 week. For the larger panels in a commercial receiver, the outage period is estimated to be 1 to 2 weeks.

One commercial vendor designs the receiver for replacement of complete panels, and a spare panel is kept at each site. However, the reliability of the panels in two commercial projects has been excellent to date, and there has been no need to remove and replace a panel.

An alternate approach to the replacement of a full panel is to design the panel for the replacement of individual tubes. At one commercial project, a total of 20 tubes were replaced in a 3-day period.

Best Practices

- Replacement of individual tubes has been demonstrated at a commercial project. The panel structure, insulation, instrumentation, and tube clips were designed with this repair approach in mind.

- The portions of the tubes that were replaced were in the absorber area, i.e., the tubes were not cut inside the oven enclosure. This necessarily places a tube weld in the flux zone. It is very difficult to perform a post-weld heat treatment on the repaired tube. As a consequence, the material properties at the weld are inferior to the material properties of the original tube; so, the lengths of the replacement sections were selected such that the welds are located in the low-flux regions of the absorber.

- To ensure weld consistency, the welds were performed with a machine orbital welder, and they met the requirements of ASME B31.1, Power Piping.

- The selective surface coating (Pyromark®) was applied to the weld zone. However, the optical properties of the coating at the welds are likely to be inferior to the optical properties on balance of the absorber due to the difficulties of curing the coating in the field.

6.5.3 Receiver-Pump Head and Flow

The expected margins in receiver pumps have not always been observed.

Background

In a commercial project, the receiver pumps produce high heads (>370 m) and require large motors (>1 MW_e). As such, providing generous margins on the head and the flow is an expensive undertaking.

The required head is a function of the friction factor in the riser piping and in the receiver tubes. The friction factor, in turn, is a function of the absolute roughness and the Reynolds number. The latter, in turn, is a function of the viscosity. There are some uncertainties in the roughness and the viscosity values. The roughness values are influenced by the corrosion rate of carbon steel in the riser and the corrosion rate of Alloy 230 in the tubes. Both rates are functions of time-at-temperature of the metals. The viscosity calculation is often based on equations developed at Sandia National Laboratories in the 1970s.

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Best Practice

- In the absence of additional data on tube roughness and viscosity, some level of conservatism is warranted in calculating the design receiver-pump head and flow rates.

6.5.4 Heat-Trace Transformer

Background

Depending on the contractual boundaries, the heat-trace circuits within the receiver scope of supply may be provided by the receiver vendor. However, the transformers supplying electric power to the receiver heat trace may fall under the scope of the supply of the EPC contractor. Depending on the schedule for the final design of the receiver and the schedule for the purchase of the electric equipment, the capacity of the transformer to supply the receiver may be less than typical commercial practice.

Best Practice

- Careful coordination must be maintained between the equipment vendors and the EPC contractor to ensure that equipment supplied by the latter meets the needs of the former.

6.5.5 Panel Flux Monitoring

For commercial projects, flux-monitoring equipment is in various stages of development.

Background

Solar input power to the receiver can rapidly change when clouds pass over the heliostat field. Salt flow rates must rapidly change to protect the receiver from overheating and to maintain the 565°C outlet temperature. Automatic flow control was primarily accomplished at Solar Two by using a feed-forward signal derived from several photometers surrounding the receiver that gauged the relative brightness of the glint reflected from the receiver surface. If located near the receiver, the photometers (a PV cell within a collimator) must be protected from the heliostat beams. A protected location near the receiver was found at Solar Two at the top of the targets for the beam-characterization system.

In contrast, at some commercial projects, the beam-characterization system targets are often located close to, and in some cases on, the tower to reduce costs. As a consequence, the photometers can overheat, particularly if the receiver spillage losses are higher than expected. In the absence of a feed-forward signal, the receiver control logic switches to manual control of the flow rate. To protect the receiver from transient conditions that might lead to overheating, the setpoint outlet temperature is reduced by the operators to values in the range of 530°C–550°C. The consequence is reduction in the temperature of the hot tank and a corresponding reduction in the efficiency of the Rankine cycle.

At two commercial projects, absorber fluxes are measured using flux cameras located in the heliostat field. The camera data are converted to receiver surface temperature using a set of control algorithms.

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Best Practices

- A trend in plant design is to use the tower as the target for the beam-characterization system. If so, the largest horizontal structure below the receiver is often the maintenance deck, and the dimensions of the deck may not be sufficient to (1) locate the photometers far enough from the panels to have an acceptable view angle, and (2) prevent the photometers from operating at high temperatures. To compensate, commercial photometers must be selected that are suitable for high-temperature service.

- As described above, photometers located in the heliostat field view the receiver panels through a telescope, and algorithms convert the reflected flux values into tube surface temperatures.

6.5.6 Receiver Vent Line

The receiver vent line is necessarily a complex and expensive item, but its importance is often underestimated.

Background

Whether the receiver uses an outlet vessel or a downcomer with orifice plates, a vent line is needed to connect the outlet of the receiver with the hot-salt tank. The purposes of the vent line are two-fold:

- Accept flow from the receiver in the event that the downcomer floods above the high-high level.

- Accept flow from the pressure-relief valve on the receiver inlet vessel.

The flow rate of salt in the vent line will depend on the anticipated failure modes, and it will depend on the head-flow characteristics of the receiver pumps during and following the failure. Nonetheless, the flow rate in the vent line can fall in the range of 50%–100% of the design flow rate for the pumps.

Best Practice

- The vent line may, or may not, have orifice plates to dissipate some portion of the static head. However, momentum forces at the elbows, particularly during unsteady flow conditions, can be at least an order-of-magnitude greater than the normal momentum forces in the downcomer. The pipe stress analysis must account for higher-than-typical forces in the supports and anchors.

6.5.7 Receiver and Heliostat-Field Optimization

An industry consensus has yet to be reached on the design criteria for the receiver absorber area.

Background

The design of the receiver, in combination with the layout of the heliostat field, attempts to reconcile the following competing effects: absorber area, tube low-cycle fatigue life, receiver efficiency, and spillage losses.

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Two important parameters in the optimization are the slope error and the pointing error of the heliostat. In many commercial projects, the errors are larger than those warranted by the heliostat supplier. The consequences are either spillage losses greater than expected or a low-cycle fatigue life shorter than expected. The latter can occur if the heliostat aimpoints are moved toward the center of the absorber in an effort to reduce the spillage losses. The receiver is a source of a single-point failure, so any reduction in the life of the receiver can have a large detrimental effect on the plant availability.

Note that receiver-tube failures due to low-cycle fatigue have yet to occur at the current commercial projects using salt receivers.

Best Practices

- Ideally, the heliostats in future projects will meet the warranted optical requirements. Nonetheless, some form of insurance is likely warranted. The insurance can take the form of an absorber area that is larger than the theoretical optimum. With the larger area, some loss in receiver efficiency will occur. However, the theoretical loss may be more than offset by an actual increase in the receiver output due a reduction in the spillage losses.

- There are little data on the expected fatigue life of a tube under the combination of strains and hold times seen in a commercial receiver. Until such data become available from plants that have been in operation for at least a decade, it may be prudent to add some level of conservatism to the design flux levels.

6.5.8 Tube Freezing and Recovery

Commercial methods must be developed to safely recover from salt freezing in a panel.

Background

At the Solar Two project, salt occasionally froze in the panels during filling. The problem was detected by an infrared camera observing the absorber. The frozen tube showed much higher temperatures than the tubes in which salt was flowing. The problem occurred almost exclusively on the windward side of the receiver and in the tubes at the edges of the panels. Several theories were proposed as the mechanism, but a definitive explanation was never developed.

At the Solar Two project, salt also froze in an entire panel on the first day of operation. The problem was traced to the incorrect location of a heat-trace control thermocouple in the panel drain line, which allowed the drain line to freeze.

At one commercial project, salt also froze in an entire panel. A small gap (~1 in.) in the pipe insulation above a drain valve allowed salt to freeze at this location during receiver operation. When a drain was initiated at the end of the day, the drain valve opened, but the panel remained flooded.

Best Practices

- In the phase change from solid to liquid, nitrate salt expands about 4%. If constrained, the volume expansion will cause the tube to yield.

- At Solar Two, the frozen tubes were heated first at the bottom using a limited number of heliostats. The goal was to reduce the potential for thawing in a constrained volume. As the thawing progressed, the aimpoints for the heliostats were moved up the panel.

- At the commercial project, temporary insulation was installed on the outside of the frozen panel at the bottom. The electric heaters in the oven below were set to a duty cycle of 100%, and conduction heat transfer was allowed to thaw as much of the bottom of the panel as possible. Once this process reached its limit, the temporary insulation was removed, and thawing continued using the process demonstrated at Solar Two. The position of the solid boundary could be determined by heating the panel and then observing the temperature decay with infrared cameras.

6.5.9 Infrared Camera

Infrared cameras are becoming a necessary element in the operation of the receiver.

Background

At the Solar Two project, a portable infrared camera was located in the heliostat field on the windward side of the receiver. The principal purpose of the camera was to look for signs of salt freezing in a tube during the fill process.

In most commercial plants, multiple infrared cameras are installed on a permanent basis. The cameras monitor outer tube temperatures to corroborate temperature measurements taken on the back of the tubes by an array of thermocouples and to corroborate calculations of incident-flux distributions. In the former case, the temperature measurements provided by the infrared cameras are particularly important because the reliability of the thermocouples attached to the back of the tubes has proven to be surprisingly low.

Best Practices

- Commercial projects will likely continue the use of infrared cameras for the purposes described above.

- It can be noted that one pixel on a commercial infrared camera represents about the width of one tube. As such, the cameras can only measure a weighted-average tube surface temperature, rather than a peak crown temperature.

- The algorithms to accurately calculate the receiver surface temperature based on the infrared cameras are as important as the cameras.

6.5.10 Construction Elevators

Background

In many projects, the receiver is fabricated by lifting components from grade and assembling the items at the top of the tower. This necessarily requires the construction workers to travel up and down the tower, often several times per day. To transport the crews, plus their associated tools and other bulk equipment, a temporary construction elevator is typically provided.

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In one project, the construction elevator was too small to move all of the personnel and equipment needed to maintain the receiver schedule in a 24-hour period. One estimate put the person-hours lost each day at several hundred while just waiting for the elevator.

Best Practice

- The rental expense for a large, high-quality construction elevator can be fully justified by the improvements offered in labor productivity.

6.5.11 Receiver Lift Elevator

Background

Assembling the receiver at the top of the tower, using items lifted from grade, is more labor-intensive than assembling the receiver at grade. Once assembled, the receiver can be lifted to the top of the tower using the tower as an elevator.

Two potential liabilities of this approach are as follows:

1. Fabricate the tower with an inside diameter large enough to accept the receiver. This is likely to result in a tower with a larger diameter, as well as a higher cost than a design that assembles the receiver at the top of the tower.

2. The large opening at the base of the tower required to accept the receiver must be closed, or reinforced, once the receiver is in place.

Best Practice

- A schedule and cost analysis should be undertaken early in the project to determine which approach is the least expensive: receiver assembly at grade or receiver assembly at the top of the tower.

6.6 Thermal Energy Storage System

Introduction

The molten-salt thermal storage system at Solar Two worked well. The 105-MWh_t system allowed the 10-MW_e turbine to operate at full load for 3 hours. The main components of the system included the following:

- Cold-salt tank, fabricated from carbon steel, operating at a nominal temperature of 290°C.

- Hot-salt tank, fabricated from Type 304 stainless steel, operating a nominal temperature of 565°C.

- Tank foundations using on an air-cooled concrete mat, Foamglas insulation, and a perimeter ring-wall of refractory bricks to accommodate the large vertical loads from the wall and the roof. A cross-section view of the foundation is shown in Figure 6-7.

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The tanks were designed to API 650, Welded Steel Tanks for Oil Storage. However, this code has an upper design temperature limit of 260°C. To accommodate inventory temperatures above 260°C, an application is made to the local Authorized Inspector to use the allowable material stresses from Section II of the ASME Code.

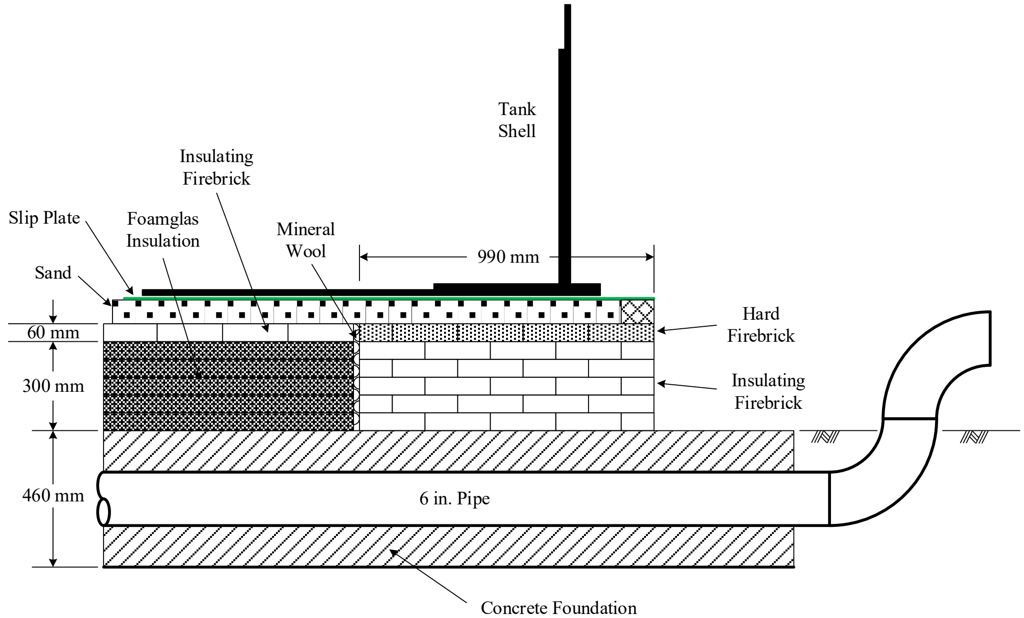

Figure 6-7. Cross-section of the hot-tank foundation at Solar Two

6.6.1 Tank and Foundation Designs for Commercial Projects

Failures of the hot-salt tanks have occurred at two commercial projects.

Background—Tank Design

Commercial projects in the United States, Spain, and Africa have continued to use the combination of API 650 and ASME Section II for the design of the tanks. Nonetheless, API 650 is intended for inventories operating at low to moderate temperatures and with temperature cycles on the order of days to months. In contrast, the storage tanks in solar projects operate at much higher temperatures and with temperature cycles on the order of minutes to hours.

