WATEREUSE

Evaluation of Natural Gas to Reduce Carbon Footprint and Energy Costs for Desalination

WateReuse Research Foundation

Evaluation of Natural Gas to Reduce Carbon Footprint and Energy Costs for Desalination

About the WateReuse Research Foundation

The mission of the WateReuse Research Foundation is to conduct and promote applied research on the reclamation, recycling, reuse, and desalination of water. The Foundation's research advances the science of water reuse and supports communities across the United States and abroad in their efforts to create new sources of high quality water for various uses through reclamation, recycling, reuse, and desalination while protecting public health and the environment.

The Foundation sponsors research on all aspects of water reuse, including emerging chemical contaminants, microbiological agents, treatment technologies, reduction of energy requirements, concentrate management and desalination, public perception and acceptance, economics, and marketing. The Foundation's research informs the public of the safety of reclaimed water and provides water professionals with the tools and knowledge to meet their commitment of providing a reliable, safe product for its intended use.

The Foundation's funding partners include the supporters of the California Direct Potable Reuse Initiative, Water Services Association of Australia, Pentair Foundation, and Bureau of Reclamation. Funding is also provided by the Foundation's subscribers, water and wastewater agencies, and other interested organizations.

Evaluation of Natural Gas to Reduce Carbon Footprint and Energy Costs for Desalination

Mohammad Badruzzaman, PhD, PE, BCEE
MWH

Carla Cherchi, PhD
MWH

Joseph G. Jacangelo, PhD
MWH

Larry Baker
Power Engineers

WATEREUSE

WateReuse Research Foundation
Alexandria, VA

Disclaimer

This report was sponsored by the WateReuse Research Foundation. The Foundation, its Board Members, and the project cosponsors assume no responsibility for the content of this publication or for the opinions or statements of facts expressed in the report. The mention of trade names of commercial products does not represent or imply the approval or endorsement of the WateReuse Research Foundation, its Board Members, or the cosponsors. This report is published solely for informational purposes.

For more information, contact:

WateReuse Research Foundation
1199 North Fairfax Street, Suite 410
Alexandria, VA 22314
703-548-0880
703-548-5085 (fax)
www.WateReuse.org/Foundation

WateReuse Research Foundation Project Number: 13-05

ISBN: 978-1-941242-35-3

Contents

Figures

Tables

Acronyms and Abbreviations

BSER	best system of emission reduction
BTU	British thermal units
CARB	California Air Resources Board
CCPP	combined cycle power plant
CHP	combined heat and power
EGU	electric generating unit
EPS	Encina Power Station
FV	future value
GHG	greenhouse gas
HBGS	Huntington Beach Generating Station
HRSG	heat recovery steam generator
HV/MV	high voltage/medium voltage
IFV	intermediate fluid vaporizer
kV	kilovolt
LCC	life cycle cost
LCOE	levelized cost of energy
LHV	lower heating value
LNG	liquefied natural gas
MED	multiple effect distillation
MMBTU	million British thermal units
MSF	multi-stage flash
NG	natural gas
NSPS	new source performance standard
O&M	operations and maintenance
PG&E	Pacific Gas & Electric
PV	present value
RO	reverse osmosis
SCR	selective catalytic reduction
SWRO	seawater reverse osmosis
U.S.	United States
U.S. EPA	United States Environmental Protection Agency
VC	vacuum compression

Foreword

The WateReuse Research Foundation, a nonprofit corporation, sponsors research that advances the science of water reclamation, recycling, reuse, and desalination. The Foundation funds projects that meet the water reuse and desalination research needs of water and wastewater agencies and the public. The goal of the Foundation's research is to ensure that water reuse and desalination projects provide sustainable sources of high-quality water, protect public health, and improve the environment.

An Operating Plan guides the Foundation's research program. Under the plan, a research agenda of high-priority topics is maintained. The agenda is developed in cooperation with the water reuse and desalination communities including water professionals, academics, and Foundation subscribers. The Foundation's research focuses on a broad range of water reuse and desalination research topics including:

- Defining and addressing emerging contaminants, including chemicals and pathogens
- Determining effective and efficient treatment technologies to create "fit for purpose" water
- Understanding public perceptions and increasing acceptance of water reuse
- Enhancing management practices related to direct and indirect potable reuse
- Managing concentrate resulting from desalination and potable reuse operations
- Demonstrating the feasibility and safety of direct potable reuse

The Operating Plan outlines the role of the Foundation's Research Advisory Committee (RAC), Project Advisory Committees (PACs), and Foundation staff. The RAC sets priorities, recommends projects for funding, and provides advice and recommendations on the Foundation's research agenda and other related efforts. PACs are convened for each project to provide technical review and oversight. The Foundation's RAC and PACs consist of experts in their fields and provide the Foundation with an independent review, which ensures the credibility of the Foundation's research results. The Foundation's Project Managers facilitate the efforts of the RAC and PACs and provide overall management of projects.

The objective of this study was to provide a better understanding of the application of natural gas (NG) and liquefied natural gas (LNG) as a potential alternative to grid electricity at seawater reverse osmosis (SWRO) desalination plants. A life cycle analysis was developed to determine the economic and environmental cost-benefits of LNG/NG use for self-generation of power at desalination plants and for the operation of high pressure pumps using gas engines. The life cycle cost of these different power supply alternatives was then compared to that of the grid electricity for a range of SWRO installations (5-100 MGD). A sensitivity analysis was conducted on two conceptual mid-range capacity desalination plants (25 and 50 MGD) to show the impact of variations in electric tariff rate, LNG cost, plant efficiency, and economic parameters on the total life cycle cost of various power supply options.

Douglas Owen
Chair
WateReuse Research Foundation

Melissa Meeker
Executive Director
WateReuse Research Foundation

Acknowledgments

The authors are deeply grateful to the WateReuse Research Foundation for funding this project and providing the technical expertise of the Project Advisory Committee (PAC). This report would not have been possible without the technical input, guidance, and first-hand knowledge obtained from the participating industries and vendors. Their understanding of key project issues greatly enhanced the success of the project. Gratitude is also extended to the following individuals: Terence Lee, Maria Chau, MWH; Erik Hale, Power Engineers, and the Technical Advisory Committee (TAC) for their input and review of project deliverables.

Principal Investigator
Mohammad Badruzzaman, Ph.D., PE, BCEE, *MWH*

Project Team Members
Carla Cherchi, Ph.D., *MWH*
Joseph G. Jacangelo, Ph.D., *MWH*

Technical Advisory Committee
Les E. Shephard, Ph.D., *Texas Sustainable Energy Research Institute*
Michael Price, PE, *MWH*
Rob Reid, PE, *Power Engineers*
Constantino Senon, PE, *MWH*

Project Advisory Committee
Mark Wilf
Manisha Kothari
Chris Bellona

Participating Utilities and Vendors
American Water
Brad Thomson Company
Caterpillar Inc.
Deep Water Desal, LLC
East Bay Municipal Utility District, California
Guadalupe-Blanco River Authority (GBRA), Texas
General Electric
IDE Technology
Mitsubishi Engine North America, Inc.
Otay Water District, California
Sempra Energy, U.S. Gas and Power
Solar Turbines – A Caterpillar Company
TDX Power
Texas Sustainable Energy Research Institute
Wartsila North America, Inc.
West Basin Water District, California

Executive Summary

Traditionally, seawater desalination processes purchase the power required to satisfy their energy demand from the grid, which often have high unit cost and carbon footprint. The availability of an alternative energy source may provide desalination plants with a number of benefits and secure opportunities to reliably meet the increasing energy demand and reduce the associated environmental impact. In recent years, the application of natural gas (NG) and liquefied natural gas (LNG) have been considered as potential alternatives to grid electricity. To date, the application of NG power plants for running seawater desalination plants is mostly located in regions, such as the Middle East, where NG is readily available at a low price. However, the LNG option to power desalination is not widespread in other parts of the world and only available in regions where the pipeline infrastructure option for NG is limited or nonexistent.

As conceptualized in this study, in a desalination plant, NG or LNG can be applied for two major purposes:

- *On-site gas-fired power generation*. NG or LNG is used as the sole fuel for the on-site power generation facility that powers the desalination plant.
- *Hybrid system.* NG or LNG is used as the fuel for the engines that drive high-pressure pump motors in the desalination plant. The remaining energy is provided through the grid connection.

The benefits and challenges of the application of LNG/NG are inherently dependent on its geography-driven abundance, technological and economic issues associated with engines/turbines, storage capabilities, environmental impacts and overall, on the familiarity of utility managers and policy makers of key implementation matrices. Most of the desalination facilities that are currently using NG or LNG as a fuel are co-located with large power generation plants that divert only a small portion of the power generated to the desalination plant. Power generation plants that are solely dedicated to feed the desalination processes are rare. To date, no systematic study has been conducted to evaluate the economic and environmental cost–benefits of LNG/NG powered desalination plant.

Project Purpose

The overall goal of this project is to provide a better understanding of the application of LNG/NG for self-generation of power at desalination plants and/or for the operation of gas-driven engines for large desalination plant pumping. The specific objectives of this project are to:

- Assess the application of LNG/NG at seawater desalination facilities;
- Perform an economic analysis of the application of LNG/NG for power generation at desalination facilities;
- Identify the environmental benefits/impacts of incorporating LNG/NG at desalination facilities;
- Compare the grid electricity and LNG/NG-based power generation based on life cycle cost (LCC) analysis; and
- Develop a conceptual framework for site-specific implementation of a LNG-based power generation facility at a seawater desalination plant.

A tool was also developed in this study that can be used to compare the economic and environmental cost–benefits of LNG/NG power supplies versus grid electricity on a life cycle basis.

Project Approach

This project team developed an Excel-based spreadsheet (LCC Tool) to conduct the cost and GHG emissions comparison among the following power supply alternatives on a life cycle basis:

- On-site gas-fired power generation where NG or LNG is used as the sole fuel for the on-site power generation facility that powers the desalination plant;
- Hybrid systems where NG or LNG is used as the fuel for the engines that drive high-pressure pump motors in the desalination plant. The remaining energy is provided through the grid connection;
- Grid connection as the sole source that powers the desalination plant.

In order to develop the LCC tool, preliminary design and operating criteria associated with the three power supply alternatives for a number of desalination capacity sizes (within 2.5 to 150 MGD range) were developed. The approach used to develop this cost information for the LCC tool development is presented in Figure ES.1.

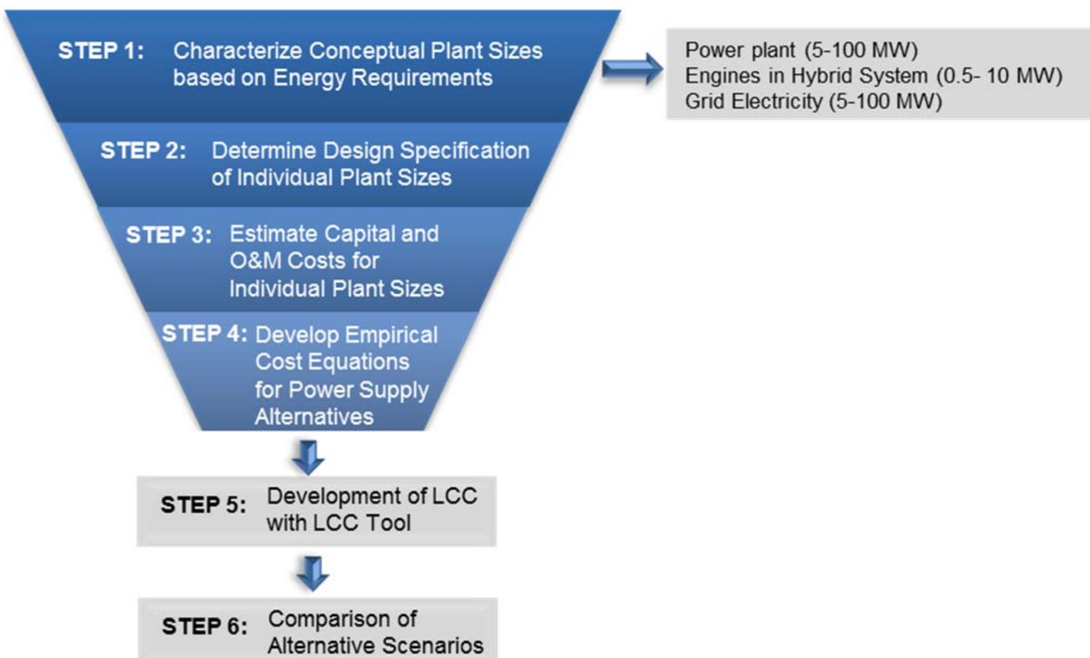


Figure ES.1. Approach used to develop the cost information for the LCC tool.

Design specifications and cost information, which are presented in Chapter 3, were obtained through the following:

- For on-site power generation plants, the software GT PRO (Thermoflow, Inc.) was used as a design tool for combined cycle, cogeneration systems, and simple cycle gas turbine power plants of sizes ranging from 5 to 100 MW. GT PRO is capable of designing such systems by creating a cycle heat balance and identifying the physical equipment needed and cost associated.

- For hybrid systems, design specifications and preliminary and budgetary cost estimates for the engine generator drives with and without heat recovery of using LNG/NG as a fuel for running high-pressure pumps in desalination plants have been provided by different engine manufacturers for sizes between 0.5 and 10 MW.
- For grid connection, design specification and cost estimates were developed by the project team's experience.

The elements of the conceptual design and operating parameters of the gas engines/turbines employed to power desalination plants of various capacities and their related capital and operations and maintenance (O&M) cost information were used to conduct the LCC and life cycle greenhouse gas (GHG) emission comparison between purchasing electricity directly from the power grid and the use of commercially supplied LNG/NG for self-generation of power and/or pumping for desalination processes. The details of the tool and related guidance manual are presented in Chapter 4.

Project Results and Conclusions

This study conducted a conceptual assessment of the comparative economic feasibility and GHG emissions potential of the application of LNG/NG and the electricity provided by the grid supply based on: total costs (capital and O&M costs) in the first year of operation; LCC (capital and O&M LCC); levelized cost of energy; and GHG emissions (first year and life cycle). This comparison was performed for desalination plants of various sizes (from 2.5 to 150 MGD) and two fuel options (NG vs. LNG). The general assumptions used in the analysis are presented in Table ES.1 and the findings and interpretations are valid only for these assumptions. It is also important to note that LCC evaluation is not a financial analysis tool. Once the most attractive option is identified, financial analysis of capital requirement and cash flows takes place, taking into consideration additional factors that are not relevant to economic, or comparative, analysis.

Table ES.1: Assumptions Used for Economic and GHG Emissions Assessment

Parameter	Units	Value
General		
Peaking factor	-	1.5
Power plant efficiency (simple cycle)	%	45
Power plant efficiency (combined cycle)	%	50
High-pressure pump engine efficiency	%	0.45
Life Cycle Assumptions		
Period	Years	25
Initial year of operations	-	2017
Year of analysis	-	2015
Cost Assumptions		
Cost estimate dollar basis year	-	2015
Construction cost escalation	% (Annual)	3.50%
O&M and general cost escalation	% (Annual)	3.00%
Financial Assumptions		
Capital treatment	-	Debt Service
Financing interest rate	%	5.25%
Financing maturity	Years	25
Financing costs, capitalized	%	2.00%
Capitalized interest	%	0.00%
Debt structure	Annual	Equal
Bond reserve	%	0.00%
Economic Assumptions		
Discount rate (cost of capital)	%	5.25%
Annual growth in electricity consumption	%	2.00%
GHG Emission Factors		
LNG/NG emission factor	ton/MMBTU	0.05306
Grid emission factor (PG&E)	tonsCO_2/MWh	0.177
eGrid emission factor (national average)	tonsCO_2/MWh	0.620
Fuel and Electricity Charges Assumptions		
Electricity rates (purchase)	$/kWh	0.08
Demand charge (purchase)	$/kW	10
LNG price	$/MMBTU	8
NG price	$/MMBTU	3

Economic Analysis

On the basis of the conceptual cost analysis on 2.5 to 150 MGD desalination plants, the grid electricity requires lower capital investments than the LNG/NG-based options (on-site /hybrid power generation). Conversely, the grid alternative has higher O&M costs compared to the LNG-based options. Therefore, a LCC-based analysis is needed to understand the true economic benefits of the power supply alternatives.

The size of a desalination plant might be an important factor in the economic assessment of the applicability of grid versus LNG-base power supply. A life cycle analysis was conducted in this study to compare the LCC the different power supply alternatives, as presented in Figure ES.2. For desalination plant size of 20 MGD or higher, the LCC for the grid alternative is higher than both on-site generation and hybrid power supplies. For instance:

- For desalination plants from 20 MGD to 150 MGD the LCC of the on-site power generation option is between 20% and 30% lower than that of the grid connection;
- For plant sizes smaller than 20 MGD, the LCC for the grid option and that of on-site generation are comparable and could be within 5 to 13% difference.

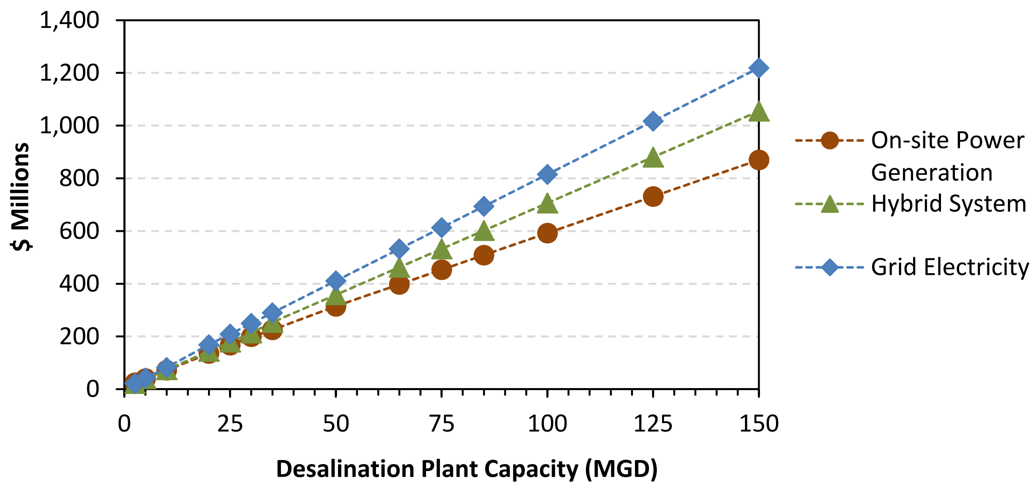


Figure ES.2. Total LCC for an on-site power generation, hybrid system, and grid electricity connection options for desalination plants of various sizes.

The cost of fuel contributes significantly in the economic viability of LNG versus NG, because the market price of LNG is significantly higher than that of pipeline natural gas. In addition to the fuel price, LNG-based power generation systems need the regasification system to revaporize the LNG into gas for use. In this study, the total LCC of the LNG-based on-site power generation and hybrid systems was compared to the NG-based counterpart. In particular:

- For the LNG-based on-site power generation, the total LCC is from 43% to 86% higher than the NG-based counterpart for desalination plants with increasing size from 2.5 MGD to 150 MGD, respectively;
- For LNG-based hybrid systems, the total LCC is 20 to 26% higher than the NG-based counterpart for the same desalination plant sizes.

A sensitivity analysis was conducted to determine the potential impact of a set of parameters on the economics of various power generation options. Two conceptual case studies of mid-range capacity seawater desalination plants of 25 and 50 MGD were selected for this purpose. The results show that variations in electric tariff rate, LNG cost, plant efficiency, and economic parameters, such as the financing interest and discount rates, affect the total LCC of various power supply options. In particular:

- The total LCC of the project is affected by possible variations in the electric tariff rate applied. In particular, by increasing the rate from 8 to 15 cents/kWh, an 85% increase in the total LCC was observed for the grid electricity-based power supply option.
- The total LCC of the project is affected by possible variations in the costs of the LNG. In particular, for on on-site power generation alternative, a 35% increase was observed by increasing the cost of fuel from $8/MMBTU to $12/MMBTU.
- The total LCC of a project is affected by possible variations in the plant efficiency. In particular, a 20% increase in total LCC was obtained by decreasing simple cycle plants' efficiency from the 45% baseline value to 35%. Conversely, about 5% increase in LCC was achieved for combined cycle plants when the efficiency was increased from the baseline 50% to 55%.
- The sensitivity of LCC to the financing interest/ discount rates (e.g., 4%, 5.25%, and 7%) showed that by increasing the financing interest and discount rates from the baseline, a decrease in the total LCC is observed. An increase in the discount rate causes, in fact, a decrease in the present value of the life cycle O&M and, consequently, decreases the total LCC, because the O&M costs represent the majority (i.e., >80%) of the total LCC. For instance, for a 50 MGD desalination plant, a 15% decrease in LCC was achieved when the financing interest/discount rate was increased from the 5.25% to a 7% value.

Levelized Cost of Energy (LCOE) Analysis

An LCOE analysis was also used as a metric to compare the cost of energy generated by the different power generation options. The LCOE represents the cost per kilowatt-hour of building and operating a power generation alternative given an assumed life cycle. The results of the LCOE analysis are presented in Figure ES.3 and in particular:

- For on-site power generation systems, the LCOE decreases from 19 to 11 cents/kWh with increasing size of the desalination plant from 2.5 to 150 MGD;
- For LNG-based hybrid systems, the LCOE decreases from 17 to approximately 14 cents/kWh with increasing size of the desalination plant from 2.5 to 150 MGD; and
- For the grid electricity, the LCOE is slightly affected by the desalination plant size with values between 16 and 17 cents/kWh.

Therefore, the LCOE analysis performed to compare the cost of energy generated by the different power source options showed that for desalination capacities of 10 MGD and higher, the LNG based on-site power generation is the lowest-cost option among all the power supply alternatives evaluated. The hybrid systems also show a lower LCOE than the grid alternative for desalination plants of capacity higher than 5 MGD.

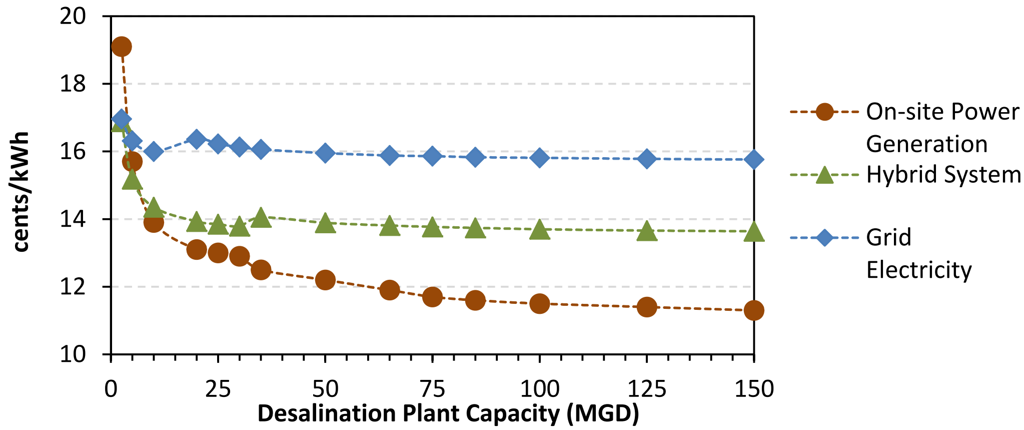


Figure ES.3. Levelized Cost of Energy for the on-site power generation, hybrid system and grid electricity connection options for desalination plants of various sizes.

Environmental Benefit Analysis

GHG emissions arise from electricity usage and from the possible use of alternative fuels. The GHG emission from the grid power supply is sensitive to the energy mix used in the grid and the associated emission factor. On the other hand, the efficiency of the engines/turbine impacts the GHG emission from an on-site power generation facility. The life cycle analysis for the assessment of the GHG emissions showed that when low GHG emission factors are used, such as in some areas in California under the PG&E service area, the grid electricity option resulted in lower life-cycle GHG emissions than those of LNG/NG power source alternatives. For higher emission factors, such those typically established as the U.S. national average by the U.S. EPA, the opposite was observed and the LNG-based on-site power generation appears to be the most sustainable option (Figure ES.4).

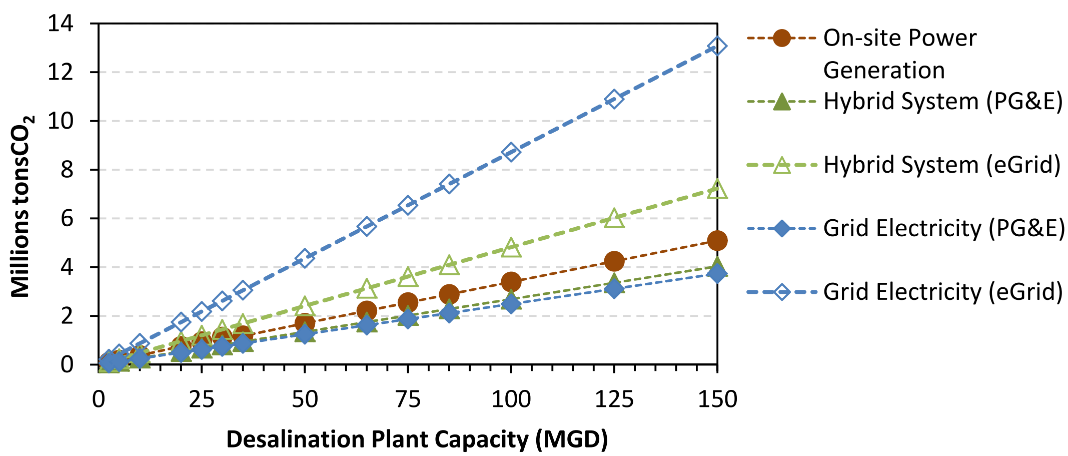


Figure ES.4. Life cycle GHG emissions from the on-site power generation, hybrid system, and grid electricity connection options for desalination plants of various sizes.

The results of the economic and environmental benefit analysis are detailed and discussed in Chapter 5.

It should be noted that the tool developed in this study can be used to compare the economic and environmental cost–benefits of LNG/NG power supplies versus grid electricity on a life cycle basis. The tool does not specifically calculate the energy use breakdown in a seawater reverse osmosis (SWRO) process, rather it compares alternative energy generation processes. For site-specific applications of the tool, it is recommended that the user refines the default values of energy consumption for a SWRO plant currently provided in the tool through independent studies (e.g., modeling, pilot testing).

Chapter 1

Introduction

1.1 Background

Many municipalities and water suppliers are considering seawater desalination to supplement inadequate freshwater sources that are due to increasing water demand, deterioration of the quality of freshwater sources, and the necessity for water supply security (GWI, 2010; Quteishat, 2009). Desalination, along with demand management, is considered the only alternative for water-stressed or arid regions with overdrafted aquifers (Quteishat, 2009).

Global and domestic implementation of desalination technology has risen dramatically in the last 20 years, and as of 2013, the total global desalination capacity is more than 40 million m^3 /day and expected to reach about 100 million m^3/d by 2015 (Ghaffour et al., 2013). This substantial increase was due in large part to advancements in treatment technology that has both improved water quality and reduced production costs. Thus, in some areas, desalination successfully competes with conventional water resources and water transfers for potable water supplies (e.g., construction of dams and reservoirs or canal transfers; Ghaffour et al., 2013). In addition, about 58.9% of desalted water originates from seawater, 21.2% from brackish groundwater sources, with the remaining percentage split among surface water and saline wastewater (Ghaffour et al., 2013).

To date, desalinated water is no longer considered a marginal water resource as some countries, such as Qatar and Kuwait, base their domestic and industrial water provision on desalinated water (Quteishat, 2009). The use of desalination will continue to grow around the world. The majority of large plants have been constructed in the Middle East. In the Mediterranean region, Spain and Algeria are heavily focusing on seawater desalination for economic development. For instance, Algeria is in the process of building seven large desalination plants. In the United States, a number of water districts are already in the planning stages for desalination plants. According to a 2012 report (Cooley and Wilkinson, 2012), 17 seawater desalination plants have been proposed to satisfy 5% to 7% of average urban water demand in California by providing 270 to 390 million gallons per day (MGD) of desalinated water.

Desalination processes, broadly categorized as thermal or membrane-based technologies, are very energy intensive (Greenlee et al., 2009). Although thermal desalination has remained the primary technology of choice in the Middle East, membrane processes, such as reverse osmosis (RO), have rapidly developed since the 1960s (Loeb and Sourirajan, 1963) and currently surpass thermal processes in new plant installations (Greenlee et al., 2009). Of the total water desalted globally, 63.7% is produced by membrane processes and 34.2% by thermal processes. More than 69% of the desalination production capacity in the United States is due to the use of RO membranes, whereas the use of thermal technologies such as MED and MSF is less than 2% combined (Greenlee et al., 2009; Jacangelo et al., 2013). In Southern California, for example, where the desalination market is growing very rapidly, a total of eight desalination facilities serving more than 500 people utilizing RO membrane filtration systems can be found (Rosso and Rajagopalan, 2013).

Thermal desalination processes require both thermal and electrical energy, whereas membrane-based processes need electrical energy only (Quteishat, 2009). The energy intensity (kWh per MG of water treated) of desalination is at least 5 to 7 times the energy intensity of conventional treatment processes, so even though the population served by desalination is only about 3%, it is estimated that approximately 18% of the electricity used in the municipal water industry is for desalination plants. Typically, total energy requirements for RO-based plants are lower than the plants employing other desalination processes, with associated costs for electricity in the range of 28 to 58% of the total cost of desalinated water (WRRF, 2012). Because of the lower energy consumption, RO processes are preferred to thermal-based treatment for domestic water desalinization in the United States. A summary of energy requirements for different desalination processes is presented in Table 1.1.

Table 1.1. Typical Thermal, Electrical, and Total Energy Consumption in Large Desalination Plants

	Thermal Energy (kWh/m^3)	Electrical Energy (kWh/m^3)	Total Energy (kWh/m^3)
Multi-Stage Flash (MSF)	7.5–12	2.5–3.5	10–15.5
Multiple Effect Distillation (MED)	4–7	1.5–2	5.5–9
Vacuum Compression (VC)	-	-	8
Seawater Reverse Osmosis (SWRO)	-	3–6	3–6

For the purpose of this study, the discussion presented herein will cover only the key issues relevant to RO, which is the most common desalination technology used in the United States (Pinzón, 2013). The energy required for desalination using RO membranes is a function of the feed water recovery, intrinsic membrane resistance (permeability), operational flux, feed water salinity and temperature fluctuations, product water quality requirements, and system configuration (Subramani et al., 2011). A theoretical minimum energy is required to exceed the osmotic pressure. This minimum energy increases with increasing salinity of the seawater or feed water recovery. For example, the theoretical minimum energy for seawater desalination with 35,000 mg/L of salt and a feed water recovery of 50% is 1.06 kWh/m^3 (Elimelech and Philip, 2011).

From the analysis of 15 large reverse osmosis (RO) seawater desalination plants that have been constructed since 2005, results showed that on average these plants use about 15,000 kWh per million gallons of water produced (kWh/MG), or 4.0 kWh per cubic meter (kWh/m^3) (Cooley and Heberger, 2013). Typically, the total energy requirement for seawater desalination using RO (including pre- and posttreatment) is on the order of 3 to 6 kWh/m^3, as shown in Table 1.1 (Subramani et al., 2011).

The reverse osmosis process accounts for nearly 70% of the total energy use of the plant, whereas pre- and posttreatment and pumping each account for 13%. Another 7% of energy is used to pump water from the ocean to the plant (Cooley and Heberger, 2013). These percentages might vary from plant to plant depending on several site-specific factors and design of the plant. Design considerations include the desalination technology employed, whether energy recovery devices are used, and the rate of recovery (the volume of freshwater produced per volume of seawater taken into the plant). The recovery rate depends on site-specific factors such as source water salinity and temperature and the desired quality of the product water (Cooley and Heberger, 2013). Figure 1.1 shows an example of how the energy consumption is distributed for different processes and facilities in a seawater desalination plant in California (Loveland, 2015).

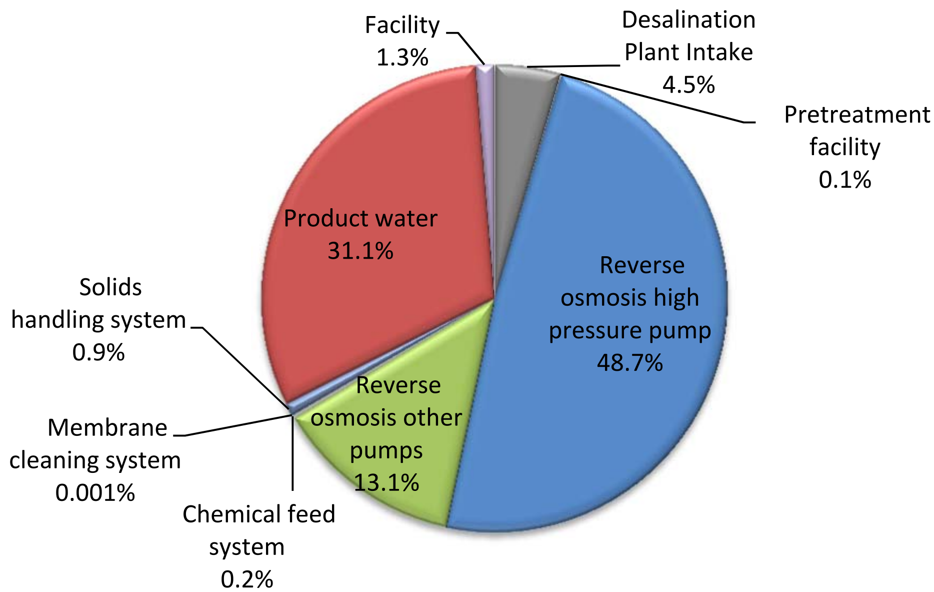


Figure 1.1. Breakdown of percentages of energy consumed at RO-based seawater desalination plant in California.

Source: Loveland, 2015

1.2 Knowledge Gap and Project Goals

In urban regions, the availability of a diversified portfolio of energy sources may provide desalination utilities with a number of benefits and secure opportunities to reliably meet the increasing energy demand and reduce the associated environmental impact. Traditionally, desalination facilities purchase the power required to satisfy their energy demand from the grid, which often has a high unit cost of power and carbon footprint.

In recent years, applications of natural gas (NG) and liquefied natural gas (LNG) have been considered as a potential alternative to the grid electricity. To date, the application of NG power plants for running seawater desalination plants is mostly located in regions, such as the Middle East, where NG is readily available at a low price. However, the LNG option to power desalination is not widespread in other parts of the world and only available in regions, such as Singapore, where the pipeline infrastructure for the NG option is limited or nonexistent.