Further, during transient solar conditions, both the cold tank and the hot tank can receive salt at temperatures as much as 100°C above or below the bulk inventory temperature. Salt is typically introduced into the tank by means of a circular distribution header near the bottom of the tank. The distribution header typically has a group of static mixers, distributed along the circumference, to promote mixing between the incoming flow and the main inventory. However, the diameters of commercial tanks are likely too large (~40 m) to ensure rapid and uniform mixing. As such, local temporary temperature gradients may develop within the inventory, and some fraction of the gradient may reach the floor and the wall. The magnitudes of the gradients at the floor and the wall are currently unknown. Nonetheless, nonuniform thermal expansion in the floor and the wall may lead to local transient stresses that are large enough to contribute to low-cycle fatigue damage.

In summary, thermal storage tanks in commercial projects are likely operating under conditions for which there are no design provisions in API 650.

Failures of hot-salt tanks have occurred in two central receiver projects. The failure mechanisms appear to be different, but may be a combination of one or more of the following effects:

- Local changes in the temperature of the inventory can lead to local changes in the wall and floor temperatures. These, in turn, can lead to local transient stresses produced by the local temperature gradients.
- Construction errors in installing the supports and anchors for the inlet distribution piping near the floor have been observed. The pipe was not supported in the manner intended, which transferred local bending moments to the floor.
- Construction errors in installing instruments intended to measure tank growth during heat-up. In one case, the instrument support structure impeded tank growth and caused tank damage.
- Shifting or unexpected movement of the foundation, leading to nonuniform support of the floor.
- Nonuniform coefficients of friction between the floor and the foundation along the radius, or around the circumference, of the tank.
- Rapid changes in the temperature of the bulk inventory due to manual operation of the hot-tank/cold-tank switching valves in an effort to reach daily performance targets.
- Receiver trips, which can produce rapid changes in the temperature of the bulk inventory. The rate of temperature change depends on the (1) speed of the hot-tank/cold-tank switching valves, and (2) tank level when the trip occurs.

Background—Foundation Design

The foundation design used at Solar Two worked well, but it was expensive. A subsequent commercial project simplified the foundation by replacing the Foamglas and the refractory materials with an insulating expanded clay, such as Utelite.

The bearing loads published by the vendor for expanded clay showed that the concentrated vertical load from the wall and roof could be accommodated with acceptable deflections of the clay. However, deflections at the perimeter of the tanks showed vertical displacements several times that expected. The large deflections mean that the thick circumferential plates, installed at the perimeter of the floor, have plastically deformed. The plastic deformations, in turn, mean the (1) low-cycle fatigue life of the thick wall-to-floor weld joint has been significantly reduced, and (2) perimeter plates curve down into the Utelite, which can restrict the radial movements of the tank.

On a separate topic, if the tank develops a leak, then the expanded clay is exposed to the salt. This has two negative consequences:

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- The thermal conductivity of liquid salt is about twice the thermal conductivity of expanded clay, and the thermal conductivity of solid salt is about 6 times the thermal conductivity of expanded clay. In the limit, enough salt can leak from the tank to saturate the expanded clay, at least down to the point where the salt freezes and forms a solid barrier. The increase in the composite thermal conductivity of the mixture of expanded clay and salt will result in a large increase in the heat losses from the tank.

- Salt is an oxidizing agent, and it converts the expanded clay from one oxide state to another oxide state. The reduction of the nitrate ion releases NO_x from the foundation in the form of a gas.

Once salt has leaked into the foundation, there is no mechanism to remove the salt other than removing the floor, elevating the tank, removing the foundation, replacing the foundation, replacing the floor, and then lowering the tank back into place.

Background—Thermal Losses

In some commercial projects, the heat losses from the tanks are higher than expected. The sources of the heat losses, in order of increasing uncertainty, include the following:

1. Conduction and convection heat loss through the wall and roof insulation. The thermal conductivities of the insulating materials are well known, and local degradation or defects in the insulation can be identified by infrared cameras.

2. Conduction and convection heat loss through the foundation. The thermal conductivities of the foundation insulation and the soil are well known. However, it is difficult to accurately determine the radial and vertical temperature gradients in the foundation, and the radial and vertical temperature gradients in the soil surrounding the foundation are generally unknown. Further, the cooling air for the foundation traverses the foundation, and this produces a three-dimensional temperature profile in the foundation. As such, the only method for determining the heat loss to the foundation is a finite-element model, and the accuracy of the model will be defined by the mesh dimensions.

3. Convection losses from the salt inventory. The source of the heat loss is the evaporation of water from the salt inventory. The source of the water is the steam-generator heat exchangers, either due to relaxation of the tube-to-tubesheet connections, or corrosion of the tubes. The evidence is largely anecdotal. However, steam-generator leakage is known to occur, and a leakage rate as low as 1.6 m^3/h (7 gpm) will result in a tank heat loss of 1 MW_t.

Best Practices

- Tank Design: In the absence of a design code dedicated to thermal storage tanks in solar applications, the combination of API 650 and ASME Section II can still be used. However, on a project basis, mandatory design appendices should be added to the procurement specification to include the following:

  - A computational fluid dynamics/finite-element analysis of the tank preheating method prior to filling with salt. The goal is to define a heated-air distribution method that maintains material stresses, throughout the tank, within the allowable values listed in Section II of the Code.

  - A computational fluid dynamics analysis of the salt flow into the tank, under both steady-state and transient conditions. The goal is to define a distribution-piping arrangement that maintains material stresses, throughout the tank, within the allowable values listed in Section II of the Code. The distribution piping may involve multiple distribution rings near the floor, or multiple rings at some elevation(s) above the floor. For example, at the Solar Two project, salt entered the hot-salt tank through an array of nozzles located within the roof dome. Alternately, some form of continuous forced recirculation in the tank may be necessary.

- Prior to tank preheating and filling, all of the structures—both inside and outside the tank—should be examined to ensure that nothing restricts the thermal expansion and contraction of the tank.

- All bolted connections inside the tank should be tack welded to ensure a 30-year life under cycling conditions.

- On some projects, it may be necessary to limit the tank dimensions to a maximum value, which, in turn, will require the use of more than one pair of hot and cold tanks. The maximum value will depend on the foundation materials, the coefficient of friction between the tank floor and the foundation, the effectiveness of the tank inlet piping in controlling radial and circumferential transient temperature gradients in the floor, and DCS limits on inlet flow rate and temperature as a function of tank level and inventory temperature.

- <u>Foundation Design:</u> The foundation design should incorporate the following features:

  - A rigid support at the tank perimeter should be provided to carry the concentrated load from the wall and roof down to the foundation slab.
  - If individual bricks are used to provide a rigid support, then the bricks should incorporate a tongue-and-groove arrangement to help lock the bricks into place.
  - A method should be developed to detect a leak in the floor. The goal is to minimize the fraction of the foundation insulation that would be contaminated by a continuing leak.
  - A continuous metal plate should be placed between the tank and the foundation to isolate the foundation from the effects of a leak.
  - A material under the tank should be used that provides a uniform coefficient of friction over the entire surface of the floor.
  - All other considerations being equal, foundation insulation materials that do not chemically react with the salt and that do not show large increases in thermal conductivity after exposure to the salt are preferred.

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- In addition, it may be necessary to program process limitations into the DCS. If some combination of tank level, salt flow rate into the tank, and temperature of salt entering the tank is calculated to produce a rate of temperature change greater than the allowable rate, then a trip command is issued to the solar field.

- Heat Losses: Heat losses from the tanks can be reduced by (1) repairing any degraded portions of the wall and roof insulation identified via walkdown with an infrared camera, (2) reducing the foundation cooling-air flow rate to the point where the soil temperature reaches, but does not exceed, the allowable value defined in the geotechnical study, and (3) repairing leaks in the steam generator.

- Reducing plant production losses due to hot-tank failure: If the hot tank develops a leak, then data collected during this Best Practices project indicates that a very long plant outage can be expected (i.e., many months). The tank must be drained and cooled, the root cause must be identified, and a fix must be engineered, perhaps resulting in a complete replacement of tank and foundation. Considering the relative immaturity of hot-tank technology, it is recommended that the plant design should allow for operation without the hot tank in the power-production loop. Other solar plants with storage, such as PV and CSP troughs, can operate without batteries or a hot tank, albeit at a lower annual output—but certainly much better than zero output, which currently occurs in today's commercial power towers. The risk associated with possible hot-tank failure was considered during the design of the Solar Two demonstration project. As an insurance policy, pipes were stubbed in with flanges that would allow a relatively quick addition of hot-tank bypass piping, if needed. The hot tank at Solar Two worked well, so operating in bypass mode was never implemented. Future commercial power towers should consider installing a bypass line and designing the control systems to allow operation directly from the receiver to the steam generator. A risk study should be performed to justify the additional expense associated with the bypass line.

6.6.2 Heat-Trace System

Heat-trace systems are often problematic and can suffer from inadequate heat output, poor control over local temperatures, and high cable-failure rates.

Background—Solar Two

The design criteria for the heat-trace system included the following elements:

- Mineral-insulated cables were procured from a commercial vendor.

- The preheat time for an empty pipe was 8 hours.

- Valves and adjacent pipe were heated as a common zone. The additional thermal mass of the valve body was accommodated by looping cables on the valve.

- Heat-trace cables were fabricated in the factory based on piping isometric drawings.

- Heat-trace control was provided by a standalone controller supplied by the heat-trace vendor. The controller was operated from a standalone console in the control room.

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A wide range of problems immediately appeared, as follows:

- The lengths of the cables were selected before the dimensions and weights of the valves were known. The cable supplier typically took a conservative approach as the estimated weights of the valves. This often led to cables that were too long to fit on the pipe and valve bodies. In many instances, the excess cable was simply looped on the pipe at the end of a zone. Power inputs in the looped sections could reach 2 to 4 times the power inputs in the non-looped sections, which led to severe overheating of the pipes at the ends of zones.

- The cable installers were provided no guidance as to how much cable was to be installed on each of the valve bodies. The results were steady-state and transient pipe temperatures that were markedly out of synchronization with the valve temperatures.

- The various plant operating states required different zones to be active or idle. However, the only method for converting a zone from active to idle, or the reverse, was to manually change the settings in the heat-trace console. This proved so cumbersome that zones were simply left in one state during all of the operating modes, leading to high power consumption, short cable lifetimes, and local pipe overheating and corrosion.

Efforts to essentially force the heat-trace system into operating patterns that met the needs of the plant failed, and about 80% of the original system was replaced with a new design criterion, new cables, and revised controls.

Background—Commercial Projects

The experience with heat tracing from the Solar Two project filtered through the industry; and to a large degree, commercial projects replicated the design of the revised heat-trace system from Solar Two. The principal change incorporated into commercial projects was for the pipe, valve bodies, and valve bonnets to be heat-traced as separate zones. Nonetheless, heat-trace systems are expensive, and commercial plants have often adopted the following approaches to minimize the cost:

- Using hold temperature, rather than preheat time, as a design criterion. In essence, a hold temperature is equivalent to an infinite preheat period.

- Assuming that the heat-trace vendor is accurate in stating that the lifetime of a cable is infinite. As a result, redundant cables are not needed, procured, or installed.

In practice, the above design approaches have led to a series of problems. First, an infinite preheat period means that there is no thermal power available from the cable above that necessary to maintain a hold temperature. When the insulation on a pipe inevitably degrades, the heat losses from the pipe increase and the hold temperature necessarily decays. A point can be reached where the hold temperature is equal to the salt freezing temperature. Once the pipe freezes, there is no mechanism for thawing the pipe other than repairing the insulation or cutting and removing the frozen section of pipe. This often produces a forced plant outage.

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Second, if the cable only operates in an air environment, and if the cable is not continuously supplied with electric power, then the life of the cable might be measured in decades. However, salt leakage past the stem seals on valves is more common than might be expected. The leakage rates are generally low; but over time, they will eventually saturate the insulation on the valve and the adjacent piping. Heat-trace cables, when operating with duty cycles at or near 100%, will develop temperatures above 700°C. Salt in contact with the cable will rapidly decompose into NOx as a gas and various oxides as a liquid. The oxides are extremely aggressive and can corrode the alloy sheath on the cable in a matter of days. Once the heating wires inside the cable are exposed to moisture in the air, the cable will soon fail. If redundant cables are not installed with the primary cables, then the zone will have no heat-trace capacity, which often leads to a forced plant outage.

Best Practices

- For a robust heat-trace system, the design should be based on the following criteria:
  - The preheat time for an empty pipe—from an initial temperature equal to the lowest ambient temperature to a final preheat temperature of 290°C—is 8 hours.
  - For valves larger than 2 in., the valve body is a separate heat-trace zone from the adjacent pipe.
  - The stem packing region and valve bonnet of each valve is a separate heat-trace zone.
  - Each pressure transmitter is a separate heat-trace zone.
  - In a piping zone, the number of installed redundant cables is 100% of the number of installed active cables.
  - In a piping zone, the number of installed thermocouples is between 3 and 6, depending on the length of the zone.
  - The unit power output of each cable is limited to 120 W/m to minimize the potential for corrosion due to salt exposure.
  - All of the heat-trace circuits are controlled through the DCS. This approach (1) allows the operators to monitor the status of the heat-trace circuits directly from the operator consoles rather than from a separate, remote heat-trace console, (2) allows the heat-trace circuit temperature setpoints to be adjusted based on the plant operating mode, and (3) provides a data historian of temperatures and power pulse widths to diagnose circuit performance and problems with temperature maintenance.
  - The selection of which zones are active is based on the plant operating mode. One of the goals of the zone definitions is to use the flow of salt to keep the zone at a safe operating temperature. This reduces the parasitic energy demand of the heat-trace system and improves the life of the heat-trace cables by reducing the duty cycles.
  - The definition, and the boundaries, of each zone are developed by the EPC contractor.

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- In some instances, a section of vertical pipe can operate flooded, empty, or partially flooded, depending on the operating mode. The zone boundaries, and the location of the thermocouples, must be selected such that uniform pipe temperatures are maintained in each of the operating modes.
- At least one commercial project using cables fabricated in the factory replicated a problem that also occurred at Solar Two, i.e., cable lengths did not always match as-built piping lengths, which resulted in too short or too long cables. Thus, it is recommended that heat-trace cables should be fabricated in the field based on as-installed equipment dimensions. This avoids two problems:
  - Cables that are too long. The extra length is often looped onto the pipe, which leads to high local heat inputs and overheating.
  - Cables that are too short. Gaps in the cable coverage lead to local zones that have metal temperatures below the freezing point of the salt.
- Installation drawings are prepared that show the exact location of each cable and each control thermocouple.
- A full complement of spare cables for pipes, valve bodies, valve bonnets, and instruments is maintained in the site warehouse.

- All cable installations are to be overseen by representatives of both the cable supplier and the EPC contractor, and not simply subcontracted to a group of local electricians. Further, all installations are to be photographed prior to installation of the thermal insulation. This will aid in troubleshooting when problems are discovered during commissioning and operation.

- Heat-trace maintenance and repair logs must be maintained to aid in system diagnoses and to ensure that a complete stock of spare equipment is always available in the site warehouse.