As availability of NG and LNG is continuously growing in the United States and other parts of the world, LNG/NG-powered desalination could be a feasible alternative to energy from an electrical grid. However, to date, no systematic study has been conducted to identify the parameters impacting the economics of LNG power plants solely designed to operate a desalination plant. The benefits and challenges of the application of LNG is inherently dependent on its geography-driven abundance, technological and economic scale-up issues associated with engines/turbines, maturity of the technology, storage and transmission capabilities, environmental impacts and overall, on the familiarity of utility managers and policy makers with key implementation matrices.

The overall goal of this project is to provide a better understanding of the application of LNG/NG for self-generation of power at desalination plants and/or for the operation of gas-driven engines for large desalination plant pumping. The specific objectives of this project are:

- Assess the application of LNG/NG at seawater desalination facilities;
- Perform an economic analysis of the application of LNG/NG for power generation at desalination facilities;
- Identify the environmental benefits/impacts of incorporating LNG/NG at desalination facilities;
- Compare the grid electricity and LNG/NG-based power generation based on LCC analysis;
- Develop a conceptual framework for site-specific implementation of a LNG-based power generation facility at a seawater desalination plant.

A tool was also developed in this study that can be used to compare the economic and environmental cost–benefits of LNG/NG power supplies versus grid electricity on a life cycle basis.

1.3 Organization of the Report

This report is organized into the following chapters:

- **Chapter 1**: Introduction
- **Chapter 2**: Natural Gas/Liquefied Natural Gas: An Alternative Power Supply for Seawater Desalination
- **Chapter 3**: Technologies for LNG and Grid Power Supply: Design Configuration and Cost Curve Development
- **Chapter** 4: Software Tool for Comparative Analysis of LNG Versus Grid Power Supply: Principles and Guidance Manual
- **Chapter 5**: Economic and Environmental Evaluation of LNG Versus Grid Electricity: Conceptual Case Studies and Sensitivity Analysis
- **Chapter 6**: Conclusions and Recommendations

Chapter 2

Liquefied Natural Gas/Natural Gas: An Alternative Power Supply for Seawater Desalination

To meet the increasing energy demand and to diversify their energy sources portfolios, desalination plants have started looking into the application of LNG and NG as a potential alternative energy sources. This section provides a brief summary of the drivers for the application of power supply alternatives for desalination, with particular focus on the application of LNG and NG for seawater desalination. Selected existing and proposed desalination plants powered by NG or LNG are presented here as case studies.

2.1 Drivers for the Application of LNG/NG for Desalination

The availability of a diversified portfolio of energy sources from that traditionally provided by the grid electricity may provide desalination utilities with a number of benefits and secure opportunities in relation to:

- Power supply availability (e.g., availability in remote areas)
- Economic benefits
- Environmental benefits (e.g., GHG emission reduction)
- Other nontangible benefits (e.g., reliability, resiliency, long-term contracts)

2.1.1. Power Supply Availability

Many countries have now become vulnerable to a future global energy crisis as conventional fossil fuels have become increasingly limited (Ghaffour et al., 2015). The peak production of oil has been already exceeded and by 2030 its exploitation is forecasted to be halved from its 2010 value (Ghaffour et al., 2015). To meet the increasing energy demand, desalination utilities are looking for alternative energy sources, including NG and renewable energy options, primarily solar and wind. The development and use of nonconventional fossil fuel resources, such as shale gas, is believed to cover the electricity demand for some decades and more (Ghaffour et al., 2015). Thus, in recent years, the application of NG and LNG has been considered as a potential alternative to meet this demand.

NG is a nonconventional fossil fuel present in reservoirs in the subsurface. Once extracted, NG can be stored in underground caverns or as LNG in atmospheric tanks. To obtain LNG, NG is condensed to a liquid at -256 ^{o}F and stored at atmospheric pressure. During the liquefaction process, NG volume is reduced by 600 times, making LNG more economical to store and transport than NG. Liquefaction, in fact, provides the opportunities to store NG to meet peak demand electricity periods and to be transported over long distances in places where pipelines networks are not developed (CEE, 2012). Large reserves of NG have been found, in fact, in areas for which there is no significant local market. In this context, LNG offers greater trade flexibility than pipeline transport, allowing cargoes of NG to be delivered where the need is greatest and the commercial terms are most competitive (CEE, 2012). Worldwide, there are 23 LNG export/liquefaction terminals, 50 import/regasification terminals and 224 LNG ships handling 142 million metric tons of LNG each year (CEE, 2012). The United States has the largest number of facilities in the word, with 131 active marine terminals, storage facilities, and operations, particularly concentrated in the Northeastern region (CEE, 2012). Thus, LNG technology makes NG available throughout the world. The analysis on the use, benefits, and challenges of NG and LNG for desalination is one of the main objectives of this study and is detailed in the following sections.

2.1.2. Economic Benefits

One of the major factors influencing the cost of desalination, and thus the total cost of water production, is the energy cost. The energy cost of a desalination plant approximately represents 30 to 44% of the total cost of the related water produced, and these costs are prone to vary significantly during a project's lifetime (Semiat, 2008). Currently, desalination projects based on renewable energy are more costly than those based on conventional energy and require some level of strategic intervention to be a competitive option (World Bank, 2012).

According to Tenne (2010), NG power generation is approximately 7 to 8% less costly than the energy provided by the national (coal-driven) power system in Israel. The U.S. Energy Information Administration (EIA) forecasted that NG will continue increasing as a share of overall U.S. energy production in the coming decades because of the continued expectation that the cost of NG will remain low (Pinzon, 2013). The cost of NG, and consequently that of LNG, has declined over the last couple of years, primarily because of increased domestic production, making NG a feasible economic choice compared to other fuels. Figure 2.1 shows the evolution of the LNG price forecast for the next 15 years. U.S. LNG prices have been quoted as low as 115% x Henry Hub (HH) + $3.00 - $3.50/ MMBTU tolling fee (Sabine Pass – Gulf Coast) to as high as $8 - 10/MMBTU for non-Gulf Coast small-scale facilities. These prices do not include LNG transportation costs, which will depend on geographical market and distances.

This reduction in NG and LNG costs might help reduce the cost of desalinated water production. However, more studies are needed to properly understand the site-specific economic benefits and challenges associated with the application of NG and LNG. In addition, most of the economic information reported for different power supply options at existing or proposed desalination applications are based on the first year present cost value. Because energy cost represents 30 to 40% of the water production cost, LCC analyses are warranted as a better evaluation method to select the most economical power supply alternative for desalination projects.

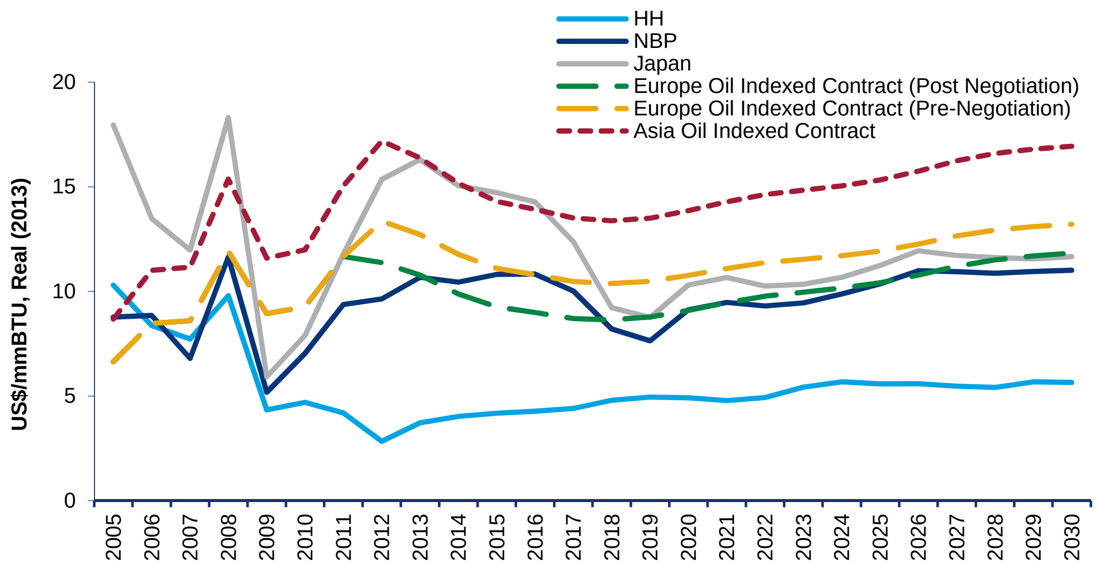


Figure 2.1. LNG price forecast.

Note: HH is the U.S. NYMEX Gas Price at Henry Hub; NBP is the UK gas price. Other prices in this graph are LNG prices in various world markets.

Source: Sempra Energy, 2015

2.1.3. Environmental Benefits

The high energy requirements of desalination are raising concerns about the associated emission of air pollutants and greenhouse gases. In particular, the grid electricity as a power supply option often relies on the use of conventional fossil fuel resources, known to be responsible for significant GHG emissions (Ghaffour et al., 2015). For an RO system used to desalinate seawater with traditional fossil fuel-based energy sources, CO_2 emissions of 1.78 kg/m3 and NOx emissions of 4.05 g/m3 of desalted water have been reported (Raluy et al., 2005; Subramani et al., 2011). In California, the proposed 514 MGD seawater desalination capacity is estimated to increase energy use by about 2,800 GWh per year with related GHG emissions of about 1.0 $MMTCO_{2e}$ annually, assuming that all of the desalination plants are powered by the electricity grid (Cooley and Heberger, 2013). The additional desalination processes would represent about a 1% increase above current electricity use and a 0.2% increase in California's current emissions (Cooley and Heberger, 2013).

In evaluating alternatives to fossil fuels, the U.S. EPA reported that burning NG for electricity generation results in lower quantities of nitrogen oxides, carbon dioxide, and methane emissions, with the latter two being greenhouse gases (API, 2013). Moreover, the 2011 U.S. GHG Inventory estimates that the contribution of methane from LNG operations represents 1.3% of methane emissions from all the segments that make up the NG systems. From an environmental perspective, in fact, NG has the lowest carbon content and GHG emissions of all combustible fuels.

According to Tenne (2010), NG power generation produces only 20% of the CO_2 emissions generated by coal power plants in Israel. When used to reduce peak electric demand, NG may help the local utilities to shut down old, inefficient, polluting power plants that have already exceeded their useful lives. In addition to being a lower carbon intensity fuel, NG combustion technology has become substantially more efficient over the years. In 2011, the CEC reported that the efficiency gain in California's gas-fired power plant fleet since 2001 was more than 24% (CEC, 2012).

The liquefied option of NG is cleaner because all higher hydrocarbons ($C6^+$), inert components (N_2 and CO_2), and most impurities are removed. LNG has also higher Wobbe Index—the measure of the amount of energy delivered to a burner via an injector—than the pipeline NG, making it a more sustainable alternative to fossil fuels and to the same NG alternative to power desalination plants.

New regulations and cap- and-trade programs have been promulgated in the United States and other parts of the world to achieve GHG emissions reduction. In cap-and-trade programs the reduction in emissions is achieved by placing a cap on the amount of emissions and reducing that cap amount over time. These limits are coupled with corresponding allowances given to individual sources of emissions, which can trade the excess allowance to a different emission source when an emissions source does not emit as much GHG as its allowance. The California Air Resources Board (CARB) has designed a cap-and-trade program that is enforceable and meets the requirements of the Assembly Bill 32 (AB 32) —AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020— and expected to cover 85% of the state's GHG emissions (CARB, 2012). Although desalination utilities are currently not qualified to participate in the cap-and-trade program, any change in future regulation may result in revenue streams that could potentially be used to finance capital improvements, reduce utility rates, or for any other purpose the utility deems appropriate.

2.1.4. Other Intangible Benefits

Contracts play an important role in the electricity and NG industry and legally bind two parties to an agreement and allocate their risks (Bachrach, 2002). The pros and cons of different contract terms between NG supply and grid electricity such as long-term contracts, a spot market, or short-term contracts should be carefully evaluated. The risks related to LNG price can be minimized by long-term supply contracts (20–25 years in duration), with a "take or pay" clause that obligates the seller to provide gas at a certain price regardless of market demand.

The NG supply has very different structures as well as planning and operating practices from those of the electricity grid. For example, NG transportation is centralized and typically market driven compared to the more centralized, reliability-driven electric transmission development mechanisms. The planning process for a new NG pipeline and storage infrastructure is typically extended on a larger time-scale than those of electricity.

To date, the application of NG power plants for running seawater desalination plants is increasing, however most are located in regions, such as the Middle East, where NG is readily available at a low price. The LNG option, however, is only available in regions, such as Singapore, where the pipeline infrastructure option is limited or nonexistent.

2.2. NG or LNG for Co-located Power Generation at Desalination Plants

Typically, in a desalination plant, NG or LNG can be applied for two major purposes:

- As a fuel for an on-site power generation facility that powers the desalination plant; or
- As a fuel for the engines that drive high-pressure pump motors.

On-site power generation facilities are usually based on cogeneration and combined cycle applications. In order to understand the site-specific benefits of using LNG/NG as a fuel for on-site power generation the following three scenarios need to be evaluated:

- *On-site gas-fired power generation*. NG or LNG is used as the sole fuel for the on-site power generation facility that powers the desalination plant.
- *Hybrid system.* NG or LNG is used as the fuel for the engines that drive high-pressure pump motors in the desalination plant. The remaining energy is provided through the grid connection.
- *Grid Electricity*. The grid connection is the sole source that powers the desalination plant.

The application of piped NG for running pumps is also not uncommon, as the oil and gas industry commonly uses gas engines to drive pumps and compressors. Some of the water utilities also use gas engines/turbines to operate large raw water/distribution pumps, particularly for shaving the electric load from peak demand periods.

Co-location of desalination plants with power generation plants may improve the economics of desalination, offer cost-reduction advantages to water production and reduce the environmental impact of a desalination plant concentrate (Callahan, 2015). The first concept of a co-located desalination plant was implemented for the Tampa Bay Seawater Desalination Project by Poseidon Resources, who pioneered other implementations worldwide (Voutchkov, 2015).

A desalination process produces two streams: a low salinity permeate, which in turn is conveyed for potable water uses, and a concentrate with salinity levels typically two times higher than the source seawater. A seawater desalination co-located with a power plant reuses the post condenser cooling water from the once-through cooled power generating station as a source of seawater for the desalination plant. In addition, the concentrate generated by the desalination process can be returned and blended with the power plant's cooling water discharge outfall, thus mitigating the localized impact of an undiluted concentrate discharge rich in salinity (Callahan, 2015).

According to Callahan (2015), the advantages of co-locating the desalination plant with a power generating station include:

- *Reliability*. The provision of a dedicated power plant offers protection from daily or seasonal demand fluctuations, guarantees operational reliability, and reduces energy costs, as it potentially avoids power grid connection charges and power tariff fees.
- *Sharing Intake Infrastructures*. Using the existing power plant intake facilities to tap the seawater supply for the desalination facility can significantly reduce desalination construction costs, given that new surface water intake for a desalination plant are typically 5 to 20% of total plant construction costs. In addition, the related environmental impact of a new infrastructure at the seashore can be avoided.
- *Sharing Discharge Infrastructures*. In a co-located configuration, the power plant discharge is used as an intake and discharge to the desalination plant. This configuration might save 5 to 20% in additional infrastructure and could attenuate salinity and thermal discharges from the power plant and desalination effluent, respectively.
- *Increased Temperature of Source Water to Desalination*. Cooling water discharged from the condensers typically is 5 to 15 °C warmer than the source ocean water (Voutchkov, 2015). Warmer water temperatures feeding the RO reduce the electric power consumption on a unit production basis; however, they may enhance materials corrosion and biologic fouling.

- *Limited Intake Permitting*. Using a seawater supply for the desalination facility from the post condenser side of the power generating station's seawater cooling water circulation system can eliminate the need for permitting a new seawater supply intake.
- *Reduced Salinity of Concentrate Discharge Permitting*. Blending the power station's cooling water circulation system discharge, which has the same salinity of seawater, with the concentrate before final discharge can significantly reduce the level of permitting a new seawater concentrate discharge.

Considering these benefits, a growing number of seawater desalination plants are being built in integration with large power generation facilities.

2.3. Selected Desalination Plants Powered by NG or LNG

Several desalination plants worldwide use NG or LNG as a main source of power supply and are mostly located in regions, such as the Middle East, where the cost of NG is inexpensive. The desalination plants in the Middle East are mostly thermal-based, highly energy intensive processes, however, RO-based desalination is the most feasible alternative considered so far for the United States' scenario. In addition, these desalination plants typically do not have dedicated power generation systems; they feed from larger (>500 MW) local NG power plants. The construction of large size power plants is, in fact, typically more economical than plants with smaller capacity.

Table 2.1 presents the location and status of implementation/operation of selected desalination plants worldwide utilizing LNG/NG power sources. Four of these desalination plants coupled with LNG/NG power plants were selected as case studies to provide examples of existing and proposed applications around the world. The selected case studies are highlighted in Table 2.1, and a brief summary on their desalination and power plants is presented in the following sections. Those selected include desalination plants currently in operation (Ashkelon and Tuaspring) and desalination plants not yet constructed where the LNG/NG alternative has been evaluated during the feasibility study (Carlsbad and Huntington Beach). These summary sections review the general features of the desalination process, their power supply practices, highlighting some of the benefits and challenges encountered during implementation of their LNG/NG supply. In addition, the resources needed to construct, maintain, and operate LNG/NG power plants coupled with desalination are also identified and emphasized.