- Heat-trace control cabinets should be painted white and provided with forced-air cooling to ensure reliable operation of the equipment inside.

6.6.3 Support Requirements for Salt Pumps

The salt-pump vendor has strict guidelines on the support requirements for the pumps, but installation shortcuts have been observed in commercial plants.

Background

A mechanical seal suitable for use in salt has yet to be identified. As a result, all salt pumps are vertical designs. Shaft sealing is provided by a throttle bushing, with the salt flow past the bushing returning to the suction inventory by gravity.

Commercial projects typically locate the pumps above the thermal storage tanks and use the tanks as the suction inventory. This necessarily results in pumps with shaft lengths in the range of 12 to 15 m. However, pumps with shafts of these lengths are commercially available from several suppliers.

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The roofs of the storage tanks are not designed to support the weight of the pumps and motors, and a separate support structure must be cantilevered over a portion of the roof. Such an arrangement is not inherently stiff, and problems with pump vibration have occurred in some projects.

Best Practices

Guidelines and requirements provided by commercial pump vendors for the support of the pumps include the following:

- The customer must provide the rotational and translational spring rates of the pump support structure in the form of a K Matrix. If the structure does not provide sufficient rigidity, then the customer may be required to make modifications to the structure or to reduce the range of operating speed. These changes may impact the design and delivery of the pumps.

- Due to flexibility in the support structure, possible lock-out speed ranges may be required to avoid reed critical frequencies. Reed critical-frequency interference will lead to noise, vibration, and premature pump wear.

- The foundation/substructure should be pre-machined to achieve a required levelness, with deviations to more than 0.051 mm (0.002 in.) between any two points taken on the top surface of the sole plate. Levelness is measured using a precision machinist's level.

- The sole plate should be machined on both faces, with deviations in flatness not to exceed 0.167 mm/m (0.002 in./ft)

- The use of shimming should be minimized; machined surfaces are preferred. When shimming is necessary, surface-area contact should be verified by the manufacturer.

6.6.4 Reverse Flow in Salt Pumps

Background

Because of their high operating heads, receiver pumps are susceptible to reverse flow. Reverse-flow conditions can occur:

1. During the start-up sequence from primary to lag, or from lag to lag-lag.

2. Due to leakage through a discharge isolation valve.

Best Practices

- The customer must design their system based on the maximum reverse speed of the pump. Karman-Knapp diagrams are available to assist with these calculations. The definitions of the four operating quadrants in a Karman-Knapp diagram are illustrated in Figure 6-8.

- Check valves can be provided on the discharge line from each pump.

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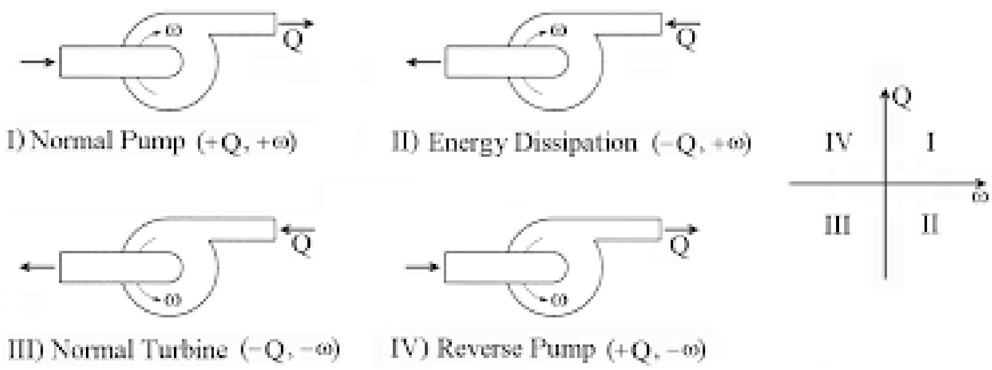

Figure 6-8. Karman-Knapp diagram for pumps

6.6.5 Minimum Diameter for Salt Piping

Background

At Solar Two, instrument standoff piping with isolation valves were placed between the pressure transducers and the process lines. The 1-in. standoff lines were heat-traced and insulated. However, even the smallest defects in the insulation, or the smallest degradation in the heat-trace cable output, resulted in salt freezing in the stagnant lines.

Best Practices

- Small-diameter lines have high surface-to-volume ratios, and it is difficult to maintain heat-trace setpoint temperatures under anything less than ideal conditions. The minimum recommended line size, even for instrument standoffs, is 4 in. to limit the surface-to-volume ratio to values that will provide reliable performance under commercial conditions. A representative installation is shown in Figure 6-9.

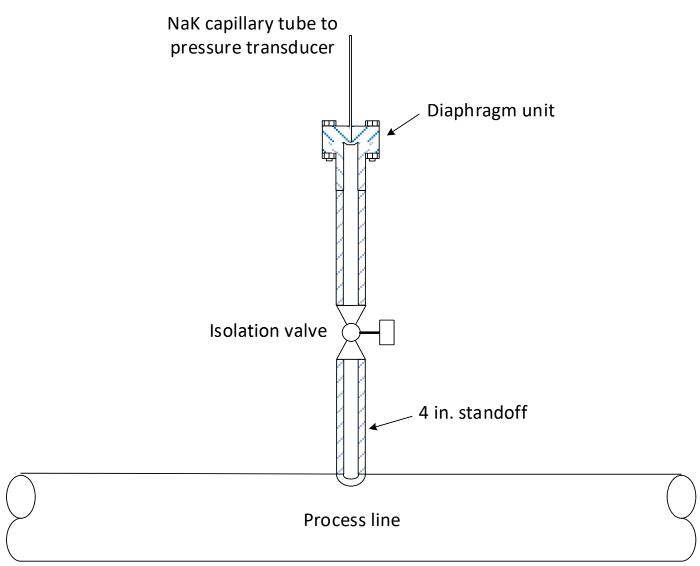

Figure 6-9. Diaphragm pressure transmitter on 4 in. standoff

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6.6.6 Supports and Anchors for Salt Piping

Background

A common approach to pipe supports and anchors is to place a calcium silicate ring around the pipe and then hold the ring in place with an external metal clamp. This approach avoids high conduction heat losses from the pipe to a metal pipe support or anchor. However, the calcium silicate rings often have a limited lifetime (~1 year) due to movements of the pipe from daily expansion and contraction cycles and impacts from pipe vibrations.

Best Practices

- Insulation rings fabricated from refractory materials that are stronger than calcium silicate are an option. Nonetheless, one pipe support and anchor that is expected to last the life of the project is a metal bridge between the pipe and the supporting steel. A sketch of a candidate metal pipe support is shown in Figure 6-10. The higher heat losses associated with a metal support will require additional heat-trace cable, in the form of a loop or an S, to be installed at the support location.

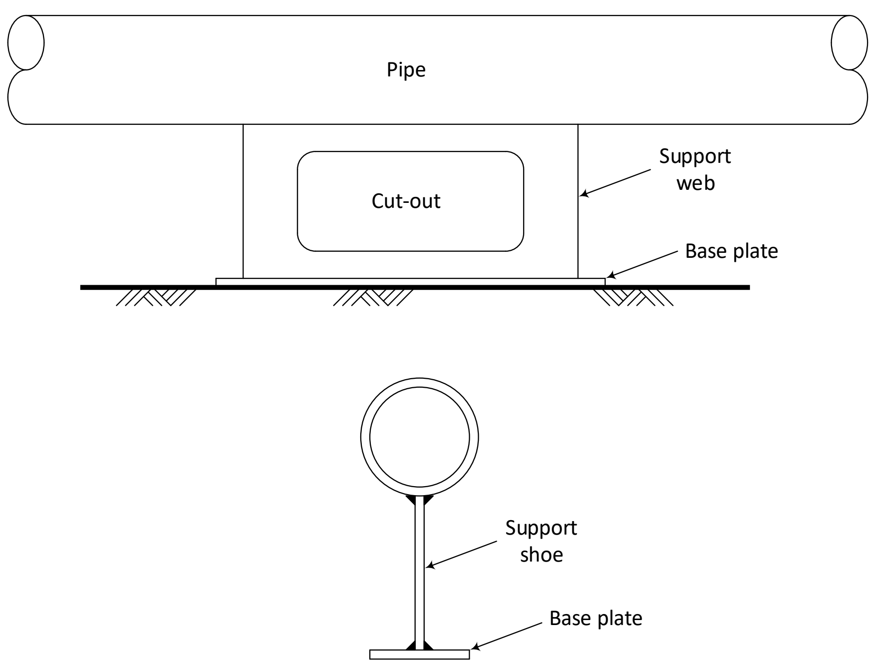

Figure 6-10. Candidate metal pipe support

- An alternate approach is a welded pipe hanger, consisting of a lug welded to the top of the pipe and hung by a rod from a structural support.

6.6.7 Salt Piping and Other Equipment in Vapor Spaces

Background

Salt has an extremely low vapor pressure, something on the order of a few pascals at 600°C. However, the vapor pressure is not zero. Salt vapors will migrate, due to diffusion, through all

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vapor spaces. Any surface that has a temperature below the freezing point of salt will condense the salt vapor. Over time, the thickness of the condensed layers can readily exceed several hundred millimeters. At Solar Two, an 8-in. tank vent line became completely blocked in a 2-year period due to a section of pipe, perhaps 0.3 m long, that had no heat-trace cable installed.

Best Practice

- For all equipment exposed to a salt-vapor space, the insulation and the heat tracing must be maintained in proper working order.

6.6.8 Valve Types and Stem Seals for Salt Valves

Stem seals for salt valves are a continuing problem. Leakage past the seals contaminates the insulation, which increases the heat losses. Also, at the operating temperatures of the heat-trace cables, the salt produces corrosive decomposition products, which leads to a rapid failure of the cables.

Background—Solar Two

The project used globe valves for process control and ball valves for isolation. Ball valves were selected because the stem needed only a one-quarter turn between open and close. As such, potential damage to the stem packing was believed to be lower than in a gate valve with a translating stem.

All valves used a stem packing consisting of alternating layers of graphite-impregnated Inconel braid and washers of Teflon.

Valves in hot-salt service used extended bonnets. With an extended bonnet, the temperature of the packing can be 250°C to 300°C lower than the design process temperature of 565°C. It was important to limit the temperature of the Teflon washers to values no higher than 350°C. Above this temperature, Teflon can decompose, which releases fluorine gas. The fluorine gas is highly corrosive and aggressively attacks the valve-stem material.

Globe valves were generally judged to be successful. However, the ball valves proved exceptionally problematic. The principal problem was binding due to corrosion layers that developed on the ball and the sealing rings. In some cases, the binding forces were high enough to plastically deform the stem. Similar binding problems occurred with gate valves if the valves were left in the closed position for a period that was long enough to develop corrosion layers on the plug and the seat. Globe valves also developed corrosion layers on the plug and the seat. However, opening the valve simply pulled the plug away from the seat, and the adherence between the corrosion surfaces was not strong enough to prevent the valve from moving.

The stem packing was judged to be marginally successful. Over time, the salt oxidized the graphite in the Inconel braids. Periodic retightening of the packing, or replacement of the packing, was needed. Further, salt seepage past the stem seals was common.

Background—Commercial Projects

As with the heat trace, the experience with valves from the Solar Two project filtered through the industry. Commercial projects adopted globe valves for process control and selected triple-offset butterfly valves, rather than ball valves, for isolation.

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Stem-sealing materials evolved somewhat to combinations of vermiculite and various fluorocarbons. Nonetheless, a robust stem-seal material combination has yet to be identified.

Best Practices

- The largest problem with salt valves is seepage past the stem seals and the associated liabilities, i.e., an increase in heat losses and corrosion of the heat-trace cables. A hermetic stem seal solves these problems. However, the only hermetic seal is a bellows seals, and bellows seals are only suitable for use on globe valves. To this end, the only valves that are recommended for salt service, for both process control and isolation, are globe valves with bellows stem seals.

  However, not everyone shares this recommendation, for the following reasons:

  - A large globe valve in isolation service is more expensive than a large triple-offset butterfly valve in isolation service.
  - Bellows seals incur a significant cost premium over conventional stem packings.
  - If the plug is moved with frozen salt in the bellows, damage to the bellows is likely.

  Offsetting the above are the following considerations:

  - The daily revenue from a commercial project can approach $150,000. If the use of a bellows seal on one valve can reduce the number of forced outage days by only one during the life of the project, then the cost of the bellows is readily justified.
  - Some valve vendors offer pre-engineered insulated enclosures that surround the bellows region. The enclosure includes thermal insulation, electric heaters, and control thermocouples. If the enclosure is maintained in proper working order, then the potential for damage to the bellows can be minimized.

- All salt valves must use butt-weld ends to accommodate daily cycles in temperature and thermal expansion.

- Body-to-bonnet gaskets should be metal O-ring or C-ring to prevent oxidation damage and leakage. Silver O-rings, with a graphite fill material, were successfully used at the Solar Two project.

- All globe and angle valves should be top-entry for ease of maintenance.

- Globe and angle valves should use a clamped-in seat. No welded or screwed-in seats should be used.

- Unbalanced valve-trim use should be maximized, and pressure-balanced trim should be minimized due to the risk of contaminates in the salt clogging the small passages in pressure-balanced valves.

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- For the downcomer throttle valves, hydraulic actuators are generally preferred. Hydraulic actuators are stiffer than pneumatic actuators, which helps to prevent oscillations in the plug position when the valves are operating at small openings (50% to 10%).

- If pneumatic actuators are used for the downcomer throttle valves, then the actuators should have a provision to include hydraulic damping.

- For the downcomer throttle valves, regardless of the type of actuator, the force produced by the actuator must have a generous margin (50% to 100%) over the minimum calculated force to prevent oscillations in the stem position at small valve openings.

- Special consideration must be given in sizing the valves and the actuators to account for the high specific gravity, and the resultant kinetic energy, of the salt. Failure to do so will result in vibration, erosion, and unstable control.

- If conventional stem packing is used, then the packing design should incorporate live (i.e., spring) loading if the O&M staff does not have sufficient experience in assessing the required tightness of the packing bolting.

6.6.9 Cavitation through Control Valves

As noted above, salt has an extremely low vapor pressure, and cavitation in control valves is not normally expected. However, cavitation damage has been noted in some salt valves in throttling service.

Background

In principle, the cavitation may not be due to the salt, but to contaminants in the salt. A potential candidate is water, which can be introduced in the system from the following sources:

- Air entering the receiver panels during the drain process, and moisture in the air condensing in the panels when the metal temperature falls below the dew point.

- Leaks in the steam generator.

Best Practice

- If water is expected in the salt, then salt valves in throttling service should be specified with anti-cavitation trim to reduce erosion. In some cases, valves specifically developed for large pressure drops (i.e., drag valves) can be selected.

6.6.10 Salt Instruments—Pressure Transmitters

Changes made to the capillary fill fluid and the installation geometry of the diaphragm units have markedly improved the reliability of pressure transmitters.

Background

In some early projects, diaphragm units were installed at the end of a vertical standoff. An isolation valve was installed in the standoff, and the standoff had a diameter of 1 in. Pressure signals were transmitted to a remote transducer through a capillary tube.

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The design had two basic problems:

- The diameter of the standoff line was too small, and any defects in the insulation or the heat tracing caused the salt in the line to freeze.

- On the hot-salt transmitters, the temperature of the diaphragm unit would slowly increase over the course of a day. This caused the pressure of the fill fluid in the capillary to increase to the point where the transducers simply read at the upper limit of their scale. Several organic fill fluids were tested, but the problem persisted.

Best Practices

The problems noted above have been largely solved at commercial projects by revising the design as follows:

- The organic fill fluid has been replaced by a eutectic mixture of sodium and potassium (NaK). The metals have very low vapor pressures, which minimizes the influence of the diaphragm temperature on the transducer reading.

- Temperature compensation is provided for the diaphragm units.

- The diaphragm units are placed in dead legs, which are connected to the main process line. In some cases, the dead leg is in the form of a horizontal "U" that is attached to a vertical section of the process line. An example installation is shown in Figure 6-11. The dead leg normally contains an isolation valve. When the system is filled or drained, the isolation valve is open; during normal operation, the valve is closed. This arrangement essentially traps a stagnant volume of salt in the dead leg. The temperature of the dead leg is then maintained at a nominal temperature 290°C by means of heat tracing. As such, (1) the temperature of the diaphragm unit remains at a constant value, which reduces the effect of temperature on the pressure reading, and (2) the same equipment can be used on both cold and hot process lines, and it provides similar results.

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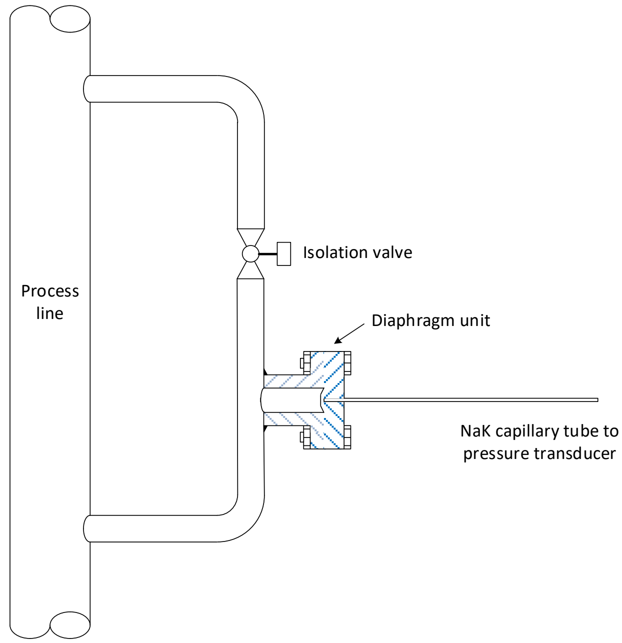

Figure 6-11. Pressure-transmitter installation

- The installation approach described above is suitable for commercial projects. However, some maintenance practices must be followed: (1) the isolation valve must be checked periodically for a full range of motion; and (2) the temperature of the dead leg must be monitored to determine if the isolation valve has developed an internal leak.

6.6.11 Salt Instruments—Flow Meters

Flow meters in salt service are notoriously problematic.

Background

Instrument testing at Sandia National Laboratories showed good experience with vortex-shedding flow meters. At that time, vortex meters had an upper temperature limit of perhaps 400°C and were available in line sizes up to at least 12 in.

In an early demonstration project, the largest line size was 8 in. As such, vortex meters could be used throughout the cold side of the plant. To monitor the flow rate of hot salt through the steam generator, a vortex meter was located at the cold end of the preheater.

In general, the reliability of the vortex meters was very good, with the random loss of a flow signal occurring perhaps once every 10 days.

Many of the line sizes in commercial plants exceed the size range for vortex meters. As a result, ultrasonic flow meters, which are available in lines sizes up to at least 48 in., are usually specified. Further, ultrasonic meters are suitable for service temperatures up to at least 600°C. Nonetheless, the experience with ultrasonic meters has been less than ideal. Common problems include the random loss of signals and susceptibility to noise in the output signal. Depending on the application, a momentary loss of signal can either be a minor annoyance or have a noticeable

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effect on the daily plant performance. As an example, flow meters are often located at the inlet to each of the two flow circuits in a salt receiver. The loss of a flow signal, even for a few seconds, is interpreted by the DCS as a loss in flow. This results in a receiver trip, followed by a receiver drain. The receiver must then be preheated, refilled, and returned to normal operation. The time required to recover from a receiver trip can range from 40 to 60 minutes, depending on the weather conditions.

Best Practices

- In locations in which a loss of a flow signal is an annoyance, a single vortex meter on the cold side or a single ultrasonic meter on the hot side is a suitable commercial practice.
- For locations in which a loss of a flow signal has a measurable detrimental effect on the plant performance, redundant vortex meters should be used on the cold side and redundant ultrasonic meters should be used on the hot side. A one-out-of-two voting logic would be used.
- Note that redundant flow meters will incur a cost premium to provide the required lengths of straight pipe, both upstream and downstream, of the meters in series.

6.7 Steam-Generation System

6.7.1 Steam-Generator Configuration

Nitrate-salt steam generators employ multiple heat exchangers, arranged in series, to convert the thermal energy in the salt into superheated steam for use by the Rankine cycle. The heat exchangers employ (1) tubes that are strength welded and then plastically deformed into a flat tubesheet, or (2) tubes that are welded to nozzles, and the nozzles are welded to a pipe that acts as a distribution header. The heat exchangers include a preheater, an evaporator, and a superheater. For reheat Rankine cycles, a reheater is also required. Numerous reliability and availability problems have occurred with the flat tubesheet designs, both in demonstration projects and commercial plants. The header-coil designs have generally offered better reliability and availability.

Background

There are two types of evaporators used in commercial steam generators: kettle boilers and forced-recirculation evaporators with a separate steam drum. In addition, natural-circulation evaporators, with a separate steam drum, have been used in demonstration projects.

The 10-MW_e Solar Two demonstration plant that operated in the late 1990s used a kettle boiler. At least one commercial plant operating today, Gemasolar, also uses this type of evaporator. The kettle boiler was selected for Solar Two because this type had been successfully deployed in the SEGS parabolic trough plants prior to Solar Two. It is called a "kettle boiler" because the evaporator and the steam drum are integrated into a single vessel. The design can be less expensive than the recirculating type because there are fewer vessels. Nonetheless, there are limits on the maximum dimensions, and therefore, the maximum thermal rating of the evaporator. Specifically, the tube bundle is placed inside the drum, and there are practical limits as to maximum diameter and the maximum shell thickness for the drum.

A kettle evaporator necessarily places the salt on the tube side. Solar Two showed that the tubes were susceptible to rupture if a series of salt-freeze events occurred. Ruptured tubes occurred early in the project due to a process deficiency that allowed feedwater that was colder than the freezing point of salt to enter the bottom of the evaporator. The design flaw was corrected by (1) relocating the inlet feedwater sparger from a point near the bottom of the water inventory to a point near the top of the water inventory, and (2) replacing the evaporator water-recirculation pumps with pumps of higher capacity. After the modifications, the system operated reliably.

After the Solar Two project, some commercial plant studies began to favor the use of forced-recirculation evaporators. Feedwater from the preheater is mixed with the water inventory in the steam drum. Recirculation pumps draw suction from the drum and supply feedwater to the evaporator. The evaporator produces a nominal mixture of 30% steam and 70% water. The mixture is sent to the drum, which separates the steam for transfer to the superheater. This type of steam generator was demonstrated at Sandia National Laboratories at a 1-MW_e scale in the 1980s, and it is in use at most commercial plants.

The recirculating design, although more complex than the kettle evaporator, offers the following control advantages during start-up, shut-down, and low-load operation:

- The recirculation water pumps can maintain water-side flow rates in the evaporator above the minimum value specified by the vendor.

- If so equipped, a separate set of recirculation pumps draws suction from the drum and transfers the saturated water to a mixing station upstream of the cold end of the preheater. The direct-contact heat exchange ensures that the (1) temperature of the mixed feedwater entering the preheater is always above the freezing point of the salt, and (2) flow rate on the water side of the preheater is above the minimum value specified by the vendor.

Best Practices

- In each of the four heat exchangers (preheater, evaporator, superheater, and reheater), the preferred shell-side fluid is salt. Should a heat exchanger freeze, the thawing process begins by activating the heat tracing on the salt piping to and from the heat exchanger, and then draining the salt lines. The heat tracing on the shell is then activated, and thawing begins on the inside surface of the shell. The liquid-film layer, as it melts and expands, leaves the heat exchanger via the inlet and outlet lines. Because the thickness of the initial film is small, the absolute volume change inside the shell is also small. This reduces the potential for plastic deformation of the shell during the majority of the thawing process.

- Due to fabrication limits on the size of kettle evaporators, and a desire to limit the number of heat exchangers, commercial projects generally default to recirculation evaporators. Forced recirculation, rather than natural circulation, is generally preferred at live steam pressures at or above 140 bar, and forced recirculation is mandatory at steam pressures approaching 170 bar. Forced recirculation allows for accurate control of flow rates and temperatures during start-up, shut-down, and low-load operation.

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- At live steam pressures below 140 bar, natural circulation is an option, and it avoids the expense of recirculation pumps.

- Forced recirculation of the preheater is recommended to ensure accurate control over salt temperatures at the cold end of the heat exchanger.

- As discussed in the sections that follow, numerous failures have occurred in the heat exchangers. To reduce the effects on plant availability, two 50% steam-generator trains are often specified and were promoted as the correct approach by the O&M staffs at operating plants. However, if the failure mechanisms can be brought under control, then one 100% steam generator might be the preferred approach for a mature commercial plant. One train reduces the number of the following parameters: heat exchangers; tube-to-tubesheet connections; piping lengths; heat-trace circuits; control valves; isolation valves; drain valves; pressure-relief valves; recirculation pumps; flow meters; pressure transmitters; level instruments; thermocouples; DCS complexity; and operator workload. However, a single train was used at Solar Two, and when it failed, the plant was down for many months to implement repair. A thorough risk study must be performed before considering the single-train approach.

6.7.2 SGS Start-Up and Shut-Down

Plant equipment must be provided, and operating procedures must be developed, to safely operate the heat exchangers during low-load operation.

Background

The heat exchangers in a steam generator typically operate through daily start-up and shut-down cycles. In the case of flat tubesheet designs, the combination of thin metal sections (shell-and-tubes) connected to thick metal sections (tubesheets) can produce transient thermal stresses that are higher than the values listed in Section II of the ASME Code. Similar effects occur in the header-coil design; however, the magnitude of the stresses can be lower due to the replacement of a relatively thick tubesheet with a relatively thin pipe section. As a result, the heat-exchanger vendor will often perform a low-cycle fatigue analysis based on the methods described in Section VIII Division 2 of the Code. The analysis will typically define operating limits for rate of temperature change (°C/min), number of thermal cycles, thermal shock (°C), and number of thermal shocks. A thermal shock is a step-change difference in temperature between the metal and either fluid.

During overnight hold periods, the heat exchangers are supplied with a flow of cold salt from the system attemperation pump. However, the low-cycle fatigue limits do not allow the steam generator to be started by simply supplying a flow of hot salt to the superheater and the reheater. It is incumbent on the EPC contractor to provide the process equipment and the control strategy such that the vendor limits can be satisfied during both start-up and shut-down.

A typical start-up sequence involves the blending of hot salt with cold salt near the entrance to the steam generator. The relative flow rates of hot salt and cold salt are adjusted such that the rate of temperature change in the mixed-salt temperature matches the vendor limit. A typical rate is 10°C/min. It can be noted that in a commercial steam generator, the rate of hot-salt addition (or the rate of cold-salt subtraction) must be controlled within an acceleration of 1.3 m^3/h (6

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gpm) per minute. This increment is perhaps 0.2% of the design flow rate of the hot-salt pump. Unless split-range control valves are provided for the start-up and shut-down sequences, the primary-circuit control valves will not have the authority to provide the required blending proportions. The problem is compounded by the very low system-pressure drops experienced during transitions. The result is high rates of temperature change and a large number of oscillations in the blended temperature. The consequences are (1) relaxation of the friction connection between the tubes and the tubesheet, (2) low-cycle fatigue failure of the tube-to-tubesheet strength weld, and, eventually, (3) leakage of steam into the salt.

Best Practices

- SGS start-up and shut-down is a complex procedure, with strict operating limits set by the vendor. As such, automation and operator training are the keys to success. Several in the CSP industry believe that simulator training of the plant operators is warranted.

- A potential start-up and shut-down process, which was successfully demonstrated at the Solar Two project, involves the following elements:

    - Check valves are provided at the discharge of both the hot-salt pump and the cold-salt attemperation pump.
    - A split-range start-up control valve is placed at the cold end of the preheater. This is the only control valve that concurrently modulates the flow from the hot-salt pump and the attemperation pump. As a result, both pumps operate against a common backpressure.
    - The discharge coefficient of the control valve is selected to provide a high system back pressure. This forces both salt pumps to operate at speeds well above their respective minimum speeds.
    - The minimum-flow recirculation control valves for both pumps are placed in fixed positions that ensure that the minimum-flow requirements are met, even if the flow from the pump to the steam generator drops to zero.
    - At the beginning of start-up, the speed of the cold-salt pump is selected such that the minimum salt flow rate, as defined by the vendor, is established. The speed of the cold-salt pump is then held constant.
    - The hot-salt pump is started and set to the minimum speed. However, the discharge pressure of the hot pump is less than the discharge pressure of the cold pump, and the check valve on the hot pump is closed.
    - The speed of the hot pump is increased. When the discharge pressure of the hot pump matches the discharge pressure of the attemperation pump, blending of hot salt with cold salt begins.
    - The speed of the hot-salt pump is increased at a rate that provides a rate of temperature change in the mixed salt equal to the vendor limit.
    - After about 25 to 30 minutes, the discharge pressure of the hot-salt pump has increased to a value such that the attemperation pump, operating at its initial fixed speed, has reached the shutoff condition. The flow from the attemperation pump

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stalls, and the discharge check valve closes. Only hot salt is now supplied to the steam generator, and the start-up transition is complete.

    - The shut-down process is the reverse of the start-up process.

- Based on the procedure above, there is necessarily a time delay between an increase in the temperature of the salt entering the superheater and reheater and the establishing of a steam flow rate through the superheater and reheater. The effect of the time delay on the fatigue life of the heat exchangers is not known. However, it is possible to install a hot-salt line and a mixing station upstream of the evaporator. It is possible to establish a flow of saturated steam through the superheater and reheater at a temperature equal to the cold-salt temperature by the following: increasing the temperature of the salt at the entrance to the evaporator prior to increasing the temperature of the salt at the entrance to the superheater and reheater, and maintaining the saturation pressure in the evaporator at a fixed value. Once these flows are established, the mixing station can be switched from a point upstream of the evaporator to a point upstream of the superheater and reheater.