Table 2.1 Selected Desalination Plants Coupled with LNG/NG Power Plants

Facility	Location	Desalination Plant Capacity (m^3/day)	Power Plant Size (MW)	Status
Al Taweelah-A1	Abu Dhabi, United Arab Emirates	385,000	1,430	In operation
Al Taweelah-A2	Abu Dhabi, United Arab Emirates	230,000	710	In operation
Al Taweelah-B	Abu Dhabi, United Arab Emirates	346,000	732	In operation
Aweer-2	Dubai, United Arab Emirates	N/A	600	In operation
Jebel Ali-D Extension	Dubai, United Arab Emirates	582,000	2900	In operation
Jebel Ali-M	Dubai, United Arab Emirates	640,000	2060	In operation
Qidfa-1	Fujairah, United Arab Emirates	455,000	861	In operation
Qidfa-F2	Fujairah, United Arab Emirates	590,000	2,160	In operation
Shuweihat S1	Abu Dhabi, United Arab Emirates	378,000	1500	In operation
Shuweihat S2	Abu Dhabi, United Arab Emirates	500,000	1500	In operation
Umm Al Nar	Abu Dhabi, United Arab Emirates	650,000	1,550	In operation
Ashkelon Seawater Reverse Osmosis*	Israel	350,000	80	In operation
Singapore, Tuaspring*	Singapore	318,500	411	In operation
Guadalupe-Blanco River Authority	Texas, USA	95,000–950,000	500–3,000	Planned
Rosarito Beach Binational Seawater Desalination Plant	Rosarito Beach, Mexico	378,000	N/A	Feasibility Study
Carlsbad Desalination Plant*	California, USA	190,000	588	Feasibility Study
Huntington Beach*	California, USA	190,000	880	Feasibility Study
Marin County Water District Desalination Plant	California, USA	N/A	N/A	Feasibility Study

*Selected as case study.

2.3.1 Full-scale Applications

This section presents a summary of two full-scale applications of desalination plants powered by LNG and NG: the Ashkelon Seawater RO Plant in Israel and the Tuaspring Sea Water Desalination Plant in Singapore.

2.3.1.1. Ashkelon Seawater Reverse Osmosis (SWRO) Plant

The Ashkelon seawater reverse osmosis (SWRO) plant is one of the largest desalination plants in the world satisfying ~13% of the Israel's domestic water demand and 5 to 6% of the country's water needs (Figure 2.3). The plant was built by VID, a special purpose joint-venture company formed by IDE Technologies and a lead partner (50%): Veolia–Vivendi Water (25%) and Dankner-Ellern Infrastructure (25%). The engineer, procure, and construct contractor was a joint venture named OTID, formed by IDE and OTV (Vivendi Group). Israel Chemicals and Delek Group are equal-share partners in IDE technologies. The operation and maintenance of the desalination plant is the responsibility of IDE, the Vivendi Group, and Ellern joint venture. In 2005, the facility began operation at 50% capacity and attained 100% capacity after only 4 months of operation, with daily production of 348,000 m^3/day (Garb, 2008) of desalinated water. The plant was designed to deliver 118 million m^3 of water per year using a three-center model of high-pressure pumps, energy recovery devices, and membrane banks arranged to operate independently and with higher flexibility. The total cost of the project was approximately U.S. $250M.

Details on the co-located desalination plant and power plant are reported in the following sections.

Figure 2.2. Ashkelon Seawater Reverse Osmosis (SWRO) Desalination Plant

Desalination Plant. The process consists of 40,000 membrane desalination units in 32 reverse osmosis treatment trains and facilities for seawater pumping fed by three-plus-one large 5.5 MW high-pressure pumps (Garb, 2008). The desalination system is expected to run at a continuous base load for most of its operation. Briefly, the system comprises three parallel high-density pipes that provide water supply and enhance operational reliability and minimize maintenance. From the pumping station, raw seawater is delivered to the pretreatment facilities through two separate lines to ensure operation at half plant capacity in the event of a blockage or failure in one of the pipelines or static mixers. The chemical dosing pumps at the treatment facility are equipped with real-time flow-rate adjustment. Filtration is performed in two stages, starting with gravity filters containing gravel, quartz sand, and anthracite media. An energy recovery center made up of 40 double work exchanger energy recovery (DWEER) devices, collects pressurized brine from each plant's RO banks and reclaims the energy.

Power Generation Plant. The desalination plant scheme at Ashkelon includes two separate and redundant energy sources: (1) a dedicated gas turbine power station adjacent to the desalination plant fueled by NG sourced by the Yam Tethys reserve and (2) an overhead high voltage line providing supply from the Israeli national grid. Delek Group fully owns the Independent Power Production (IPP) plant that services the Ashkelon water desalination facility. The combined cycle cogeneration power plant has a capacity of around 87 MW, and provides the majority of its capacity to the desalination plant; the remaining capacity is sold to private customers and the Israel Electricity Company. The power plant is operated by Delek Ashkelon Ltd. The Ashkelon plant has a contractual specific energy of 3.9 kWh/m^3, and 10 to 15% actual performance lower than this target (Garb, 2008). Approximately 10% of the overall plant energy is required by the boron polishing system, installed to limit reproductive and developmental toxicity in animals and damage to sensitive crops in the region.

Details on the power plant equipment and performance are reported in Table 2.2.

Table 2.2. Equipment of Power Plant at Ashkelon, Israel

Equipment	**Model/Details**
Gas Turbines	GE LM2500 + HSPT Low NOx
Gas turbine capacity	80 MW
HRSG	IST once through with dry run option
Steam Turbine	Siemens NK 50/90
Fuel	Natural Gas (Yam Tethys reserve)
Pumps	5.5MW HP pumps (8)
Overhead line	161 kV
Max nominal electrical consumption	< 3.9 kWh/m^3
Power Output	83.5 MW
Efficiency	52%

2.3.1.2. Tuaspring Sea Water Desalination Plant, Singapore.

Tuaspring in Singapore is the largest municipal desalination plant co-located with a power plant in Southeast Asia (Figure 2.4). The seawater desalination and the combined cycle power plant projects in Singapore have been developed by Hyflux on a design, build, own and operate basis. The seawater reverse osmosis desalination plant supplies Singapore with 318,500 m^3 of desalinated water (Hurn and Hagedorn, 2012).

Figure 2.3. Tuaspring Sea Water Desalination Plant, Singapore.

Desalination Plant. The Tuaspring facility uses a combined water system serving both the power plant and the desalination unit. Water is drawn from the sea and first routed to the power plant where it is used as cooling water to condense the steam in the condenser and to cool auxiliary services. As a result, the temperature of the cooling water, which is then fed directly into the desalination plant, rises. The plant uses Hyflux's proprietary Kristal ultrafiltration (UF) membrane technology for the pretreatment process. Kristal UF membranes are designed and developed to effectively remove suspended solids, microorganisms, and bacteria from raw water and extend the lifespan of the downstream RO membranes, thereby consuming less chemicals and energy. The pretreatment is followed by a double pass reverse osmosis (RO) system to produce water for domestic and industrial use. The seawater entering the RO system has high temperature, thus saving a significant amount of energy on the RO pump operation.

Power Generation Plant. A high efficiency 411 MW nameplate-capacity CCPP (Siemens) supplies power to the SWRO desalination plant, with excess electricity being sold to Singapore's electricity market (Hurn and Hagedorn, 2012). Piped NG is currently imported from Malaysia and Indonesia and used as an alternative fuel source in Singapore. A LNG terminal started operation in 2013 and provides LNG as a primary fuel to the CCPP incorporated into the Tuaspring desalination plant. The high efficiency Siemens F Class CCPP was selected to provide electricity for the SWRO plant as well as to the Singapore electricity market. Siemens manages the power plant technology and supplied a SGT5-4000F gas turbine, the HRSG (heat recovery steam generator), a SST5-3000 steam turbine, a SGen5-2000H-series hydrogen-cooled generator, and the SPPA-T3000 instrumentation and control system, as well as some other systems.

Details on the power plant equipment and performance at Tuaspring are reported in Table 2.3.

Table 2.3. Equipment of Power Plant at Tuaspring, Singapore

Equipment	Model/Details
Gas Turbines	SGT5-4000F (single-shaft)
HRSG	Triple pressure
Generator	Hydrogen cooled generator SGen5-2000H for the steam and gas turbine
Steam Turbine	SST5-3000 with axially installed condenser, coupled to the generator by Syncro-Self-Shifting clutch (SSS)
Fuel	Natural gas (re-gasified LNG)
Plant Control System	SPPA-T3000
Overhead line	230 kV
Power Output	> 390 MW
Efficiency	58.5 %

2.3.2 Proposed Applications

This section presents a summary of two proposed desalination plants that will be utilizing NG fuel—the Huntington Beach Desalination Plant (Poseidon) in California and the Carlsbad Desalination Plant, California.

2.3.2.1. Huntington Beach Desalination Plant (Poseidon), California

Poseidon has proposed the development of a 190,000 m^3/d Huntington Beach Desalination plant to be located near the Huntington Beach Generating Station (HBGS) power plant. The approvals for the desalination plant were obtained in June 2013 with commissioning activities expected to start in 2016. The new facility will supply Orange County with about 80% of its total water demand and will serve about 300,000 residents. The plant will provide an alternative water source to the local groundwater basin, Sacramento Delta, and the Colorado River water supplies.

Desalination Plant. The desalination plant will include a seawater intake system, pretreatment facilities, a seawater desalination facility, posttreatment facilities, product water storage tank located above ground, chemical storage tanks, pump stations, and a product water transmission pipeline. The pretreatment filtration system for the plant will be either a single-stage gravity or two-stage gravity media filtration system and will incorporate coagulants and cartridge filtration as part of the final phase of pretreatment. The RO facility will be a single pass membrane system equipped with 12 operational treatment trains and a standby operational treatment train. Feed water will be conveyed using feed pumps, fitted with variable frequency drive systems, at pressures ranging from 800 to 1,000 psi. The produced water from the RO system will be stabilized using lime and carbon dioxide, and will be disinfected using chlorine.

Power Generation Plant. The HBGS is a NG-fired steam electric generating facility located in the city of Huntington Beach, Orange County, owned and operated by AES Huntington Beach, LLC. The HBGS consists of four gas-fired steam turbine generators of 215 MW and 225 MW capacities, with a total capacity of 880 MW. HBGS currently operates four steam generating units. HBGS operates one cooling water intake structure to provide condenser cooling water to all four steam generating units. HBGS withdraws substantially less than its design capacity because of its low generating capacity utilization. When in operation and generating the maximum load, HBGS can be expected to withdraw water from the Pacific Ocean at a rate approaching its maximum capacity. Once-through cooling water is combined with low volume wastes generated by HBGS and discharged through a submerged structure approximately 1,200 feet offshore in the Pacific Ocean. The discharge pipeline of the existing condenser cooling water circulation system at the AES Huntington Beach Generating Station (HBGS) will provide water to the desalination plant. The generating station is currently permitted to circulate up to 514 MGD of seawater for the four generation units' steam condensers.

2.3.2.2. Carlsbad Desalination Plant, California

The Carlsbad Desalination Project, located in San Diego County, CA, at the Encina Power Station (EPS), will provide 190,000 m^3/d of desalinated seawater per day to serve 300,000 residents and provide the County with approximately 7% of its total water supply by 2020.

Desalination Plant. The Carlsbad Desalination Plant will include an intake pump station and pipeline, a concentrate return pipeline, a sewer connection, electrical transmission lines, road improvements, and product water pump station and pipeline. The desalination facility is connected to the discharge channel of the Encina Power Station at two locations. The intake pump station delivers 380,000 m^3/d of seawater to the desalination facility. Source water for the project will come from the once-through non-contact seawater in the existing cooling water system at the Encina Power Station. Approximately 390,000 m^3/d of seawater from the power station condensers will be piped to the desalination facility. The source water will be pretreated and filtered through RO membranes to produce high-quality drinking water. This water will be delivered to Carlsbad and the surrounding communities.

The pumps feeding the 14 RO trains have 8,000 horsepower motors attached and a unique configuration that offers energy savings— energy left from RO filtration will be captured and transferred back to the front of the system. The PX Pressure Exchanger Q300, provided by Energy Recovery Inc., recycles an estimated 116 million kWh/year lost energy in the form of pressure (98 % efficiency) without consuming additional electrical power. By using the energy recovery devices, the plant should save $12 million each year and reduce CO_2 emissions by 41,000 metric tons.

The saline by-product of the RO treatment with twice the salt content of seawater will be diluted with the return flow from the power plant cooling water system prior to discharge to the Pacific Ocean. This ensures that the increased salinity will not impact the marine organisms in the vicinity of the discharge channel. The 190,000 m^3/d of drinking water produced by the desalination plant will be delivered to Poseidon customers in San Diego County by a water conveyance system that consists of a product water pipeline, several booster stations, and other service structures.

Power Generation Plant. The Encina Power Station (EPS) is a large NG and oil-fueled electricity generating plant located in Carlsbad, CA, owned by NRG Energy. NRG announced plans to expand the Encina Power Station with the construction of a new 588 MW plant on a plot of land adjacent to the current site. The power plant intake will withdraw a minimum of 1.2 million m^3/d seawater from the Pacific Ocean via the Aqua Hedionda Lagoon. After passing through the intake structure trash racks and traveling screens, the collected cooling seawater will be pumped through the condensers of the power plant generation units. Approximately 750,000 m^3/d of warm seawater will be discharged from the EPS condensers into a common enclosed discharge channel, which will convey the plant discharge to the Pacific Ocean through a jetty. The Encina Power Plant pumps about 800,000 million gallons of water per day through its condenser and to cool its boilers. Approximately 100 MGD of water leaving the power plant are delivered to the desalination plant to produce 190,000 m^3/d of water to be delivered to customers. The remaining 190,000 m^3/d are pumped out of the desalination plant and diluted with the flow that the power plant is pumping back out into the ocean.

2.4 Knowledge Gaps Identified from Case Studies

A number of knowledge gaps were identified through the in-depth analysis of the literature from which the previous case studies were developed. In particular:

- Most of the examples of desalination facilities that use NG or LNG as a fuel are powered by very large power generation plants that divert only a small portion of the power generated to the desalination plant. Very limited examples can be found on power generation plants that are solely dedicated to feed desalination processes.
- Although many studies are available on the design specifications and performance of desalination plants, limited studies describing the power generation aspect and the integration between the desalination plant and the power plant are publicly available.
- The cost information (with detailed breakdown) on the power generation process fueling these desalination plants is not found in public domain, as this information is mostly the domain of private entities.
- Side-by-side comparisons of different power alternatives for desalination plants based on the LCC are also not available in the literature.
- The majority of the studies describe the use of piped natural gas as widely used fuel for power generation and very limited case studies are focused on LNG applications.

In the next chapters, the current study attempts to fill these knowledge gaps by demonstrating the applicability of LNG at desalination facilities and by providing LCC information of various LNG/NG-based power supply alternatives. The costs of these alternatives are also compared with that of purchasing electricity directly from the power grid.

Chapter 3

Technologies for LNG and Grid Power Supply: Design Configuration and Cost Curve Development

This study led to the development of an Excel-based spreadsheet to conduct the cost and GHG emissions comparison among the following power supply alternatives on a life cycle basis:

- On-site gas-fired power generation where NG or LNG is used as the sole fuel for the on-site power generation facility that powers the desalination plant;
- Hybrid systems where NG or LNG is used as the fuel for the engines that drive high-pressure pump motors in the desalination plant. The remaining energy is provided through the grid connection;
- Grid connection as the sole source that powers the desalination plant.

This section presents the elements of the conceptual design and operating parameters of the gas engines/turbines and grid connection needed to power desalination plants of various capacities (2.5 to 150 MGD) and their related capital and O&M cost information used for the development of the spreadsheet and further integrated into the tool. The approach used to develop this cost information used as a basis for the LCC tool development is presented in Figure 3.1.

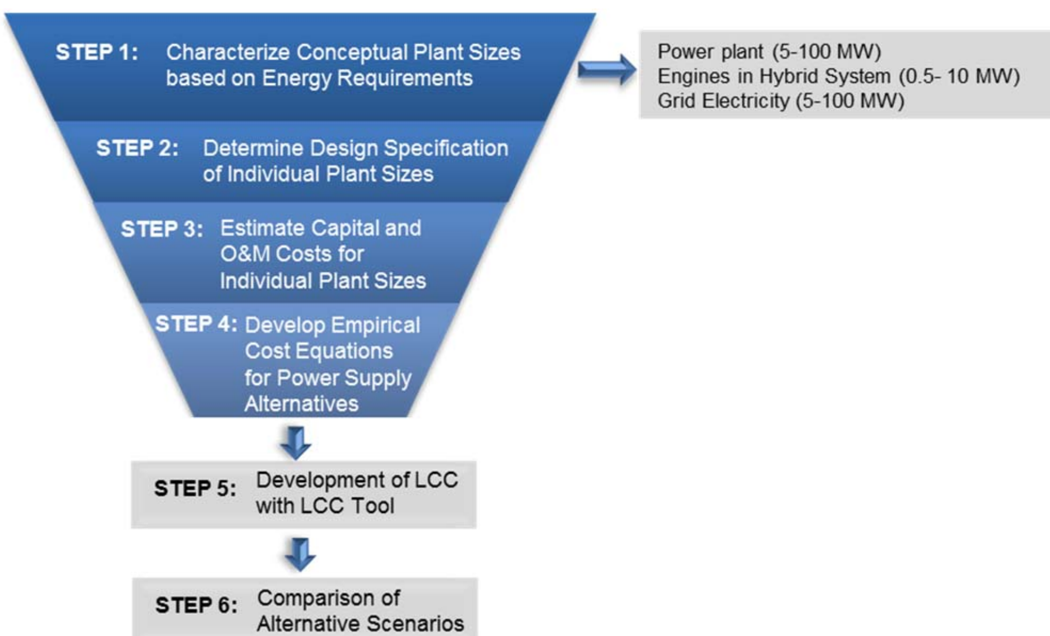


Figure 3.1. Approach used to develop the cost information for the LCC tool.