6.7.3 SGS Trips

A trip of the steam generator, once in the hot condition, presents a problem as to how to safely restart the heat exchangers in an expedient manner.

Background

If the steam generator is in normal operation, and if a trip of the steam generator or the Rankine cycle occurs, flows on both the salt side and the water/steam side must be halted immediately. Specifically, the power demands of the salt pumps and the feedwater pumps are too large to be provided by a UPS. Further, in the absence of exactly matched salt-side and water/steam-side duties, potentially damaging temperature distributions could develop in the heat exchangers during the time required to start the backup diesel generator.

The metal temperatures in the evaporator and the steam drum will soon reach the saturation temperature. However, the metal temperatures in the superheater, reheater, and economizer will tend to retain the normal profiles along the flow paths in the heat exchangers.

The question then arises as to how to restart the steam generator. If the hot-salt pump is started, then the metal temperatures at the cold ends of the superheater and the reheater will quickly rise to the hot-salt temperature before a cooling flow of saturated steam can be generated in the evaporator. Alternatively, if the attemperation pump is started, then the metal temperatures at the cold ends of the superheater and reheater will immediately decay to the cold-salt temperature. In either case, the allowable rates of change in the metal temperatures will be exceeded.

Best Practices

- The best method for safely returning the heat exchangers to a safe restarting position is to drain the salt sides of the four heat exchangers, and then wait, perhaps as long as 6 to 8 hours, until conduction heat transfer on the tube side of the heat exchangers returns the metal temperature to the nominal cold-salt temperature. The heat exchangers are drained to reduce the thermal inertia and accelerate the equilibration process.

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- Due to the relatively cold feedwater in the economizer, this heat exchanger will reach the cold-salt temperature first. If the metal temperature starts to fall below the cold-salt temperature, then the electric heat tracing on the shell can be placed into service.

6.7.4 Heat-Exchanger Leaks

Heat-exchanger tubes in commercial steam generators are experiencing high failure rates. The majority of these heat exchangers are shell-and-tube designs. The header-coil designs are experiencing lower failure rates; however, there are far fewer header-coil heat exchangers in service on which to develop a reliability database.

Background

Two types of tubesheets are currently in use in commercial projects:

- Drilled flat tubesheets in the shell-and-tube designs. The ends of the tubes are seal-welded to the face of the tubesheet, and the tubes are then plastically expanded into the tubesheet. TEMA Class R requirements are usually specified.

- Header tubesheets in the header-coil designs. The tubesheet consists of a pipe section. A series of holes are drilled in the pipe, short nozzles are welded at the holes, and the tubes are then welded to the nozzles.

The flat-tubesheet design is a standard commercial offering from a wide range of manufacturers. Its principal liability is the potential for relaxation of the friction connection between the tube and the tubesheet due to high rates of temperature change or large numbers of thermal cycles.

The header-tubesheet design is available from two, and perhaps other, commercial suppliers. Because all of the internal connections are welded, the design is less susceptible to, but not immune from, the effects of thermal cycles or potential tube vibration due to high steam velocities.

A third tubesheet option, which has yet to be used in commercial service, is the internal-bore welded design. Here, nozzles are machined from a flat tubesheet. The tubes are then butt-welded to the nozzles using an automated welder working from inside the tubes. As with the header tubesheet, the internal-bore approach uses only welded connections inside the heat exchanger. This design is an optional offering from a range of commercial suppliers.

In general, the reliability of steam generators in salt service has been fair, and in some cases, poor. The problems have been almost exclusively due to internal leakage associated with failures of the tube-to-tubesheet connections or corrosion in the thin-walled tubes in shell-and-tube designs. Many projects, in anticipation of problems with the steam generator, have specified two 50% trains.

Best Practices

- Plan for tube leaks. Install 10% or more extra tubes so that plugging will not impact plant performance.

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- The high-pressure feedwater heaters in Rankine cycles have essentially the same geometry—and often operate under similar cycling conditions—as the heat exchangers in a steam generator. However, the feedwater heaters have much longer mean times to failure than the steam generator. The differences can be traced to (1) operating the steam generator outside the vendor limits on rates of temperature change and numbers of thermal cycles, and (2) poor control over the feedwater chemistry, leading to deposits of solids in the evaporator. For the steam generator to reach the required levels of commercial reliability, the following elements, in order of importance, are needed:

    1. Satisfying the vendor limits on rates of temperature change and number of thermal cycles.

    2. Controlling the water chemistry.

    3. Selecting a heat-exchanger design that uses only welded internal connections.

    4. Using one 100% train.

- If Items 1 and 2 above can be satisfied, then the reliability of the steam-generator system will have improved to the point where further reliability improvements can be reached by switching from two trains to one train. Specifically, the use of one train reduces by 50% the number of heat exchangers, recirculation pumps, control valves, isolation valves, vent valves, drain valves, pressure transmitters, flow meters, level transmitters, thermocouples, heat-trace circuits, and associated maintenance. However, two 50% steam-generator trains were clearly promoted as the correct approach by the O&M staffs at operating plants.

6.7.5 Main-Steam and Reheat-Steam Line Heating

Background

During start-up, main steam from the superheater is throttled and then sent to the cold end of the reheater. However, the temperature of the cold reheat-steam can approach the freezing point of the salt. To prevent salt from freezing at the cold end of the reheater, an electric steam heater is placed in the cold reheat-steam line. As might be expected, the steam heater is exposed to rapid thermal transients that can have a negative effect on the life of the heating elements.

Best Practices

- The electric steam heater must be generously sized, with suitable redundancy in the heating elements, to ensure that the steam generator can be reliably started each day.

- Careful consideration must be given to the relative locations of the superheater, main steam line, steam bypass stations, reheater, cold and hot reheat lines, and turbine control valves. All of the equipment should be heated simultaneously, rather than serially. Further, the length of the steam lines must be kept as short as practical to minimize the time and thermal energy consumption during steam generator and turbine start-up.

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6.7.6 Salt Drain Tank

Salt drain tanks in commercial projects have been the cause of several forced outages.

Background

A salt drain tank is provided in many projects to receive drains from the steam generator and various sections of the salt piping. A typical installation includes a carbon-steel tank with redundant pumps to remove the salt from the tank. The pumps discharge to the main cold-salt tank.

The drain-tank system is conceptually simple, but it has resulted in numerous forced plant outages. Problems include (1) tank leakage due to high corrosion rates, likely caused by problems with heat-trace control, (2) pump failures, for reasons not identified, and (3) leakage past isolation valves, which leads to persistent high-high levels in the tank. Further, the tank is fabricated from carbon steel, but the tank can receive salt at temperatures above the design temperature for carbon steel. Under some conditions, it is necessary to reduce the temperature of the drain flow by blending the flow with cold salt from the attemperation pump. As such, any failure in the attemperation circuit (pump, control valve, instruments) could result in a forced plant outage. Specifically, if the high-temperature circuits cannot be safely drained to the drain tank, then the high-temperature circuits cannot be placed into operation.

Best Practices

- The drain tank can be eliminated by elevating all of the salt equipment above the mid-point height of the salt tanks. Clearly, this leads to an increase in the structural steel, and the capital cost, of the plant. However, a reliability analysis of the drain system could show that the payback period for the additional structural steel is as short as 1 year.

- If the drain tank is shown to be the economic choice, then the drain tank should be fabricated from Type 304L stainless steel to avoid the complexity, and the availability penalties, of the attemperation equipment.

6.7.7 Steam-Generation System Recirculation Water Pump

Reliability and availability problems have been experienced with the water-recirculation pumps in the steam generator.

Background

For forced-recirculation steam generators, recirculation pumps are located between the steam drum and the evaporator. Some steam-generator designs also use a separate set of recirculation pumps between the steam drum and the cold end of the preheater. In the latter, saturated water from the drum is blended with feedwater from the Rankine cycle to provide a mixed feedwater temperature, at the entrance to the preheater, that is high enough to prevent salt from freezing at the cold end of the preheater.

The recirculation pumps are generally quite reliable, and mean time between failures are often measured in years. However, some projects have experienced operating problems and high failure rates, as noted below:

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- Vibrations and seizures due to internal rubbing. The source is likely deformation of the pump casing due to nozzle loads exceeding allowable values. The high nozzle loads, in turn, are due to misalignment between the pump flanges and the piping flanges. Other potential sources of casing deformations include starting a pump from the cold condition without sufficient preheating, or starting a pump that has a vertical temperature gradient larger than the vendor limit.

- Seal failures, likely due to solid particles in the feedwater system. The source of the particles may be flow-accelerated corrosion in the condensate system brought on by poor water-chemistry control.

Best Practices

- The shaft seal on the recirculating water pumps have experienced frequent failures. Providing redundant pumps allows replacement of the seal without affecting the availability of the plant.

- To avoid excessive nozzle loads on the pump casing, the piping must be installed to the dimensions shown in the isometric drawings. However, this can, at times, only be the ideal case. Construction schedules, the availability of pipe fitters, and field changes to the locations of supports, anchors, and valves can lead to differences in expected pipe locations and actual pipe locations. This, in turn, can lead to circumstances in which the pipe is forced into alignment with the pumps. One approach to avoiding excessive loads on the pump is to install the piping on the pumps first and then build the piping out from the pump. However, this has the potential for moving large and unexpected loads to a different point in the piping. The best long-term solution is to incorporate any field changes in the piping into the isometric drawings, repeat the stress analysis, and modify the supports and anchors such that the piping is aligned with the pumps.

- To control pump-casing temperatures, reverse flow circuits with orifices should be installed to keep the idle pumps in a warm condition. Also, interlocks should be provided to prevent the operators from starting a pump in the cold condition, or starting a pump with a top-to-bottom temperature difference that is greater than the vendor limits.

- To limit potential damage to the seals due to solid-particle erosion, careful control over the condensate and feedwater chemistries must be maintained. Additional protection measures include (1) filters in the seal water-flushing loop and (2) extending the recirculation-pump suction-line nozzles some distance into the drum to allow the drum to act as a particle trap.

6.7.8 SGS Layup

Best Practice

If the heat exchangers are to be drained and allowed to cool, then corrosion can be minimized by blanketing the equipment with nitrogen.

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6.7.9 SGS / Plant-Safety Relief Valves

Background

Between 50 and 100 relief valves are typically installed in a commercial project, many of these within the SGS. Unnecessary plant outages have occurred due to damage imposed on relief valves during plant commissioning and subsequent commercial operation.

Best Practices

Plant-outage times can be reduced if the following practices are adopted:

- Inspect the relief valves during commissioning to ensure that test gags have been removed. Gags are installed to keep the valves closed during system hydrostatic tests, and they must be removed after the tests to make the valve functional and to prevent damage to the valve spindle.

- To test and perform maintenance on many of the relief valves, the valves must be removed from the system and tested in a shop. To facilitate removal, relief valves in water, steam, and air service should be mounted using a bolted flange.

- Relief valves in salt service should always be welded in place. Welding the valves complicates the testing process because the valves must be cut out for inspection and then rewelded. However, the consequences and the costs of salt leakage from a bolted connection are much higher than the complexity and the cost of cutting and rewelding.

6.8 Power Plant

6.8.1 Rankine Cycle

Problems have occurred with maintaining level in the drain-cooler section of the lowest-pressure feedwater heater.

Background

In the lowest-pressure extraction feedwater heater, the difference in pressure between the shell of the feedwater heater and the condenser is typically small. Under certain conditions, the pressure difference may not be sufficient to move the condensate from the drain cooler into the condenser. A common solution is to add a drain pump, which takes suction from the drain cooler and feeds the condensate forward to the next higher-pressure extraction feedwater heater. However, in one commercial project, it was not possible to maintain a consistent level in the drain-cooler section, and the drain pump would trip due to two-phase flow entering the pump.

Best Practice

- The design pressure for the last extraction feedwater heater must be high enough such that adequate control of the lowest-pressure feedwater heater can be maintained over the full range of turbine outputs. The full range of turbine conditions includes not only turbine output, but also combinations of main-steam pressure, main-steam temperature, hot reheat-steam pressure, and hot reheat-steam temperature that deviate from normally

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expected values. The deviations in steam conditions are due to the receiver operating, for extended periods, with outlet temperatures in the range of 510°C to 565°C.

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Appendix A. CSP Project Database

ProjectName	Op	Country	Year in service	Technology	Size Gross MWe	TES Capacity hrs	Owner	EPC	Operator	IE/LTA	Supplier			
											HX	Col/ Hel	Rec	Other
Agua Prieta II ISCC	1	MX	2013	Trough	15	0					x			
Andasol-1	1	ES	2008	Trough	50	7.5	x	x	x		x	x		
Andasol-2	1	ES	2009	Trough	50	7.5	x	x	x		x	x		
Andasol-3	1	ES	2011	Trough	50	7.5						x		
Arcosol 50 - Valle 1	1	ES	2011	Trough	49.9	7.5	x	x	x	x		x		
Arenales	1	ES	2013	Trough	50	7		x		x	x			v
Ashalim Tower	1	IS	2018	Tower	121	0						x		
Ashalim Trough	1	IS	2018	Trough	121	4.5		x			x	x		
Aste 1A	1	ES	2012	Trough	50	8		x			x	x		
Aste 1B	1	ES	2012	Trough	50	8		x			x	x		
Astexol II	1	ES	2012	Trough	50	8					x	x		
Bokpoort	1	ZA	2016	Trough	55	9.3	x	x	x			x		v
Borges Termosolar	1	ES	2012	Trough	25	0	x		x		x			
Casablanca	1	ES	2013	Trough	50	7.5	x	x		x	x	x		v
Cerro Dominator - Construction	0	CH		Tower	110	17.5	x	x	x			x		
CGN Delingha 50MW	1	CN	2018	Trough	50	9								
Crescent Dunes	1	US	2015	Tower	110	10	x	x	x	x	x		x	v
DEWA Tower Project - Construction	0	UAE		Tower	100	10	x	x	x					
DEWA Trough Unit 1 - Construction	0	UAE		Trough	200	10	x	x	x		x			
DEWA Trough Unit 2 - Construction	0	UAE		Trough	200	10	x	x	x		x			
DEWA Trough Unit 3 - Construction	0	UAE		Trough	200	10	x	x	x		x			
Enerstar	1	ES	2013	Trough	50	0				x				
Extresol-1	1	ES	2010	Trough	49.9	7.5	x	x	x	x	x	x		
Extresol-2	1	ES	2010	Trough	49.9	7.5	x	x	x	x	x	x		
Extresol-3	1	ES	2012	Trough	50	7.5	x	x	x	x	x	x		
Gemasolar Thermosolar Plant	1	ES	2011	Tower	19.9	15	x	x	x			x	x	v
Genesis - Unit 1	1	US	2014	Trough	144	0	no	x	no			x		
Genesis - Unit 2	1	US	2014	Trough	144	0	no	x	no			x		
Godawari Solar Project	1	IN	2013	Trough	50	0						x		
Guzmán	1	ES	2012	Trough	50	0		x				x		
Helioenergy 1	1	ES	2011	Trough	50	0	x	x	x		x	x		
Helioenergy 2	1	ES	2012	Trough	50	0	x	x	x		x	x		
Helios I	1	ES	2012	Trough	50	0	x	x	x		x	x		
Helios II	1	ES	2012	Trough	50	0	x	x	x		x	x		
Ibersol Ciudad Real (Puertollano)	1	ES	2009	Trough	50	0								
Ilanga	1	ZA	2018	Trough	100	5		x			x	x		
ISCC Ain Beni Mathar	1	MA	2010	Trough	20	0		x						
ISCC Hassi R'mel	1	DZ	2011	Trough	20	0		x	x					
ISCC Kuraymat	1	EG	2011	Trough	20	0								
Ivanpah SEGS 1	1	US	2014	Tower	126	0	x		x			x		
Ivanpah SEGS 2	1	US	2014	Tower	133	0	x		x			x		
Ivanpah SEGS 3	1	US	2014	Tower	133	0	x		x			x		
Kathu Solar Park	1	ZA	2018	Trough	100	4.5		x			x	x		v
KaXu Solar One	1	ZA	2015	Trough	100	2.5	x	x	x		x	x		
Khi Solar One	1	ZA	2016	Tower	50	2	x	x	x			x	x	
La Africana	1	ES	2012	Trough	50	7.5		x	x	x		x		v
La Dehesa	1	ES	2011	Trough	49.9	7.5		x			x			
La Florida	1	ES	2010	Trough	50	7.5		x			x			
La Risca (Alvarado)	1	ES	2009	Trough	50	0	x		x		x			
Lebrija 1	1	ES	2011	Trough	50	0					x			
Majadas I	1	ES	2010	Trough	50	0	x	x	x					
Manchasol-1	1	ES	2011	Trough	49.9	7.5	x	x	x	x	x	x		
Manchasol-2	1	ES	2011	Trough	50	7.5	x	x	x	x	x	x		
Martin	1	US	2010	Trough	75	0	x		x					
Megha Solar Plant	1	IN	2014	Trough	50	0								
Mojave Solar Project - Apha	1	US	2014	Trough	140	0	x	x	x			x		
Mojave Solar Project - Beta	1	US	2014	Trough	140	0	x	x	x			x		
Morón	1	ES	2012	Trough	50	0					x	x		
Nevada Solar One	1	US	2007	Trough	75	0	x		x					
NOOR Ouarzazate I	1	MA	2015	Trough	160	3	x	x	x		x	x		v
NOOR Ouarzazate II	1	MA	2018	Trough	200	7	x	x	x		x	x		v
NOOR Ouarzazate III	1	MA	2018	Tower	150	7	x	x	x		x	x	x	v

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ProjectName	Op	Country	Year in service	Technology	Size Gross MWe	TES Capacity hrs	Owner	EPC	Operator	IE/LTA	Supplier			
											HX	Col/ Hel	Rec	Other
Olivenza 1	1	ES	2012	Trough	50	0								
Orellana	1	ES	2012	Trough	50	0	x	x	x		x	x		
Palma del Río I	1	ES	2011	Trough	50	0	x	x	x		x			
Palma del Río II	1	ES	2010	Trough	50	0	x	x	x		x			
Planta Solar 10	1	ES	2007	Tower	11.02	1	x	x	x	x		x	x	
Planta Solar 20	1	ES	2009	Tower	20	1	x	x	x	x		x	x	
SEGS I - Decommissioned 2016	0	US	1985	Trough	33	3								
SEGS II - Decommissioned 2016	0	US	1986	Trough	33	0								
SEGS III	1	US	1987	Trough	33	0	no		no					
SEGS IV	1	US	1987	Trough	33	0	no		no					
SEGS IX	1	US	1991	Trough	86	0	x		x					
SEGS V	1	US	1988	Trough	33	0	no		no					
SEGS VI - Decommissioned 2019	0	US	1989	Trough	33	0	no		no					
SEGS VII - Decommissioned 2019	0	US	1989	Trough	33	0	no		no					
SEGS VIII	1	US	1990	Trough	89	0	x		x					
Shagaya	1	IN	2018	Trough	50	10					x			
Shams 1	1	UAE	2013	Trough	100	0		x			x	x		
Solaben 1	1	ES	2013	Trough	50	0	x	x	x		x	x		
Solaben 2	1	ES	2012	Trough	50	0	x	x	x	x	x	x		
Solaben 3	1	ES	2012	Trough	50	0	x	x	x		x	x		
Solaben 6	1	ES	2013	Trough	50	0	x	x	x		x	x		
Solacor 1	1	ES	2012	Trough	50	0	x	x	x		x	x		
Solacor 2	1	ES	2012	Trough	50	0	x	x	x		x	x		
Solana Generating Station	1	US	2013	Trough	280	6	x	x	x		x	x		v
Solnova 1	1	ES	2009	Trough	50	0	x	x	x		x	x		
Solnova 3	1	ES	2009	Trough	50	0	x	x	x		x	x		
Solnova 4	1	ES	2009	Trough	50	0	x	x	x		x	x		
SunCan Dunhuang 10 MW Phase I	1	CN	2016	Tower	10	15								v
Suncan Dunhuang 100MW MS Tower	1	CN	2018	Tower	100	11								
Supcon Delingha 10MW MS Tower	1	CN	2017?	Tower	10	2								
Supcon Delingha 50MW MS Tower	1	CN	2018	Tower	50	7								
Termesol 50 - Valle 2	1	ES	2011	Trough	49.9	7.5	x	x	x	x		x		
Termosol 1	1	ES	2013	Trough	50	9	no	x	no	x		x		
Termosol 2	1	ES	2013	Trough	50	9	no	x	no	x		x		
Villena?	1	ES	2013	Trough	50	0		x				x		
Waad Al-Shamal	1	SA	2019	Trough	50	0					x			v
Xina Solar One	1	ZA	2017	Trough	100	5.5	x	x	x		x	x		v

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Appendix B. Project-Related Issue Summary Charts

To help identify which issues are most important, each issue entered in the database was given an impact score and a risk level. The impact score identified the potential impact of the issue to the project, how significant of an impact on plant performance, cost, or schedule. The impact score was ranked as 1 (low) to 5 (high). The risk level was an indication of how likely the problem was to happen. A risk level of 1 meant that the problem was rarely experienced or maybe was only associated with a problem at a single plant. A risk level of 5 meant that it was a common problem or could affect many plants. The scores are multiplied together to create a Priority Score. Priority scores can range from 1 to 25 for each issue. The ranking is of course subjective, but it is an attempt to give some quantification to the importance of issues.

The most significant issues were brought up by multiple participants. The number of "occurrences" DOES NOT correspond to the number of times some kind of incident or issue occurred at a plant, but rather, the number of times it was mentioned by people who often overlap in terms of representing a single plant. We assume that the number of occurrences that an issue is mentioned indicates how important stakeholders think an issue is.

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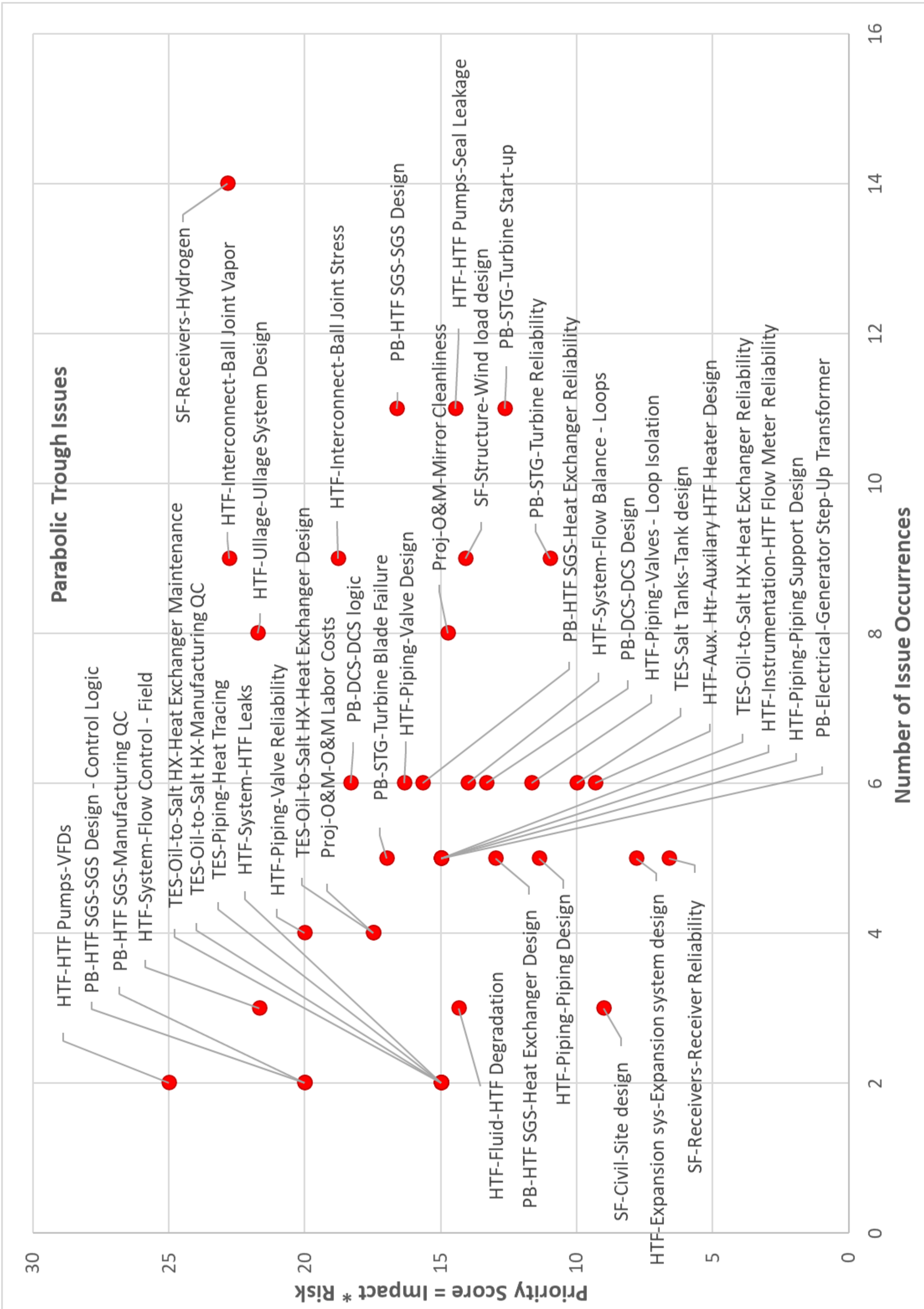

Figure B-1. Parabolic trough technology issues

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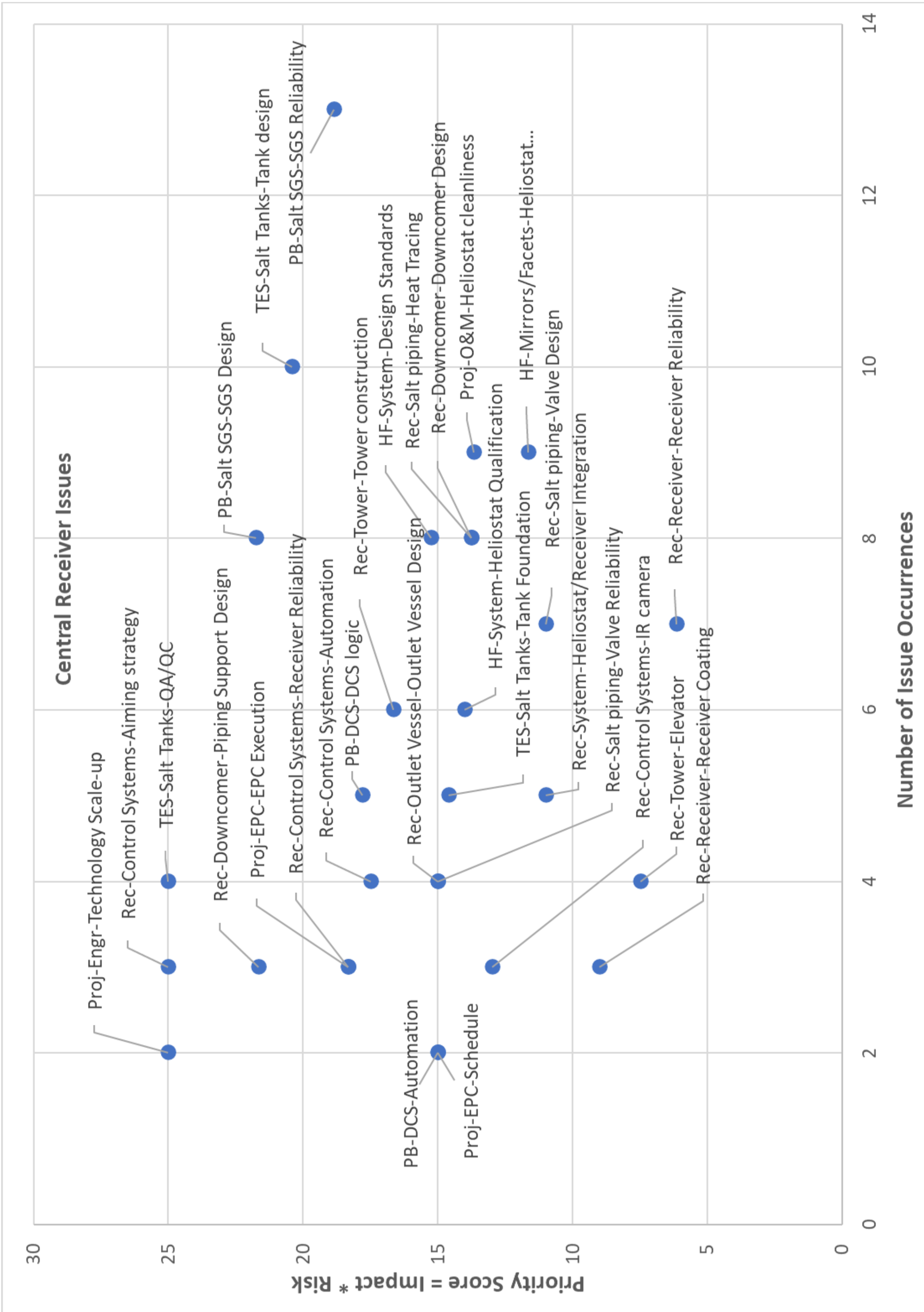