This Chapter will provide details on Step 1 through Step 4 of the proposed approach. The development of the LCC analysis and the description of LCC tool, part of Step 5, are presented in Chapter 4. Chapter 5 will include the comparative LCC evaluation of all the power supply alternatives included in Step 6.

3.1 On-site Power Generation at Desalination Plants

In LNG/NG-based power generation plants, the intrinsic energy of the fuel is first converted into mechanical work and then transformed into electric power by a generator. Power plants can typically operate in simple cycle or combined cycle modes. Figure 3.2 shows the typical components of a simple cycle and of combined cycle power plants. Typical process components of a LNG simple cycle power generation plant include the regasifier, the prime mover, and generator; whereas in a combined cycle configuration an additional steam cycle is integrated including a heat recovery system, steam turbine, and a generator.

When LNG is selected as the fuel option, regardless of the power plant configuration, a regasification process is needed to regasify the LNG into NG for use by the gas engines or turbines. Among different technologies recently introduced in the market, the intermediate fluid vaporizers (IFVs) are the most commonly used and use an intermediate heat transfer fluid to revaporize LNG in a closed-loop, open-loop, or combination system configuration. The vaporization system utilizes indirect heat by using a heating medium to warm an intermediate (or secondary) medium that transfers the heat to the LNG. A typical intermediate fluid can be propane or water/glycol mixtures and the thermal energy sources can be air or seawater.

In simple cycle NG-fueled power plants, the combustion (gas) turbine is composed of three main sections: the compressor, which draws and pressurizes air into the engine; the combustion system that produces a high temperature, high-pressure gas stream that enters and expands through the turbine section; and the turbine composed of an array of rotating blades that drive the compressor to draw more pressurized air into the combustion section, and spin a generator to produce electricity.

Combine cycle configurations can be used to increase the overall efficiency of electric power plants by recovering and utilizing the residual heat energy in hot exhaust gases. In combined cycle systems a HRSG is employed to captures heat, before it enters the combustion chamber, from high temperature exhaust gases to produce steam, which is then supplied to a steam turbine to generate additional electric power.

The efficiency of electric power generation for combustion turbine systems, operating in a simple-cycle mode, ranges from 21 to 40%. About 50 to 60% efficiency is possible when the turbine exhaust heat is recovered in a heat recovery steam generator to produce steam that can be either used for mechanical/process needs or for generation of additional power in a steam turbine. To make an economical selection of these power generation systems, an understanding of their efficiencies, costs, and the factors impacting these parameters is critical.

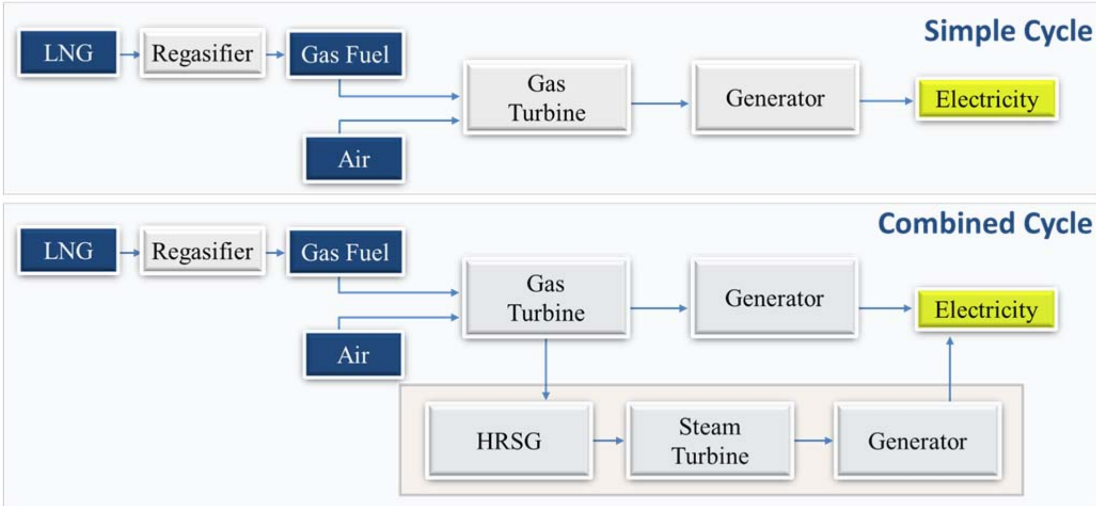


Figure 3.2. Components of a simple cycle (top) and combined cycle (bottom) power generation plant.

3.1.1 Design Specification

On-site LNG power generation plants of 5 to 100 MW size have been considered for developing conceptual designs for 5 to 150 MGD desalination plants. Table 3.1 summarizes the typical process components of a LNG power generation plant, which include the regasifier, prime mover, the heat recovery, the steam turbine, generator, pollution control, and electrical connection.

The selection of the prime movers has been driven by the power generation plant size. From an economic standpoint, the use of engine generators is the preferred option for smaller size plants (5–10 MW); however gas turbines and combined cycle processes are preferred for power generation plants of sizes greater than 20 MW. Gas turbines are typically of two types— frame-based or aeroderivative engines. Frame engines are characterized by lower pressure ratios (<20)—the ratio of the compressor discharge pressure and the inlet air pressure—whereas the aeroderivative engines are derived from jet engines and operate at very high compression ratios (> 30). Frame size gas turbines are found to be better options than the aeroderivative counterparts for plant size greater than 50 MW. Aeroderivative engines are very compact and useful where smaller power outputs are needed. Recently, small size steam turbines of 1 to 2 MW size have been introduced in the market, however the benefits associated to their application in this analysis still needs further investigation.

In combined cycle application, the selection of the steam turbine is such that the ratio between the MW size of a steam turbine and MW required by a gas turbine is maintained as 1:2.

The air emission control systems selected for these plants include a selective catalytic reduction (SCR) unit that removes nitrogen oxides prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The design of SCR is of importance, particularly for large frame turbines with higher power outputs, which can produce larger amounts of emissions, such as NOx.

For this study GT PRO (Thermoflow, Inc.) was used as a software design tool for combined cycle, cogeneration systems, and simple cycle gas turbine power plants. GT PRO can accommodate gas turbines in simple cycle, to engines exhausting into waste heat recovery boilers for process steam, optionally including condensing, noncondensing, or reheat steam turbines, with any sort of cooling system. The software is capable of designing such systems by creating a cycle heat balance and identifying the physical equipment needed.

Table 3.2 summarizes the system configuration and equipment selected for the simulation with GT Pro. Eight different process configurations (e.g., single *vs.* combined cycle, aeroderivatives *vs*. frame-size) were selected, with power outputs included in the range of 5 to 100 MW. In some cases, comparative analysis of simple cycle and combined cycle were made for the same power generation size. For each size, specific engine/turbine manufacturer and models were chosen. It is important to note that the purpose of this task was not to select the best equipment among various models and manufacturers for cost and performance. The goal was to identify, for various power plant sizes, typical components, range of operating performance (e.g., efficiency), and approximate costs. The information collected was used to develop the cost curves that were eventually used for the LCC analysis spreadsheet development, which is presented in detailed in the following sections.

Table 3.1. LNG Power Plants Coupled with Desalination Simulated Using GT PRO Software

Size (MW)	Regasifier	Prime Movers	Heat Recovery	Steam Turbine	Generator	Pollution Control	Electrical Connections
5	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Engine Generator (CAT, Cummins, Kawasaki)	▪ Waste heat from jacket water ▪ Waste heat from exhaust	▪ N/A* ▪ Steam turbines (1-2 MW - Siemens)	▪ Single Engine Generator	SCR	HV/MV Substation
10	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Engine Generator (CAT, Cummins, Wartsila)	▪ Waste heat from jacket water ▪ Waste heat from exhaust	▪ N/A* ▪ Steam turbines (1-2 MW - Siemens)	▪ Single Engine Generator	SCR	HV/MV Substation
20	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Gas Turbine (Aeroderivative) (GE, Solar Gas Turbines, Siemens)	▪ HRSG (Vogt, Nooter Eriksen, Victory)	▪ Steam to process ▪ Steam Turbine* (5-8 MW)	▪ Simple cycle with HRSG ▪ Combined Cycle*	SCR	HV/MV Substation
50	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Gas Turbine (Aeroderivative) (GE, Siemens)	▪ HRSG (Vogt, Nooter Eriksen, Victory)	▪ Steam Turbine (20-30 MW)	▪ Combined Cycle	SCR	HV/MV Substation
75	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Gas Turbine (Frame) (GE, Solar Gas Turbines, Siemens)	▪ HRSG (Vogt, Nooter Eriksen, Victory)	▪ Steam Turbine (30-40 MW)	▪ Combined Cycle	SCR	HV/MV Substation
100	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Gas Turbine (Frame) (LMS100 – GE) (Siemens – SGT6)	▪ HRSG (Vogt, Nooter Eriksen, Victory)	▪ Steam Turbine (40-50 MW)	▪ Combined Cycle	SCR	HV/MV Substation

Note. * Typically not economical

Table 3.2. LNG Turbine and Engines Manufacturers and Models Used in GT PRO Simulations Software

Size (MW)	Configuration	Model	Comments
5	Engine Only	1 x 0 x 0 Kawasaki KG-12V	-
5	Combined Cycle	1 x 1 x 1 Kawasaki KG-12V	-
10	Engine Only	1 x 0 x 0 Wärtsila 20V34SG	-
10	Combined Cycle	1 x 1 x 1 Wärtsila 20V34SG	-
20	CTG + HRSG	1 x 1 x 0 Solar Titan 250	-
20	Combined Cycle	1 x 1 x 1 Solar Titan 130	-
50	Combined Cycle	1 x 1 x 1 GE LM6000 PC	Non-SPRINT-ed and still requires water injection
75	Combined Cycle	1 x 1 x 1 RR Trent 60 WLE	Provided as an aeroderivative based CTG
75	Combined Cycle	1 x 1 x 1 Siemens SGT-800-50	Provided as a frame-based CTG (< 68 MW target)
100	Combined Cycle	1 x 1 x 1 GE 6FA.03	Exceeds target (113 MW)

The design and operating criteria used for the design of LNG on-site power plants are summarized in Table 3.3. Various assumptions were used in the design of various size/configuration power generation plants for use in GT-PRO simulations and the following cost estimations. Some of these assumptions apply to all cases analyzed; others were specific to each power plant. Tables 3.4 and 3.5 report the common and more specific assumptions used for the simulations, respectively. The results from GT-PRO simulations for the design and economic evaluations of various power generation plants configurations and sizes are summarized in the following sections.

Table 3.3. Design and Operating Criteria Used for the Design of LNG On-site Power Plants and HP Pump Running Engines

On-site Power Generation Plants	HP Pump Running Engines
▪ Number and size	▪ Number and size of engines
▪ Electric heat rate	▪ Pump horsepower
▪ Electrical efficiency	▪ Electrical efficiency
▪ Fuel inputs	▪ Fuel inputs
▪ Required gas pressure	▪ Required gas pressure
▪ Exhaust steam flow	▪ Exhaust steam flow
▪ Gas turbine exhaust temperature	▪ Gas turbine exhaust temperature
▪ Steam output	
▪ Total efficiency	
▪ Power/heat ratio	
▪ Net heat rate	

Table 3.4. Assumptions Used for GT Pro Simulations and PEACE Cost Estimates

- Gas analysis is typical pipeline quality NG (~97% methane)
- Gas pressure available: 60 psig (75 psia)
- GT Pro model of gas turbines/engines (no correction to actual vendor data)
- GT Pro specification of gas pressure requirement (may vary from what vendor requires)
- PEACE prices based on GT Pro default cost modifier for California
- Turbine/engines indoors; HRSGs (as necessary) outdoors
- 90% efficiency on SCR catalyst
- Aqueous ammonia at 19% concentration, based on 5 ppm (v/w) slip
- 90% efficiency on CO catalyst
- Electrical transmission per default GT Pro values
- PEACE estimates go up to only high side of the generator step-up transformer (no switchyard costs)
- ISO conditions: 0 feet site elevation, 59 deg F, 60% RH
- No inlet air treatment considered
- One (1) gas compressor per engine/turbine; no spare
- Integral deaerator (or standalone dearator) in HRSG
- HRSG Pinches – 20 deg F on HP/IP, 15 deg F on LP
- HRSG Approach – 10 deg F on HP/IP
- Blowdown – 1%
- Mechanical Draft Cooling Tower – 1.6 in Hg
- No bridge crane
- Default steam conditions in Steam Pro
- Fire protection excluded

Table 3.5. Specific Assumptions Used for GT Pro Simulations and PEACE Cost Estimates for Different Power Generation Plant Sizes and Configurations

Plant	Assumptions
5 MW Single Cycle and Combined Cycle	▪ Kawasaki KG-12V ▪ NOx = 57 ppmvd @ 15% O_2 (per Kawasaki literature) ▪ CO = 100 ppmvd @ 15% O_2 (assumed) ▪ Bottoming Cycle – 1PNRH
10 MW Single Cycle and Combined Cycle	▪ Wartsila 20V34SG ▪ NOx = 95 ppmvd @ 15% O_2 ▪ CO = 100 ppmvd @ 15% O_2 (assumed) ▪ Bottoming Cycle – 1PNRH
20 MW Combined Cycle	▪ Solar Titan 250 ▪ NOx = 15 ppmvd @ 15% O_2 ▪ CO = 50 ppmvd @ 15% O_2 ▪ Bottoming Cycle – 2PNRH
20 MW Cogeneration Plant	▪ Solar Titan 130 ▪ NOx = 15 ppmvd @ 15% O_2 ▪ CO = 50 ppmvd @ 15% O_2 ▪ Process – 165 psia and 380 °F
50 MW Combined Cycle	▪ GE LM6000 PC (non-SPRINTED machine); requires water injection for NOx control ▪ NOx = 25 ppmvd @ 15% O_2 ▪ CO = 100 ppmvd @ 15% O_2 ▪ Bottoming Cycle – 2PNRH
75 MW Combined Cycle - Frame Based CTG (Note: 68 MW net)	▪ Siemens SGT-80 (50 MW) ▪ NOx = 15 ppmvd @ 15% O_2 ▪ CO = 10 ppmvd @ 15% O_2 ▪ Bottoming Cycle – 2PNRH
75 MW Combined Cycle - Aeroderivative CTG	▪ Rolls Royce Trent 60 WLE (non-ISI) ▪ NOx = 25 ppmvd @ 15% O_2 ▪ CO = 75 ppmvd @ 15% O_2 (assumed) ▪ Bottoming Cycle – 2PNRH
100 MW Combined Cycle	▪ GE 6FA.03 ▪ NOx = 15 ppmvd @ 15% O_2 ▪ CO = 9 ppmvd @ 15% O_2 ▪ Bottoming Cycle – 2PNRH

3.1.2 Modeling Power Plant Performance Results

GT Pro simulations were performed to design and develop the cycle heat balance for power generation plants of various sizes. The simulation outputs consisted of combination process, heat, and mass balance, including gross and net electrical outputs, heat rates, and fuel energy inputs for the options previously listed in Table 3.2. Examples of GT Pro outputs, including the significant flows within a 10 MW simple cycle and 100 MW combined cycle power generation plants are presented in Figures 3.3 and 3.4.

The simple cycle combustion turbine differs from a combined cycle operation in that it has only one power cycle without provision for waste heat recovery in the turbine exhaust. The efficiency of electric power generation for combustion turbine systems, operating in a simple-cycle mode is typically lower if compared with those in the combined cycle producing high-quality heat, steam and hot water for other applications. In the two examples proposed, the 10 MW engine was characterized by a LHV electric efficiency at the generator terminal of 45%, much lower if compared to the performance achieved by the 100 MW frame-based combined cycle (54%). Table 3.6 summarizes the performance of various sizes/configurations for power plants that were obtained with GT Pro.

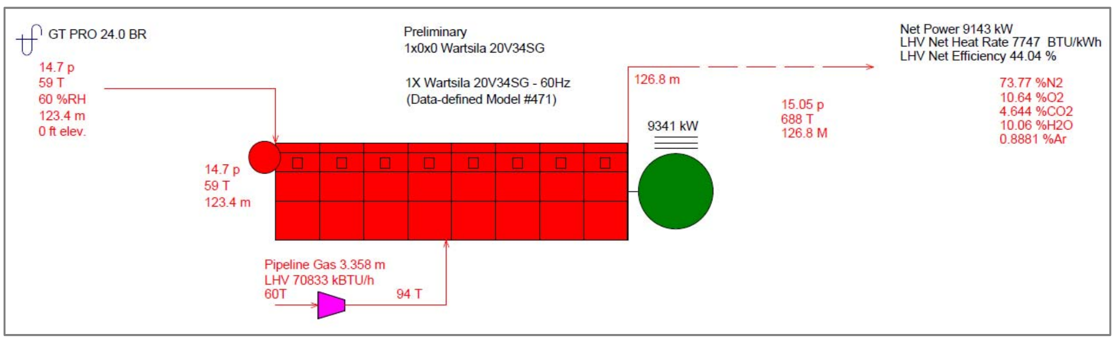


Figure 3.3. Process, heat and mass balance for a simple cycle plant of 10 MW sizes obtained using GT Pro.