Figure B-2. Central receiver technology issues

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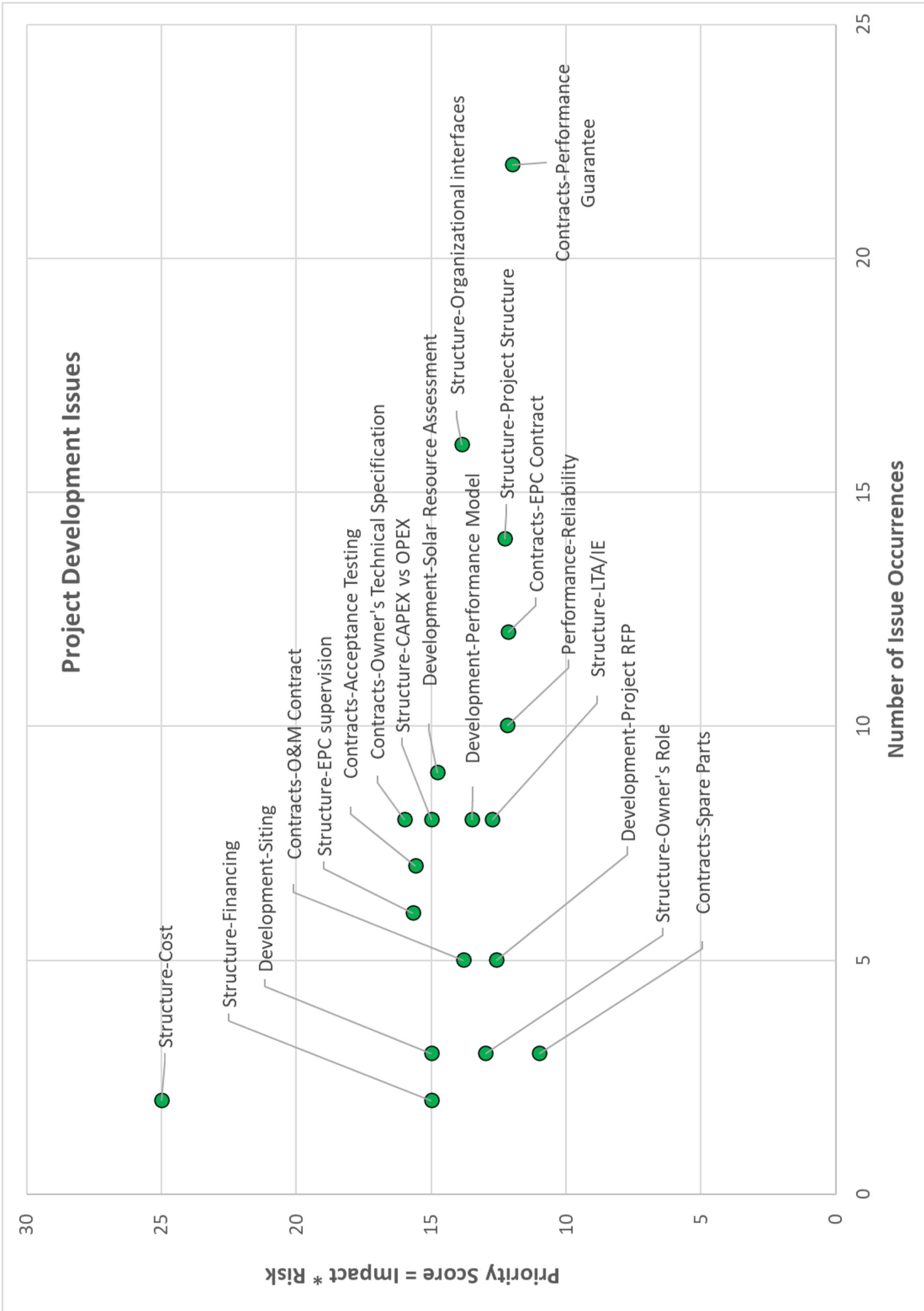

Figure B-3. Project development issues

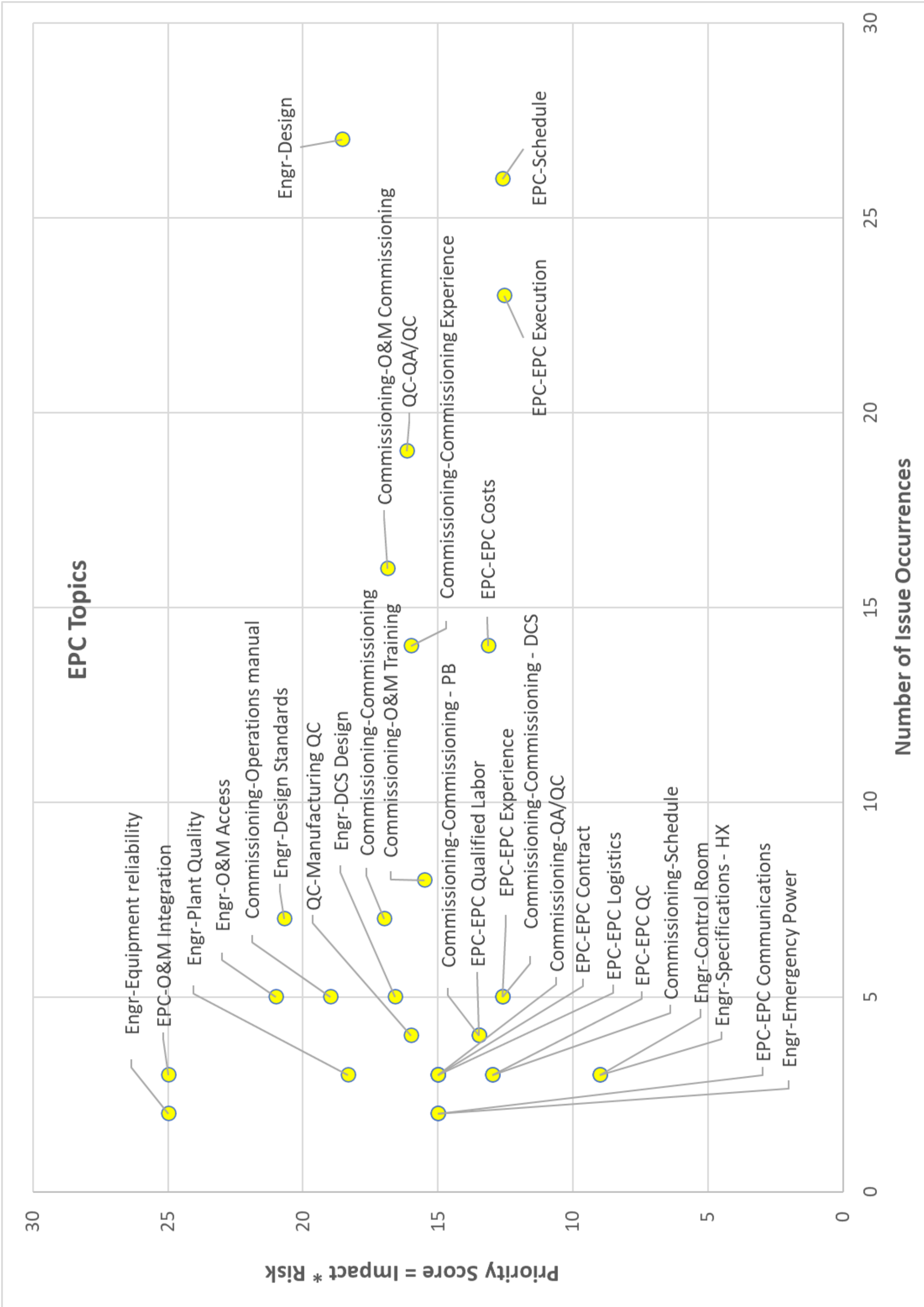

Figure B-4. EPC issues

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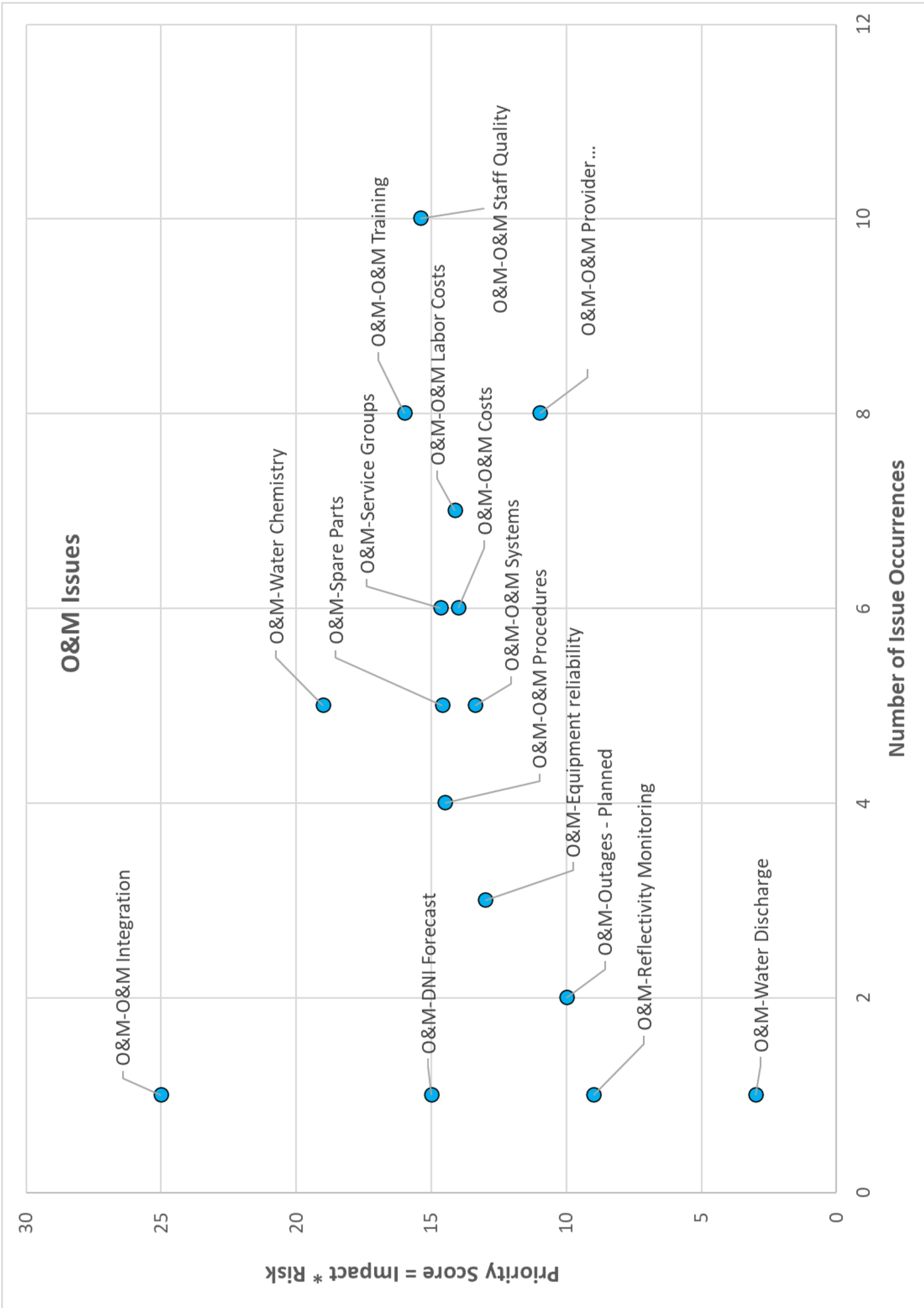

Figure B-5. O&M issues

Appendix C. Issue Database Summary

To help identify which issues are most important, each issue entered in the database was given an impact score and a risk level. The impact score identified the potential impact of the issue to the project, how significant of an impact on plant performance, cost, or schedule. The impact score was ranked as 1 (low) to 5 (high). The risk level was an indication of how likely the problem was to happen. A risk level of 1 meant that the problem was rarely experienced or maybe was only associated with a problem at a single plant. A risk level of 5 meant that it was a common problem or could affect many plants. The scores are multiplied together to create a Priority Score. Priority scores can range from 1 to 25 for each issue. The ranking is, of course, subjective, but it is an attempt to give some quantification to the importance of issues.

The most significant issues were brought up by multiple participants. The number of "occurrences" DOES NOT correspond to the number of times some kind of incident or issue occurred at a plant, but rather, the number of times it was mentioned by people who often overlap in terms of representing a single plant. We assume that the number of occurrences that an issue is mentioned indicates how important stakeholders think an issue is.

Table C-1. Parabolic Trough Technology Issues in Rank Order

Tech	Syst	SubComponent	Issue Type	Occur	Priority	Weight
PT	SF	Receivers	Hydrogen	14	22.86	320
PT	HTF	Interconnect	Ball Joint Vapor	9	22.78	205
PT	PB	HTF SGS	SGS Design	11	16.64	183
PT	HTF	Ullage	Ullage System Design	8	21.75	174
PT	HTF	Interconnect	Ball Joint Stress	9	18.78	169
PT	HTF	HTF Pumps	Seal Leakage	11	14.45	159
PT	PB	STG	Turbine Start-Up	11	12.64	139
PT	SF	Structure	Wind load design	9	14.11	127
PT	Proj	O&M	Mirror Cleanliness	8	14.75	118
PT	PB	DCS	DCS Logic	6	18.33	110
PT	PB	STG	Turbine Reliability	9	11.00	99
PT	HTF	Piping	Valve Design	6	16.33	98
PT	PB	HTF SGS	Heat Exchanger Reliability	6	15.67	94
PT	PB	STG	Turbine Blade Failure	5	17.00	85
PT	HTF	System	Flow Balance - Loops	6	14.00	84
PT	HTF	Piping	Valve Reliability	4	20.00	80
PT	PB	DCS	DCS Design	6	13.33	80
PT	HTF	Instrumentation	HTF Flow Meter Reliability	5	15.00	75
PT	HTF	Piping	Piping Support Design	5	15.00	75
PT	PB	Electrical	Generator Step-Up Transformer	5	15.00	75