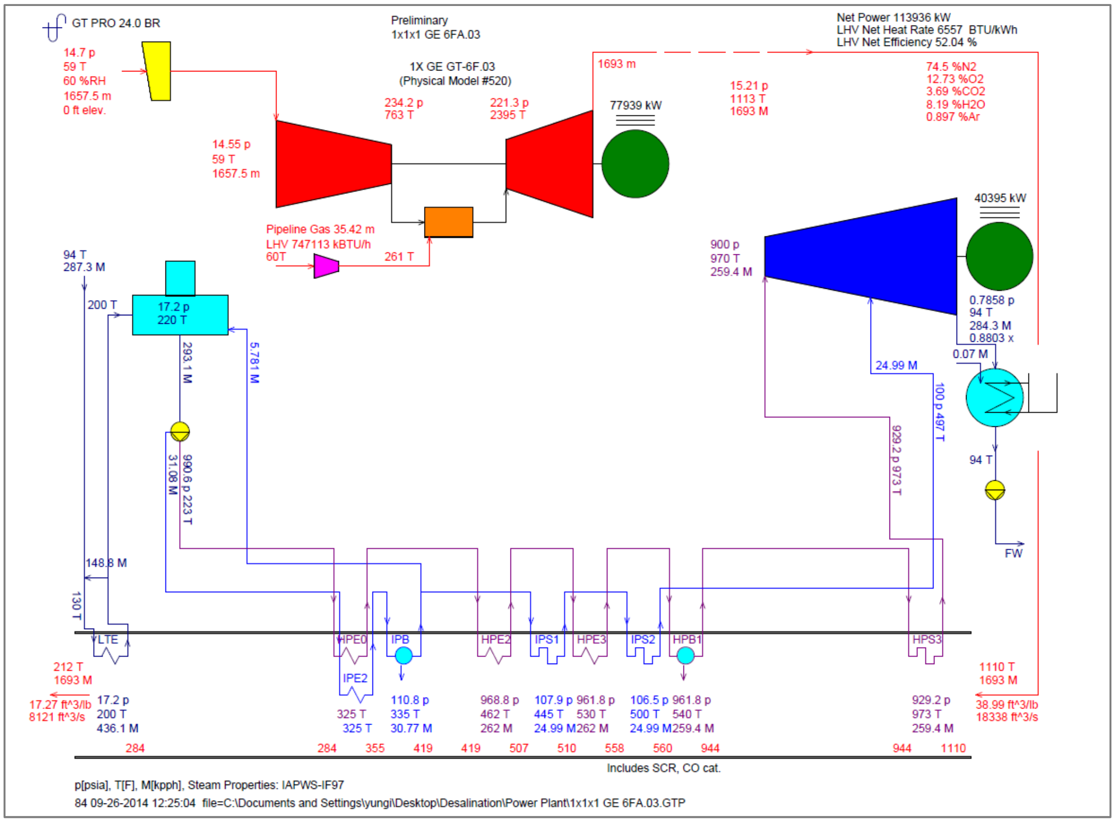


Figure 3.4. Process, heat and mass balance for a combined cycle plant of 100 MW sizes obtained using GT Pro.

Table 3.6. Results from a GT-PRO Analysis for Different Plants and Plant Sizes

		5 MW (ENG)	5 MW (CC)	10 MW (ENG)	10 MW (CC)	20 MW (CGT + HRSG)	20 MW (CC)	50 MW (CC)	75 MW (CC-A)	75 MW (CC-F)	100 MW (CC-F)
Total power output @ generator terminal	kW	5000	5242	9341	10095	21011	20523	55367	78345	71213	118334
Total auxiliaries & transformer losses	kW	107	110	197.9	216.6	1031.7	840.1	2315.5	3413	2796.7	4398
Net power output	kW	4893	5132	9143	9878	19980	19683	53052	74932	68417	113936
LHV heat rate @ generator terminal	BTU/kWh	6917	6605	7583	7017	8930	6980	6685	6538	6251	6314
Net LHV heat rate	BTU/kWh	7068	6746	7747	7171	9391	7278	6977	6836	6507	6557
LHV electric efficiency @ generator terminal	%	49.34	51.67	45	48.63	38.21	48.88	51.04	52.19	54.59	54.05
Net LHV electric efficiency	%	48.28	50.58	44.04	47.59	36.33	46.88	48.91	49.92	52.44	52.04

From the analysis of the gross heat rates that characterized the combined cycle power generation plants of various sizes between 5 and 100 MW, it is evident that by increasing the plant size the LHV heat rate decreases. The LHV and efficiencies were built into the calculation of GHG emissions from the power plants.

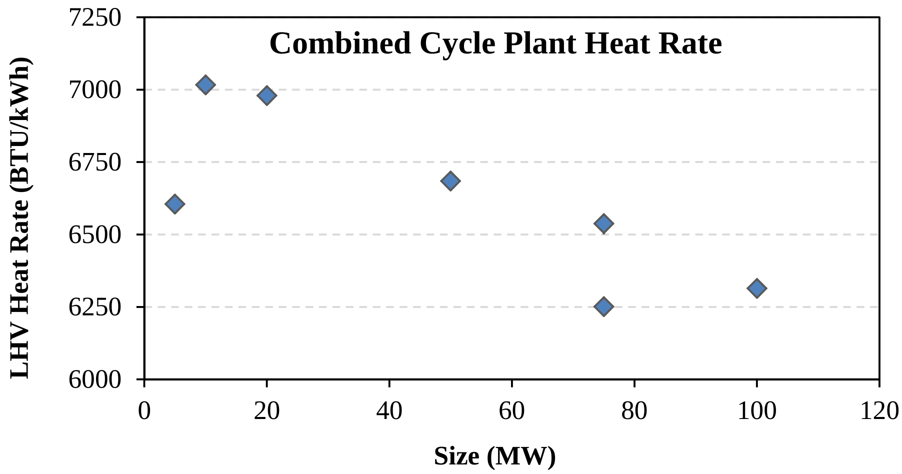


Figure 3.5. LHV heat rate for combined cycle plants of different sizes and configurations.

3.1.3 Cost Estimation

An add-on module of GT-PRO, named PEACE (Plant Engineering and Cost Estimator), was used to provide engineering details and cost estimation on roughly 35 components, covering heat recovery boilers, feed water heaters, wet condensers, cooling towers, air-cooled condensers, piping, pumps, and others used to model balance-of-plant components and sub-systems. The logical cost functions for all equipment and balance-of-plant are derived by PEACE from the detailed hardware specifications, so that any design change is immediately reflected in corresponding changes in both performance and cost.

It is important to note that without detailed design specifications of the equipment, pricing provided by each manufacturer is approximate and budgetary. Typically firm pricing from each vendor will be dependent on the technology, power plant location, freight costs, product line, efficiency, and so on. Our cost estimate, as developed from the GT Pro software, is somewhat more indicative of the project based on the averages of equipment suppliers pricing in the marketplace. Experience shows that GT Pro cost estimate is a good representation of the equipment price of a particular size category and might be within 10 to 20% of the budgetary cost provided by other competitive vendors.

Table 3.7 shows the summary of the PEACE cost analysis for different power plant configurations and sizes. The results show that for small size power plants (5–10 MW) the single cycle option is economically more beneficial than the combined cycle. For these systems the combined cycle was 20% to 30% more expensive than the single cycle option. The cost evaluation also highlighted that the normalized cost of combined cycle systems generally decreases with increasing plant size (Figure 3.6). For example, the normalized cost estimated for a 10 MW combined cycle plant ($2278/kW) was 85% higher than that calculated for the 100 MW combined cycle plant ($1240/kW).

Table 3.7. Summary of the PEACE Cost Analysis for Different Plants and Plant Sizes

		5 MW (ENG)	5 MW (CC)	10 MW (ENG)	10 MW (CC)	20 MW (CGT + HRSG)	20 MW (CC)	50 MW (CC)	75 MW (CC-A)	75 MW (CC-F)	100 MW (CC-F)
Power Plant:											
I Specialized Equipment	USD	4,213,000	4,933,000	4,440,000	5,979,000	15,792,000	18,550,000	38,727,000	43,347,000	43,928,000	65,985,000
II Other Equipment	USD	148,250	227,050	194,700	385,300	1,449,000	1,475,000	2,259,000	2,866,000	2,832,000	3,724,000
III Civil	USD	542,900	619,800	711,500	890,500	3,147,000	2,589,000	6,324,000	7,229,000	7,042,000	9,968,000
IV Mechanical	USD	798,600	1,144,000	36,545	1,585,000	2,926,000	3,194,000	36,694	7,258,000	7,714,000	10,962,000
V Electrical Assembly & Wiring	USD	304,750	427,200	379,750	553,300	1,074,000	1,081,000	2,089,000	2,694,000	2,907,000	3,547,000
VI Buildings & Structures	USD	786,400	753,600	1,033,000	36,553	1,687,000	1,718,000	2,671,000	3,217,000	3,459,000	3,783,000
VII Engineering & Plant Startup	USD	270,150	620,200	422,100	1,112,000	1,909,000	2,381,000	5,173,000	6,102,000	5,874,000	7,622,000
Contractor's Internal Cost	USD	7,064,000	8,725,000	8,200,000	11,533,000	27,984,000	30,988,000	63,260,000	72,713,000	73,755,000	105,590,000
VIII Contractor's Soft & Miscellaneous Costs	USD	1,557,000	36,587	1,845,000	2,658,000	6,544,000	6,928,000	14,245,000	16,536,000	16,884,000	36,884
Contractor's Price	**USD**	**8,621,000**	**10,728,000**	**10,046,000**	**14,191,000**	**34,528,000**	**37,916,000**	**77,506,000**	**89,249,000**	**90,639,000**	**129,603,000**
IX Power Plant's Soft & Miscellaneous Costs	USD	775,900	965,500	904,100	1,277,000	3,108,000	3,412,000	6,976,000	8,032,000	8,158,000	11,664,000
Total – Power Plant Cost	**USD**	**9,397,000**	**11,693,000**	**10,950,000**	**15,468,000**	**37,636,000**	**41,328,000**	**84,481,000**	**97,282,000**	**98,796,000**	**141,267,000**
Nameplate Net Plant Output	**MW**	**4.893**	**5.132**	**9.143**	**9.878**	**19.980**	**19.680**	**53.050**	**74.930**	**68.420**	**114.000**
Price per kW - Contractor's	**USD/kW**	**1762**	**2090**	**1099**	**1437**	**1728**	**1926**	**1461**	**1191**	**1325**	**1138**
Cost per kW – Power Plant	**USD/kW**	**1920.6**	**2278.5**	**1197.6**	**1565.9**	**1883.7**	**2099.7**	**1592.4**	**1298.3**	**1444.0**	**1239.9**

Note: Cost estimates are as of April 2014.

The information collected through GT-Pro simulations was used to develop the cost curves for each of the elements of the capital costs for power generation plants of sizes between 5 to 150 MW. From these cost curves, the empirical equations of costs were estimated and used as a basis to develop the LCC tool introduced in Chapter 4.

These cost curves were developed for the power generation plant main equipment, including the gas turbine, steam turbine, heat recovery boiler, and so on, as presented in Figure 3.6. For the majority of the plant's constituents, the slopes of the cost curves changes depending on the MW range considered, and typically differs between simple cycle and combined cycle plants.

Cost curves were also developed for other secondary equipment, such as pumps and tanks, cooling towers, heat exchangers, and so on and is presented in Figure 3.7. The same figure shows the empirical equations derived for the civil and mechanical work as well as the electrical assembly and wiring that is required for the installation of such power plants.

More details on these costs and their breakdown are described in Chapter 4, along with the description of the LCC tool developed.

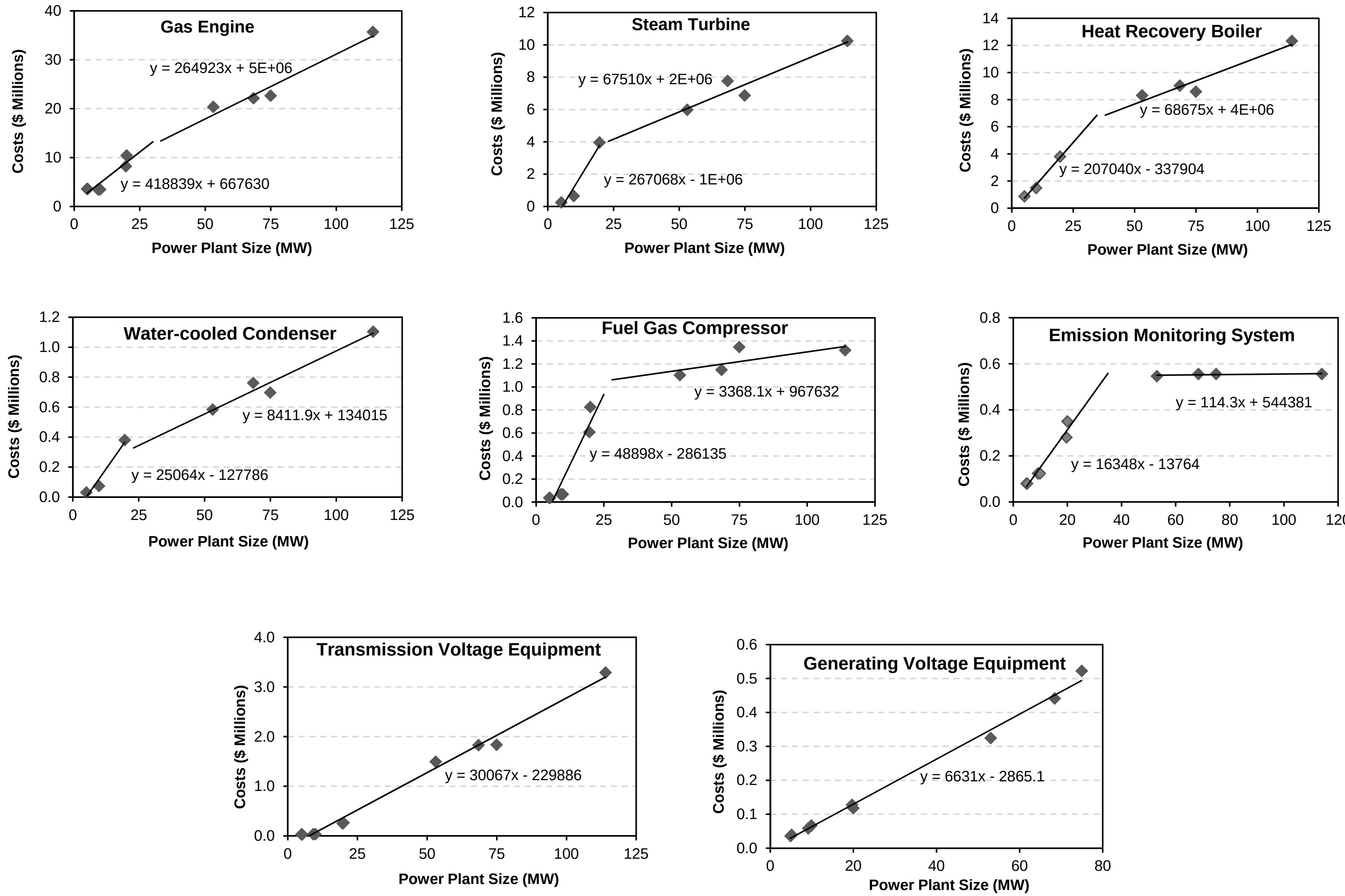


Figure 3.6. Empirical equation estimation for cost of main equipment for different power plant sizes.

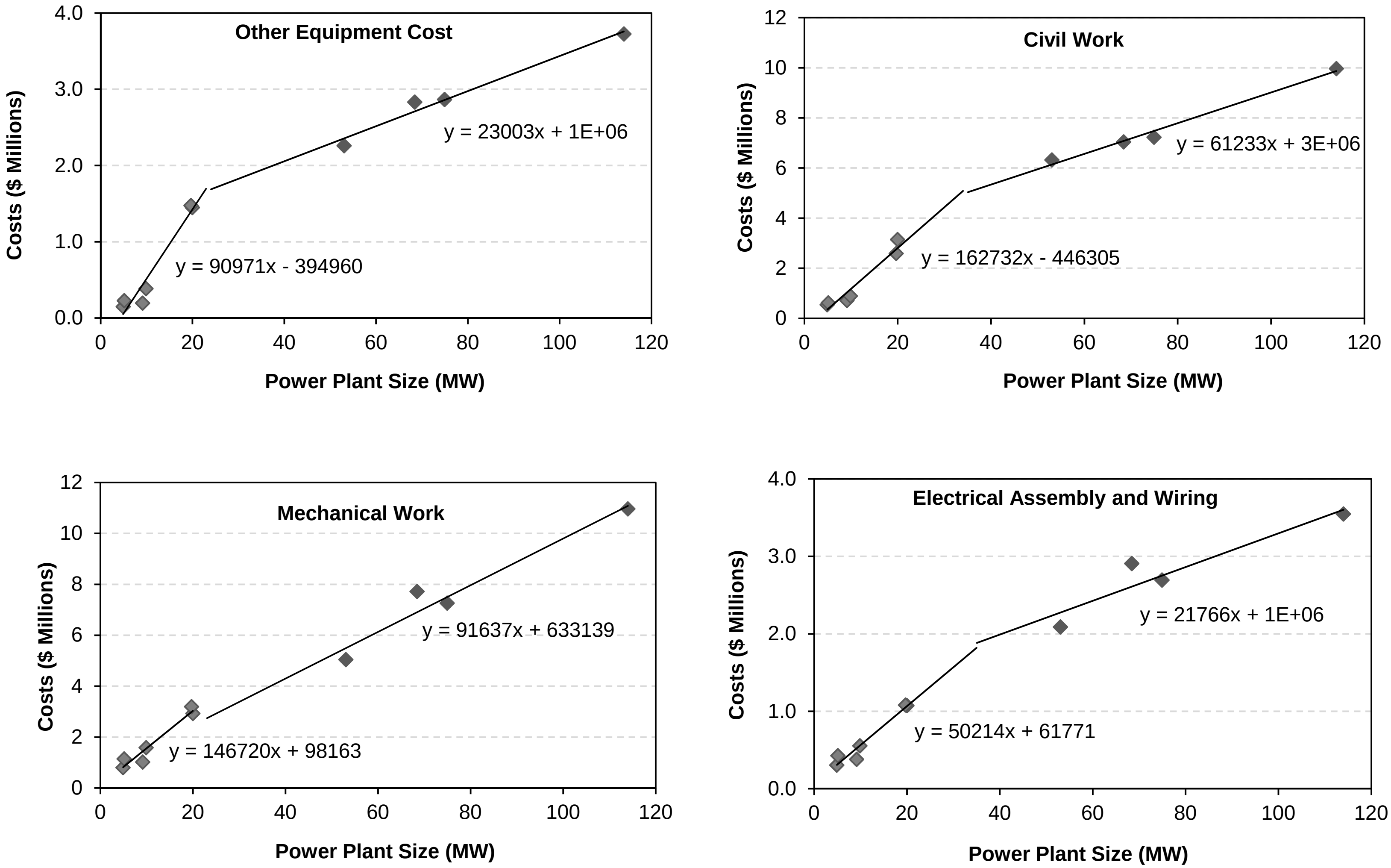


Figure 3.7. Empirical equation estimation for cost of other equipment, civil and mechanical work, and electrical assembly and wiring for different power plant sizes.

3.2 Hybrid Systems at Desalination Plants

In RO-based desalination plants, high-pressure pumps are energy intensive and use approximately 50% of the total energy consumed by the plant. LNG or NG can be used as a fuel to drive high-pressure pump motors in desalination plants, with the remaining energy provided by the electricity grid connection. Such systems with dual power source supply are referred to here as hybrid systems. This section presents the preliminary design parameters and cost information for LNG fueled engines that are be used as a basis for the LCC tool.

3.2.1 Design Specification

Table 3.8 summarizes the typical process components required for the use of LNG source to run high-pressure pumps in desalination plants. As shown, for the sizes between 0.5 and 5 MW considered in this study, reciprocating engines are considered to be the best option for running high-pressure pumps. For sizes of 2.5 MW and higher, a small steam turbine can be used to recover heat, however, as previously mentioned, the economics of a small steam turbine choice needs to be further investigated.

3.2.2 Cost Estimation

Preliminary and budgetary cost estimates for the engine generator drives with and without heat recovery have been performed for evaluating the economics of using LNG/NG as a fuel for hybrid systems. Various engine generators from different manufacturers, their related capital investments (for equipment), and O&M costs (estimated on kWh basis) were assessed.

Two vendors, Caterpillar and Wärtsilä, provided design and economic information on these products. It is important to note that the purpose of this study was not to select the best equipment among various models and manufacturers for cost and performance or to compare products from different vendors; however, the goal was to identify, for various LNG reciprocating engines sizes, the typical components, range of operating performance (e.g., efficiency), and approximate costs.

Tables 3.9 and 3.10 present the detailed information obtained from Caterpillar and Wärstilä, respectively. Models from Caterpillar were selected on the basis of the best electrical efficiency and varied if more emphasis was put on transient capability. The costs may also vary depending on other factors, such as the specific building or enclosures, connections to the grid (island mode or parallel to grid), switchgear and breaker requirements, site emission requirements, and more. From the data it is clear that when the engine size increases also the electrical efficiency increases, whereas the thermal efficiency decreases. High capital expenditures were obtained for the smallest engines of 0.5 and 1 MW, comparable to those of 5 and 10 MW engines. The O&M costs, as well as those of the SCR and CHP, were found to decrease with increasing engine size.

Wärtsilä only provided information on engine sizes between 2.5 and 10 MW. The cost of the Wärtsilä Gensets is higher for smallest engine sizes; the same O&M cost is applied regardless of the engine size considered.

Table 3.8. LNG Power Plants Coupled with Desalination Simulated Using GT PRO Software

Size (MW)	Regasifier	Prime Movers	Heat Recovery	Steam Turbine	Generator	Pollution Control	Electrical Connections
0.5	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Reciprocating Engine (CAT, Cummins)	▪ N/A*	▪ N/A*	▪ N/A*	▪ SCR	▪ HV/MV Substation
1	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Reciprocating Engine (CAT, Cummins)	▪ N/A*	▪ N/A*	▪ N/A*	▪ SCR	▪ HV/MV Substation
2.5	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Reciprocating Engine (CAT, Cummins)	▪ N/A* ▪ HRSG	▪ N/A* ▪ Steam turbines (1–2 MW - Siemens)	▪ N/A*	▪ SCR	▪ HV/MV Substation
5	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Reciprocating Engine (Wärtsilä 20V34SG SC)	▪ N/A* ▪ HRSG	▪ N/A* ▪ Steam turbines (1–2 MW - Siemens)	▪ N/A*	▪ SCR	▪ HV/MV Substation
10	▪ IFV (Air/Seawater) (Kopetz/Chart)	▪ Reciprocating Engine (Wärtsilä 20V34SG SC)	▪ N/A* ▪ HRSG	▪ N/A* ▪ Steam turbines (1–2 MW - Siemens)	▪ N/A*	▪ SCR	▪ HV/MV Substation

Note: *Typically not economical.

Table 3.9. LNG Reciprocating Engines Options for Running High-Pressure Pumps Provided by Caterpillar

Size[1] (MW)	Manufacturer	Model	Rating[2]	RPM	Heat Rate (BTU/kWh)	Electrical Efficiency[3] (%)	Thermal Efficiency[3] (%)	Emission Level NOx[4] (mg/Nm^3)	CapEX[5] ($/kW)	SCR Add[6] ($/kW)	CHP Add[7] ($/kW)	O&M[8] (cents/kWh)
0.5	Caterpillar	CG132-12	600	1800	n/a	41.1	46.6	500	800	200	100	2
1	Caterpillar	CG170-12	1200	1500	n/a	43.4	43.2	500	600	125	90	1.5
1.5	Caterpillar	CG132-16	1550	1500	n/a	43.0	43.7	500	550	100	80	1.3
2	Caterpillar	G3516H	2000	1500	n/a	44.3	41.3	500	550	90	70	1
2.5	Caterpillar	G3520H	2500	1500	n/a	45.4	41	500	550	80	70	1
5	Caterpillar	CG260-16	4000	900	n/a	43.8	42.4	500	600	70	70	0.9
5	Caterpillar	G16CM34	6520	720	7298	46.5	SS[9]	250–500	850	60	70	0.9
10	Caterpillar	G20CM34	9700	720	7275	46.9	SS[9]	250–500	800	50	65	0.8

[1]The engine size in MW will be equated to a relative size range of the desalination plant in MGD.

[2]Rating without radiator and without engine driven pumps (at ISO conditions).

[3]ISO efficiency for 1 g/bhp NOx setting.

[4] Emissions are based on the engine operating at steady state conditions and adjusted to the specified NOx level at 100% load. Values refer to engine emissions prior to treatment and subject to nominal tolerance based on fuel, site, and operating conditions.

[5]CapEx at rated output, includes engine, generator, emission control equipment, plant mechanical and electrical auxiliaries. Pricing is based on order and delivery in 2015 ± 20%.

[6]SCR added if installed in California or if required by local air board. SCR is not needed to meet NSPS ± 20%.

[7]CHP added for exhaust and jacket water heat recovery only ± 20%.

[8]O&M estimates include oil consumption and scheduled and unscheduled maintenance. Based on pipeline NatGas, it assumes operator at site for routine maintenance. Average U.S. dealer labor rates were used. Travel to site excluded. Operator excluded +/- 20%.

[9]SS: Site specific for gas compression engine (GCM) products.

Table 3.10. LNG Reciprocating Engines Options for Running High-Pressure Pumps Provided by Wärtsilä.

Size[1] (MW)	Manufacturer	Model	Total Power Output (MW)	Heat Rate[2] (kJ/kWh)	Electrical Efficiency[2] (%)	Cost Genset ($/kW)[3]	Cost HRSG ($)	Cost O&M[4] (cent/kWh)
2.5	Wärtsilä	6L34	2.5	n/a	n/a	1300	650K	1
5	Wärtsilä	9L34	4.1	7724	46.6	1225	675K	1
7.5	Wärtsilä	16V34	7.4	7724	46.6	815	700K	1
10	Wärtsilä	20V34	9.3	7724	46.6	700	725K	1

[1]The engine size in MW will be equated to a relative size range of the desalination plant in MGD.

[2]Heat rate and electrical efficiency at generator terminals, including engine-driven pumps, ISO 3046 conditions and LHV. Tolerance 5%. Power factor 0.8. Gas Methane Number >80.

[3]Exworks Finland.

[4]Assumes base-load operation and includes SCR reagent, catalyst replacement, and lube oil consumption.

The information collected through Caterpillar and Wärstilä were used to develop the cost curves for capital and O&M cost estimation for the engines used to run high-pressure pumps of sizes between 0.5 to 10 MW. From these cost curves the empirical equations of costs were estimated and used as a basis to develop the LCC tool introduced in Chapter 4.

These cost curves were developed for the power generation plant main equipment, including the engine, generator, emission control equipment, and plant mechanical and electrical auxiliaries (Figure 3.8).

More details on these costs and their breakdown are described in Chapter 4, along with the description of the LCC tool developed.

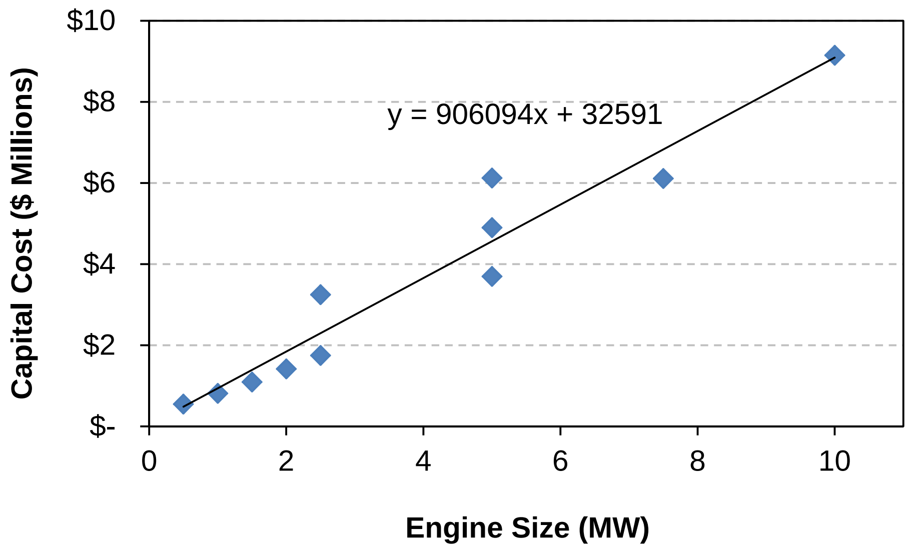


Figure 3.8. Capital costs for different engine sizes for high-pressure pumps and estimated empirical equation.

3.3 Grid Electricity at Desalination Plants

This section provides a general explanation of how projects with electrical loads get connected to the electrical power grid as their source of power, and a methodology for assigning first approximation cost estimates for the associated facilities.

3.3.1 Design Specifications

Connection of a new large load to the power grid is referred to as an interconnection. The electric utility typically has an established process for an interconnection that typically starts with a feasibility study associated with the new load. System impact studies are used to identify the components of the grid (whether belonging to that utility or a neighboring utility) that are not currently capable of supporting the interconnection along with other problems the interconnection may cause.

The electric loads associated with desalination plants can be interconnected to three components of the grid:

- Distribution system (system voltage 34.5kV or less)

- Subtransmission system (typically 66kV through 138kV)
- Transmission system (typically 230kV)

Typically for increasing loads, the interconnection voltage should also increase. However, other factors often influence this decision, particularly the proximity of electrical facilities to the desalination site.

3.3.2 Cost Estimation

The cost of interconnecting a desalination plant to the grid was estimated and used as guidance for developing the LCC tool. Many factors, in fact, can affect the cost of an interconnection and should be carefully considered at the design stage. Different cost estimations were developed for distribution and subtransmission interconnections.

The distribution system is commonly used for new loads that do not exceed approximately 10MW. A typical distribution feeder can handle a 5MW load. Because of the simplicity of distribution systems, the cost of a dedicated feeder with a capacity of 10MW is usually far less than a higher voltage alternative. The cost of a dedicated feeder with a thermal capacity of 10 MW from an existing substation that has sufficient capacity to serve the new load was estimated at $250k plus $100k per mile of overhead feeder or $250k per mile for underground feeder.

Subtransmission systems wheel power over an area within typically 10 miles of its origin at a substation with a connection to the transmission system. As a reference to the scales involved, a subtransmission system can supply hundreds of megawatts to a load, may have significant generation connected, and can move large amounts of power around within a city. A subtransmission interconnection is ideal for loads from 10MW to more than 100MW. Because the system voltage is higher than what the desalination plant requires, a new substation is required. This substation is usually located at the edge of the plant at a convenient place to route the required transmission line(s) and distribution feeders. The key piece of equipment in the substation is the transformer that transforms the voltage from the incoming line down to a voltage appropriate for a distribution system. The estimated cost of a substation includes many features such as major equipment, permitting, engineering and design, construction, project management, testing and commissioning, and an allowance for the unexpected. The cost was estimated at $6 million for a substation with a primary connection to a subtransmission system. A rate of $1 million per mile may be used as an approximation of the cost of the transmission line from the point-of-interconnect to the new substation.

In transmission interconnection, the 230kV transmission system moves power both within large cities and regionally. To tap into this source of power, a substation with an appropriately designed transformer and all of the associated balance of plant systems is required. There are many considerations in the planning and estimating of transmission voltage substations. A connection to the 230kV system can easily supply hundreds of megawatts of power. For budgeting or other planning purposes, the substation cost can be estimated at approximately $20 million. For 230kV transmission lines $2 million per mile (without permitting or right-of-way acquisitions that are significant efforts) is estimated.

In general, transmission interconnections are much more costly and complicated than subtransmission interconnections. Similarly, subtransmission interconnections cost more and are much more complex than distribution interconnections. The transmission interconnection should be considered when the load from the plant is higher than 100MW, or it is the only practical option because of proximity. Thus, for this study that only considered power generation plants of sizes smaller than 100 MW, the transmission interconnection was not included in the LCC analysis.

Chapter 4

Software Tool for Comparative Analysis of LNG/NG Versus Grid Power Supply: Principles and Guidance Manual

This section contains details on the fundamental principles and elements of the Excel-based spreadsheet developed to conduct the cost comparison between purchasing electricity directly from the power grid and the use of commercially supplied LNG/NG for self-generation of power and/or pumping for desalination processes. The elements of the conceptual design and operating parameters of the gas engines/turbines employed to power desalination plants of various capacities and their related capital and O&M cost information, summarized in previous sections, have been used for the development of the spreadsheet and further integrated into the tool. The tool does not specifically calculate the energy use breakdown in a SWRO process; rather, it compares alternative energy generation processes. For site-specific applications of the tool, it is recommended that the user refines the default values currently provided in the tool of energy consumption for a SWRO plant through independent studies (e.g., modeling, pilot testing).

4.1 Principles of the Tool

The LCC and LCOE evaluation are methods widely used in the public works industry for developing economic comparison of project options and quantitatively evaluating their relative attractiveness. The LCC evaluation is not a financial analysis tool. Once the most attractive option(s) is (are) selected, financial analysis of capital requirement and cash flows takes place, taking into consideration additional factors that are not relevant to economic, or comparative, analysis.

The model incorporates three alternatives: on-site gas-fired power generation; hybrid systems including gas engines to run high-pressure pumps and additional electricity directly from the power grid; and the sole power grid option. These three alternatives can be compared using two different fuel options: NG and LNG. Figure 4.1 summarizes the different alternatives included in the LCC tool.

Project options may have different capital costs, different annual costs such as operations and maintenance, different production of benefits, different implementation time frames, and assets that have different useful lives. To provide a fair basis for the economic determination of relative attractiveness, all of these factors should be taken into account. The LCC model provides this functionality. Project options are also considered over the same life cycle period. Analytical results of the LCC analyses are provided as present values of initial and life cycle capital and annual costs to enable meaningful comparison of the attractiveness of options with diverse characteristics.

The following sections summarize the key elements of LCC and LCOE analysis, their relevance to power source selection in desalination process economics, and guidance documents for conducting such analysis.