Tech	Syst	SubComponent	Issue Type	Occur	Priority	Weight
PT	TES	Oil-to-Salt HX	Heat Exchanger Reliability	5	15.00	75
PT	HTF	Piping	Valves - Loop Isolation	6	11.67	70
PT	Proj	O&M	O&M Labor Costs	4	17.50	70
PT	TES	Oil-to-Salt HX	Heat Exchanger Design	4	17.50	70
PT	HTF	System	Flow Control - Field	3	21.67	65
PT	PB	HTF SGS	Heat Exchanger Design	5	13.00	65
PT	TES	Salt Tanks	Tank Design	6	10.00	60
PT	HTF	Piping	Piping Design	5	11.40	57
PT	HTF	Aux. Htr	Auxiliary HTF Heater Design	6	9.33	56
PT	HTF	HTF Pumps	VFDs	2	25.00	50
PT	HTF	Fluid	HTF Degradation	3	14.33	43
PT	PB	HTF SGS	Manufacturing QC	2	20.00	40
PT	PB	HTF SGS	SGS Design - Control Logic	2	20.00	40
PT	HTF	Expansion Sys	Expansion System Design	5	7.80	39
PT	SF	Receivers	Receiver Reliability	5	6.60	33
PT	HTF	System	HTF Leaks	2	15.00	30
PT	TES	Oil-to-Salt HX	Heat Exchanger Maintenance	2	15.00	30
PT	TES	Oil-to-Salt HX	Manufacturing QC	2	15.00	30
PT	TES	Piping	Heat Tracing	2	15.00	30
PT	SF	Civil	Site Design	3	9.00	27
PT	HTF	Fluid	Safety	1	25.00	25
PT	HTF	Fluid	HTF Properties	1	25.00	25
PT	HTF	Interconnect	Limited Suppliers	1	25.00	25
PT	HTF	Interconnect	Flex Hoses	1	25.00	25
PT	HTF	Piping	Insulation Quality	1	25.00	25
PT	HTF	System	HTF Flow Control	1	25.00	25
PT	PB	Steam Cycle	Water Supply	1	25.00	25
PT	SF	Control System	FSC Design	1	25.00	25
PT	PB	Steam Cycle	VFDs	2	12.00	24
PT	Proj	O&M	O&M Provider Quality	2	12.00	24
PT	SF	System	Design Standards	2	12.00	24
PT	SF	Instr. & LOC	Solar Field Control System	3	7.67	23
PT	SF	Mirrors	Mirror Breakage	3	7.67	23
PT	PB	Steam Cycle	Gland Steam System Design	2	9.00	18

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Tech	Syst	SubComponent	Issue Type	Occur	Priority	Weight
PT	PB	Steam Cycle	Valve Reliability	2	9.00	18
PT	TES	Piping	Valve Reliability	2	9.00	18
PT	TES	Salt Pumps	Salt Pump Design	2	9.00	18
PT	HTF	Expansion Sys	Safeties	1	15.00	15
PT	HTF	Piping	Pump Bellows Leakage	1	15.00	15
PT	HTF	Piping	Welding	1	15.00	15
PT	PB	Aux. Syst	Heat Tracing	1	15.00	15
PT	PB	Aux. Syst	Cooling - Auxiliary	1	15.00	15
PT	PB	Electrical	Electrical System Design	1	15.00	15
PT	PB	HTF SGS	SGS Reliability	1	15.00	15
PT	Proj	EPC	EPC Experience	1	15.00	15
PT	Proj	O&M	O&M Staff Quality	1	15.00	15
PT	Proj	Structure	Organizational Interfaces	1	15.00	15
PT	SF	Elect &I&C	Electrical System Design	1	15.00	15
PT	SF	Elect &I&C	Lightning	1	15.00	15
PT	TES	Piping	Control Valve Leaks	1	15.00	15
PT	SF	Instr. & LOC	Solar Field Communication	2	7.00	14
PT	HTF	Piping	HTF Vapor - Venting	1	9.00	9
PT	HTF	System	Temperature Control - Loop	1	9.00	9
PT	PB	Aux. Syst	Instrument Air	1	9.00	9
PT	PB	Civil	Turbine Foundations	1	9.00	9
PT	PB	Steam Cycle	Condenser Tube Material	1	9.00	9
PT	PB	STG	Generator Reliability	1	9.00	9
PT	PB	STG	Lube Oil System	1	9.00	9
PT	Proj	EPC	EPC Execution	1	9.00	9
PT	Proj	EPC	Schedule	1	9.00	9
PT	Proj	O&M	O&M Costs	1	9.00	9
PT	Proj	O&M	Capital Improvement	1	9.00	9
PT	Proj	O&M	Solar Field Maintenance	1	9.00	9
PT	SF	Civil	Foundation - Collector	1	9.00	9
PT	SF	Elect &I&C	Grounding - SF	1	9.00	9
PT	SF	Instr. & LOC	Inclinometer	1	9.00	9
PT	SF	Structure	Corrosion - Solar Field	1	9.00	9
PT	SF	System	Collector Temperature Control	1	9.00	9

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Tech	Syst	SubComponent	Issue Type	Occur	Priority	Weight
PT	TES	Salt Pumps	Pump Alignment	1	9.00	9
PT	HTF	Piping	HTF Leaks	1	5.00	5
PT	PB	Electrical	Generator Breaker	1	5.00	5
PT	TES	Salt Pumps	Seal Leakage	1	5.00	5
PT	PB	STG	Turbine Heating Blankets	1	3.00	3
PT	SF	Drives	Seal Leakage - SF Drives	1	3.00	3
PT	SF	Civil	Water Supply	1	1.00	1

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Table C-2. Central Receiver Technology Issues in Rank Order

Tech	System	Subsystem	Issue Type	Occurrence	Priority	Weight
CR	PB	Salt SGS	SGS Reliability	13	18.85	245
CR	TES	Salt Tanks	Tank design	10	20.40	204
CR	PB	Salt SGS	SGS Design	8	21.75	174
CR	Proj	O&M	Heliostat cleanliness	9	13.67	123
CR	HF	System	Design Standards	8	15.25	122
CR	Rec	Downcomer	Downcomer Design	8	13.75	110
CR	Rec	Salt piping	Heat Tracing	8	13.75	110
CR	HF	Mirrors/Facets	Heliostat Optical Quality	9	11.67	105
CR	Rec	Tower	Tower construction	6	16.67	100
CR	TES	Salt Tanks	QA/QC	4	25.00	100
CR	PB	DCS	DCS logic	5	17.80	89
CR	HF	System	Heliostat Qualification	6	14.00	84
CR	Rec	Salt piping	Valve Design	7	11.00	77
CR	Rec	Control Systems	Aiming strategy	3	25.00	75
CR	TES	Salt Tanks	Tank Foundation	5	14.60	73
CR	Rec	Control Systems	Automation	4	17.50	70
CR	Rec	Downcomer	Piping Support Design	3	21.67	65
CR	Rec	Outlet Vessel	Outlet Vessel Design	4	15.00	60
CR	Rec	Salt piping	Valve Reliability	4	15.00	60
CR	Proj	EPC	EPC Execution	3	18.33	55
CR	Rec	Control Systems	Receiver Reliability	3	18.33	55
CR	Rec	System	Heliostat/Receiver Integration	5	11.00	55
CR	Proj	Engr	Technology Scale-up	2	25.00	50
CR	Rec	Receiver	Receiver Reliability	7	6.14	43
CR	Rec	Control Systems	Infrared camera	3	13.00	39
CR	PB	DCS	Automation	2	15.00	30
CR	Proj	EPC	Schedule	2	15.00	30
CR	Rec	Tower	Elevator	4	7.50	30
CR	Rec	Receiver	Receiver Coating	3	9.00	27
CR	HF	Control	Design Specifications	1	25.00	25
CR	HF	Mirrors/Facets	Heliostat cleanliness	1	25.00	25
CR	Proj	EPC	Welding	1	25.00	25
CR	Rec	System	Receiver Reliability	3	8.33	25
CR	TES	Salt Tanks	Salt Heater Design	3	8.33	25

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Tech	System	Subsystem	Issue Type	Occurrence	Priority	Weight
CR	HF	Control	Beam-Characterization System Calibration	2	12.00	24
CR	HF	Drives	Heliostat availability	4	6.00	24
CR	HF	Mirrors/Facets	Facet blocking	2	9.00	18
CR	HF	Power/Wiring	Electrical System Design	2	9.00	18
CR	TES	Salt	Corrosion	2	9.00	18
CR	HF	Control	Heliostat/Receiver Integration	1	15.00	15
CR	HF	Drives	Drive qualification	1	15.00	15
CR	PB	Steam Cycle	Valve Reliability	1	15.00	15
CR	Proj	Structure	EPC Experience	1	15.00	15
CR	Rec	Control Systems	Flux Meter	1	15.00	15
CR	Rec	Receiver	Automation	1	15.00	15
CR	TES	Salt	Water Emulsion	1	15.00	15
CR	Rec	Downcomer	Downcomer Control	3	4.33	13
CR	TES	Hot Salt Pump	Pump Design	3	4.33	13
CR	HF	Mirrors/Facets	Heliostat availability	2	6.00	12
CR	PB	STG	Turbine Reliability	2	6.00	12
CR	PB	Steam Cycle	Pump Reliability	3	3.67	11
CR	PB	Salt SGS	Pump alignment	2	5.00	10
CR	PB	STG	Generator Reliability	2	5.00	10
CR	Rec	Receiver	Receiver Design	2	5.00	10
CR	HF	Civil	Heliostat cleanliness	1	9.00	9
CR	HF	Enviro	Heliostat flux hazard	1	9.00	9
CR	HF	Helio Structure	Pedestal Installation	1	9.00	9
CR	HF	Power/Wiring	Lightning	1	9.00	9
CR	HF	System	Optics vs. cost	1	9.00	9
CR	PB	Aux. Syst	Water Supply	1	9.00	9
CR	PB	DCS	Instrument Reliability	1	9.00	9
CR	Rec	Cold Salt Pump	Pump Reliability	1	9.00	9
CR	Rec	Salt piping	Piping Design	1	9.00	9
CR	TES	Piping	Insulation Quality	1	9.00	9
CR	PB	Aux. Syst	Fire System Design	1	5.00	5
CR	TES	Hot Salt Pump	Pump Reliability	1	5.00	5
CR	HF	Civil	Site preparation	1	3.00	3
CR	PB	Aux. Syst	Hybrid Cooling	1	3.00	3

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Tech	System	Subsystem	Issue Type	Occurrence	Priority	Weight
CR	PB	Electrical	Design Specifications	1	3.00	3
CR	Rec	Salt piping	Safeties	1	3.00	3
CR	TES	Salt Tanks	Testing Standards	1	3.00	3

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Table C-3. Project Development Issues in Rank Order

Category	Subcategory	Issue Type	Count	Priority	Weight
Project	Contracts	Performance Guarantee	22	12.00	264
Project	Structure	Organizational interfaces	16	13.88	222
Project	Structure	Project Structure	14	12.29	172
Project	Contracts	EPC Contract	12	12.17	146
Project	Development	Solar Resource Assessment	9	14.78	133
Project	Contracts	Owner's Technical Specification	8	16.00	128
Project	Performance	Reliability	10	12.20	122
Project	Structure	CAPEX vs. OPEX	8	15.00	120
Project	Contracts	Acceptance Testing	7	15.57	109
Project	Development	Performance Model	8	13.50	108
Project	Structure	LTA/IE	8	12.75	102
Project	Structure	EPC supervision	6	15.67	94
Project	Contracts	O&M Contract	5	13.80	69
Project	Development	Project RFP	5	12.60	63
Project	Structure	Cost	2	25.00	50
Project	Development	Siting	3	15.00	45
Project	Structure	Owner's Role	3	13.00	39
Project	Contracts	Spare Parts	3	11.00	33
Project	Structure	Financing	2	15.00	30
Project	Structure	Competition	1	25.00	25
Project	Contracts	PPA Contract	2	12.00	24
Project	Contracts	Lender Contract	2	12.00	24
Project	Contracts	Contract Structure	1	15.00	15
Project	Structure	Experience - Project	1	15.00	15
Project	Structure	Early Works	1	15.00	15
Project	Contracts	Testing Standards	1	9.00	9
Project	Contracts	Technical Expertise	1	9.00	9
Project	Performance	Startup Time	1	5.00	5
Project	Performance	System Derating	1	3.00	3

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Table C-4. Project Execution (EPC) Issues in Rank Order

Category	Subcategory	Issue Type	Count	Priority	Weight
Project	Engr	Design	27	18.56	501
Project	EPC	Schedule	26	12.62	328
Project	QC	QA/QC	19	16.16	307
Project	EPC	EPC Execution	23	12.57	289
Project	Commissioning	O&M Commissioning	16	16.88	270
Project	Commissioning	Commissioning Experience	14	16.00	224
Project	EPC	EPC Costs	14	13.14	184
Project	Engr	Design Standards	7	20.71	145
Project	Commissioning	O&M Training	8	15.50	124
Project	Commissioning	Commissioning	7	17.00	119
Project	Engr	O&M Access	5	21.00	105
Project	Commissioning	Operations manual	5	19.00	95
Project	Engr	DCS Design	5	16.60	83
Project	EPC	O&M Integration	3	25.00	75
Project	QC	Manufacturing QC	4	16.00	64
Project	Commissioning	Commissioning - DCS	5	12.60	63
Project	EPC	EPC Experience	5	12.60	63
Project	Engr	Plant Quality	3	18.33	55
Project	Commissioning	Commissioning - PB	4	13.50	54
Project	EPC	EPC Qualified Labor	4	13.50	54
Project	Engr	Equipment reliability	2	25.00	50
Project	Commissioning	QA/QC	3	15.00	45
Project	EPC	EPC Contract	3	15.00	45
Project	EPC	EPC Logistics	3	15.00	45
Project	Commissioning	Schedule	3	13.00	39
Project	EPC	EPC QC	3	13.00	39
Project	Engr	Emergency Power	2	15.00	30
Project	EPC	EPC Communications	2	15.00	30
Project	Engr	Control Room	3	9.00	27
Project	Engr	Specifications - HX	3	9.00	27
Project	Engr	Design review/approval	1	25.00	25
Project	Commissioning	Documentation	2	12.00	24
Project	EPC	Equipment reliability	2	12.00	24
Project	QC	Construction Supervision	2	12.00	24

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Category	Subcategory	Issue Type	Count	Priority	Weight
Project	Commissioning	Commissioning - Solar Field	2	9.00	18
Project	Engr	Schedule	1	15.00	15
Project	Engr	Solar Resource Assessment	1	15.00	15
Project	Engr	O&M Participation	1	15.00	15
Project	EPC	Procurement	1	15.00	15
Project	EPC	Performance Guarantee	1	9.00	9

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Table C-5. O&M Issues in Rank Order

Category	Subcategory	Issue Type	Count	Priority	Weight
Project	O&M	O&M Staff Quality	10	15.40	154
Project	O&M	O&M Training	8	16.00	128
Project	O&M	O&M Labor Costs	7	14.14	99
Project	O&M	Water Chemistry	5	19.00	95
Project	O&M	O&M Provider Quality	8	11.00	88
Project	O&M	Service Groups	6	14.67	88
Project	O&M	O&M Costs	6	14.00	84
Project	O&M	Spare Parts	5	14.60	73
Project	O&M	O&M Systems	5	13.40	67
Project	O&M	O&M Procedures	4	14.50	58
Project	O&M	Equipment reliability	3	13.00	39
Project	O&M	O&M Integration	1	25.00	25
Project	O&M	Outages - Planned	2	10.00	20
Project	O&M	DNI Forecast	1	15.00	15
Project	O&M	Reflectivity Monitoring	1	9.00	9
Project	O&M	Water Discharge	1	3.00	3

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