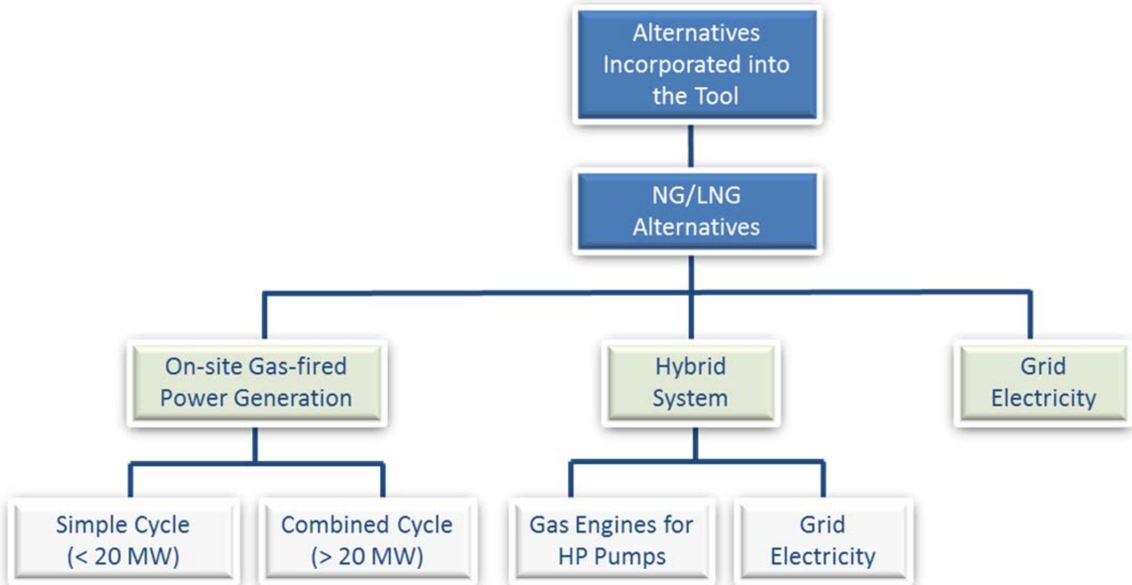


Figure 4.1 Alternatives incorporated into the tool.

4.2 Elements of the Tool

The module has been developed in Microsoft Excel and includes a series of worksheets each with different calculation capabilities. Figure 4.2 shows an overview of the tool and content of each worksheet. In the workflow presented in Figure 4.2, six major elements can be identified:

- General information
- Power requirement calculation
- Selection of fuel and selection of alternatives
- Set LCC period, cost, financial and economic assumptions
- Life cycle capital and O&M costs
- Life cycle GHG emissions

Most of the economic assessments of each project option are computed in different worksheets based on the power generation alternative selected. These worksheets address the calculation of life-cycle capital and O&M costs. In the analysis, different cost relationship assumptions are used, most of which should be evaluated by the user for each application of the model.

The total LCC is used to assess the differences in cost and timing of cost among different project alternatives. These costs are discounted to a base year by using a present value analysis.

Most of the costs mentioned are incurred over the LCC period, which equals or exceeds the life of the asset (e.g., gas engines; 20–25 years). The present values (PV) of all the future capital and annual costs must be calculated for each alternative being considered. The typical method to compute PV is first to compute a future value ("FV") at year "n" using an appropriate escalation rate and then to compute the PV of that future value using an appropriate discount rate. These computations are shown in Equations 4-1 and 4-2:

$$FV = \sum_1^x C_n * (1 + p)^n \qquad (4\text{-}1)$$

$$PV = \sum_1^x \frac{FV_n}{(1+i)^n} \qquad (4\text{-}2)$$

Where:

C_n = cost at year “n” for the above indicated cost categories

n = total number of years being considered;

p = expected average rate of cost escalation;

i = discount rate; and

x= number of cost elements

The project alternative with the lowest LCC should be considered as the most attractive of the alternatives in terms of cost, but other noncost features can be important and should also be considered in the selection of the desired alternative.

The LCOE was also used as a metric to compare the cost of energy generated by the different power generation options. The LCOE represents the cost per kilowatt-hour of building and operating a power generation alternative given an assumed life cycle. The key elements for the LCOE calculation include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, etc. The LCOE can be calculated using the following equation (4-3):

$$LCOE = \frac{LCC}{Q} \cdot (UCRF) \qquad (4\text{-}3)$$

Where:

LCC = present value of the LCC

Q = annual energy output (kWh);

UCRF = uniform capital recovery factor, which is expressed by the following equation:

$$UCRF = \frac{d \cdot (1+d)^N}{(1+d)^N - 1} \qquad (4\text{-}4)$$

Where:

N = analysis period;

d= discount rate

Life cycle GHG emissions were also estimated for the proposed alternatives. For LNG and NG-based on-site power generation options, the GHG emitted are from direct emissions caused by the use of the fuel. For the grid electricity connection, the electricity usage is responsible for the indirect GHG produced. In hybrid systems, both electricity usage (indirect emissions) and the fuel consumption (direct emissions) play a role in the GHG emissions evaluation.

The accuracy in calculating GHG emissions from energy usage is directly dependent on the accuracy of the data available for energy utilization and associated GHG emission factors per unit of energy consumed. For example, for a hybrid system, the GHG emissions were calculated with the following equations:

$$GHG\ Emissions = GHG_{LNG/NG} + GHG_{GRID} \qquad (4\text{-}5)$$

$$GHG_{LNG/NG} = EF_{LNG/NG} \cdot TH \qquad (4\text{-}6)$$

$$GHG_{GRID} = EF_{GRID} \cdot Q \qquad (4\text{-}7)$$

Where:

$GHG_{LNG/NG}$ = GHG emitted by the operation of gas engines (ton-CO_2/year);

GHG_{GRID} = GHG emitted by the grid power (ton-CO_2/year);

$EF_{LNG/NG}$ = emission factor for LNG/NG (ton-CO_2/MMBTU);

EF_{GRID} = emission factor for the grid (ton-CO_2/kWh);

TH = annual thermal energy of NG/LNG (MMBTU/year).

The emissions factors used in this study for the LNG-based processes (the on-site power generation and high-pressure pumping of an hybrid system) was 0.05306 tonnes CO2/MMBTU, selected for a NG higher heating value range of 1,025 to 1,050 BTU/scf and carbon content of 14.47 gC/MBTU (API, 2013).

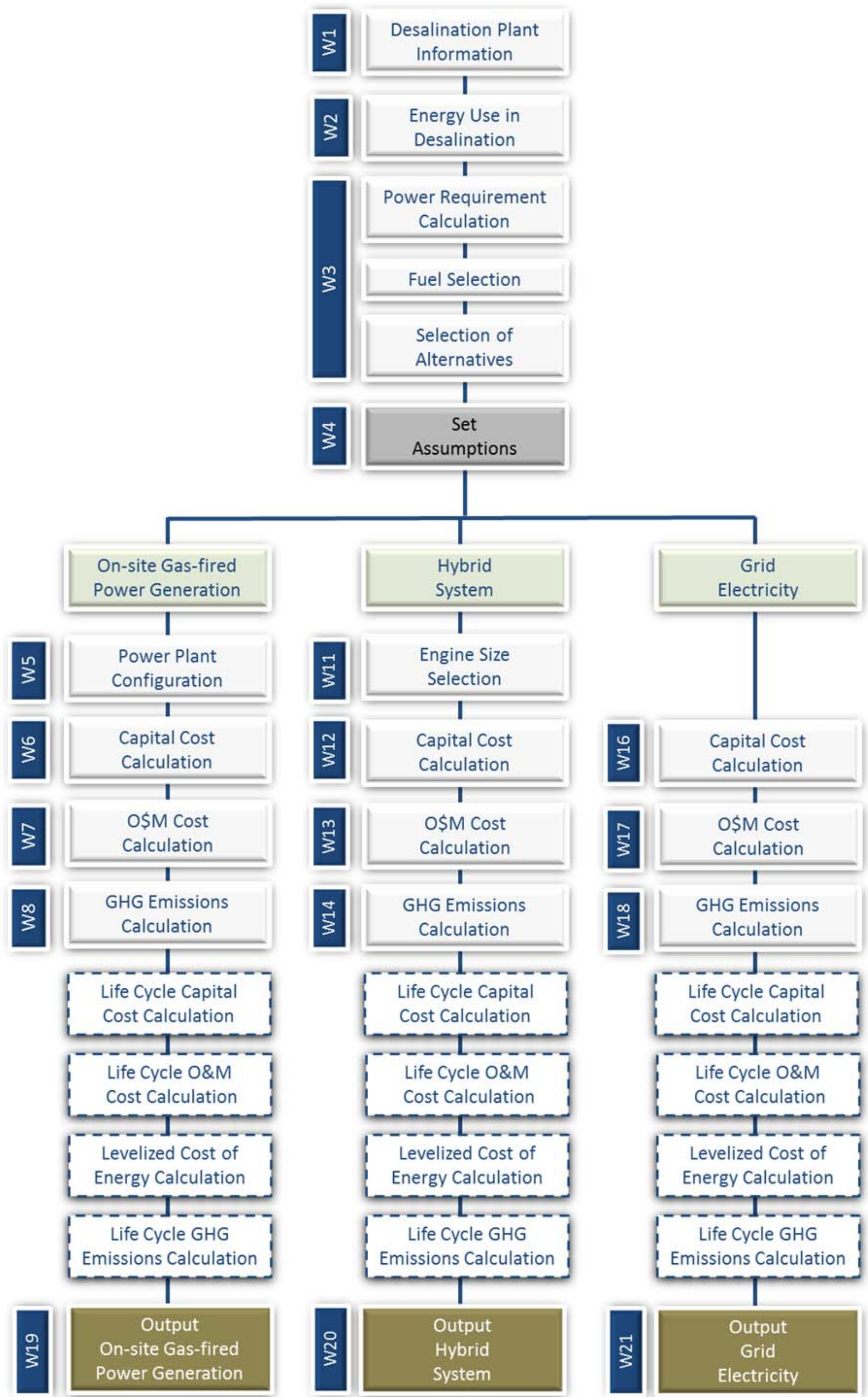


Figure 4.2 Overview and workflow of the tool.

4.3 Guidance Manual

This section serves as a reference for the use of the LCC tool and should be used alongside it. The software is set up to allow the user to evaluate three different power source alternatives for desalination plants and provides the option to select NG or LNG as a fuel for the power plant or engines utilized. The algorithms used in the worksheets (e.g., LCC analysis, greenhouse gas emissions) are similar and tailored for each of the options selected. The following presents the definitions and further explains the algorithms used for assessing these alternatives.

4.3.1 How to Use the Tool

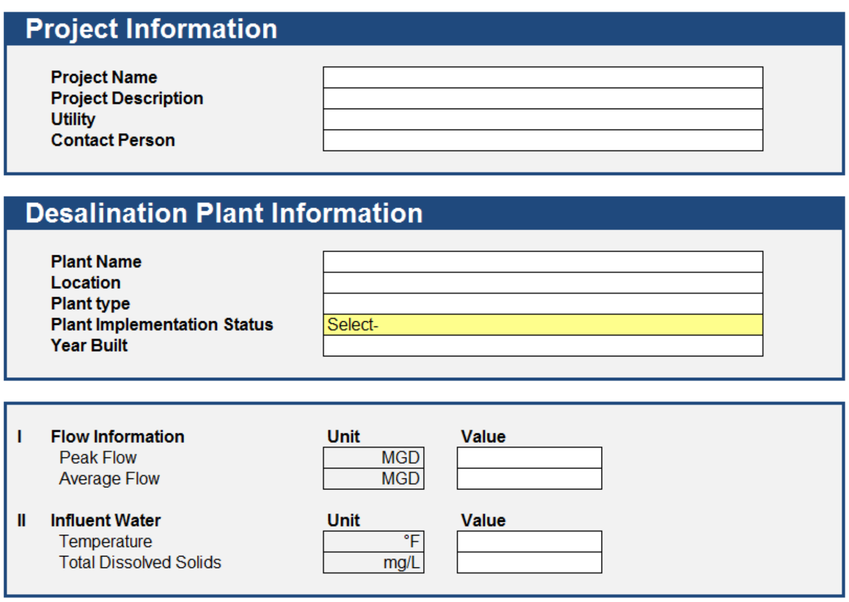
All worksheets in the workbook are protected to prevent inadvertent changes to cell formulas and/or values. Every worksheet contains cells that are intended for the user to enter data and/or change data. These cells are indicated with white cell fill color and black cell outline. Cells that have a gray fill and black cell outline cannot be changed, as they contain formulae rather than values.

4.3.2 Desalination Plant Information Worksheet

This input page takes general information regarding the project and data on the desalination plant. In particular, desalination process information includes both flow and selected water quality information, particularly:

- Peak and average flows
- Influent water temperature
- Influent water total dissolved solids

Figure 4.3 shows a screenshot of the Desalination Plant Information worksheet.



Project Information

Project Name
Project Description
Utility
Contact Person

Desalination Plant Information

Plant Name
Location
Plant type
Plant Implementation Status: Select-
Year Built

		Unit	Value
I	**Flow Information**		
	Peak Flow	MGD	
	Average Flow	MGD	
II	**Influent Water**		
	Temperature	°F	
	Total Dissolved Solids	mg/L	

Figure 4.3 Screenshot of the Desalination Plant Information worksheet.

4.3.3 Energy Use Worksheet

This input page takes data regarding the unit energy use by each process or compartment of the desalination plant. In desalination plants using RO membranes the major process compartments that require energy are:

- Desalination plant intake
- SWRO plant, including
  - Pretreatment processes
  - High-pressure pumps
  - Other pumping
  - Chemical feed systems
  - Membrane cleaning
  - Solid handling
- Product water
- Facility

Energy use in the SWRO plant is a function of various parameters, which include the feed water recovery, intrinsic membrane resistance (permeability), operational flux, feed water salinity and temperature fluctuations, product water quality requirements, and system configuration (e.g., use of energy recovery devices). The determination of the energy breakdown within a SWRO is site specific, often presented for narrow aspects of the project or at ideal conditions (new membrane, no fouling, etc.) (Ghiu, 2014). A number of studies have attempted the estimation and analysis of the power requirements associated with various phases of the desalination process in order to identify opportunities for future reduced energy demand (Cooley and Heberger, 2013; Elimelech and Philip, 2011; Jacangelo et al., 2013; Pinzon, 2013; Subramani et al., 2011; Voutchkov, 2008; WaterReuse Association, 2011). This study and the accompanying tool does not provide guidance on how to determine the energy use at the desalination plant; rather it focuses on the life cycle cost analysis of different power source alternatives. Nevertheless, various resources are available for the estimation of energy use in SWRO and few examples are presented in the following.

- **Reverse Osmosis System Analysis (ROSA) model**. The model has been used to predict the performance of membranes and related energy requirements of high-pressure pumps for desalination.

- **DORIS, web-based tool.** Developed by the tailored collaboration between the Water Research Foundation and West Basin Municipal Water District; the tool calculates all components of the energy consumption by a seawater RO treatment system, from intake to pretreatment, first pass RO, second pass RO, posttreatment, and distribution system (Ghiu, 2014).

- **Pilot Testing.** Estimations of energy use as well as variability in energy performance of SWRO to capture seasonal variations should be preferably determined through pilot studies.

Figure 4.4 shows a screenshot of the Energy Use Information worksheet and reports the reference values used in this study. The reference values reported in the worksheet for each of the categories were obtained from a seawater desalination plant demonstration study conducted in California (Loveland, 2015). Users are recommended to conduct their own pilot or demonstration studies to estimate the energy consumption values. From the reference values reported, it is clear that the process requiring most of the energy per unit of water produced is the operation of high-pressure pumps (7.5 kWh/kgal). On the basis of the input, the spreadsheet calculates the total unit energy requirement for the desalination plants (e.g., kWh required for each gallon of water treated).

Total Energy Requirements of Desalination Plant

Please input the breakdown of energy used by various processes or compartments in your desalination plant.

		Units	Input	Reference Value
I	Desalination Plant Intake Energy Use	kWh/kgal		0.7
II	Reverse Osmosis Plant Energy Use	Units	Input	
	Pretreatment facility energy use	kWh/kgal		0.02
	Reverse osmosis high pressure pump	kWh/kgal		7.5
	Reverse osmosis other pumps	kWh/kgal		2.02
	Chemical feed system	kWh/kgal		0.03
	Membrane cleaning system	kWh/kgal		0.0001
	Solids handling system	kWh/kgal		0.14
		Units	Input	Reference Value
III	Product Water Energy Use	kWh/kgal		4.8
		Units	Input	Reference Value
IV	Facility Energy Use	kWh/kgal		0.2
		Units	Value	
	Total Unit Energy Requirement	**kWh/kgal**	**0.00**	

Figure 4.4. Screenshot of the Energy Use worksheet.

4.3.4 Scenarios Worksheet

This worksheet includes the calculations for the total power requirements to run the desalination plant based on average demand and peak demand conditions. The power requirements based on the peak demand condition are used to calculate the capital cost of equipment in the LCC analysis, whereas the power requirements based on the average demand condition are used as a basis for the O&M costs.

In this worksheet the user is able to select the desired fuel to power the on-site power generation facility or the engines that run the high-pressure pumps. The user is able to select between the NG option and the LNG alternative in a drop-down menu.

After selecting the fuel, the user can now select the scenarios to be compared through the LCC analysis. Three scenarios are proposed:

- *On-site gas-fired power generation*. NG or LNG is used as the sole fuel for the on-site power generation facility that powers the desalination plant.
- *Hybrid system*. NG or LNG is used as the fuel for the engines that drive high-pressure pump motors in the desalination plant. The remaining energy is provided through the grid connection.
- *Grid Electricity*. The grid connection is the sole source that powers the desalination plant.

The user can select one of these options or up to three options contemporarily that are compared in the LCC analysis from the category buttons on the left.

Figure 4.5 shows a screenshot of the Scenario worksheet.

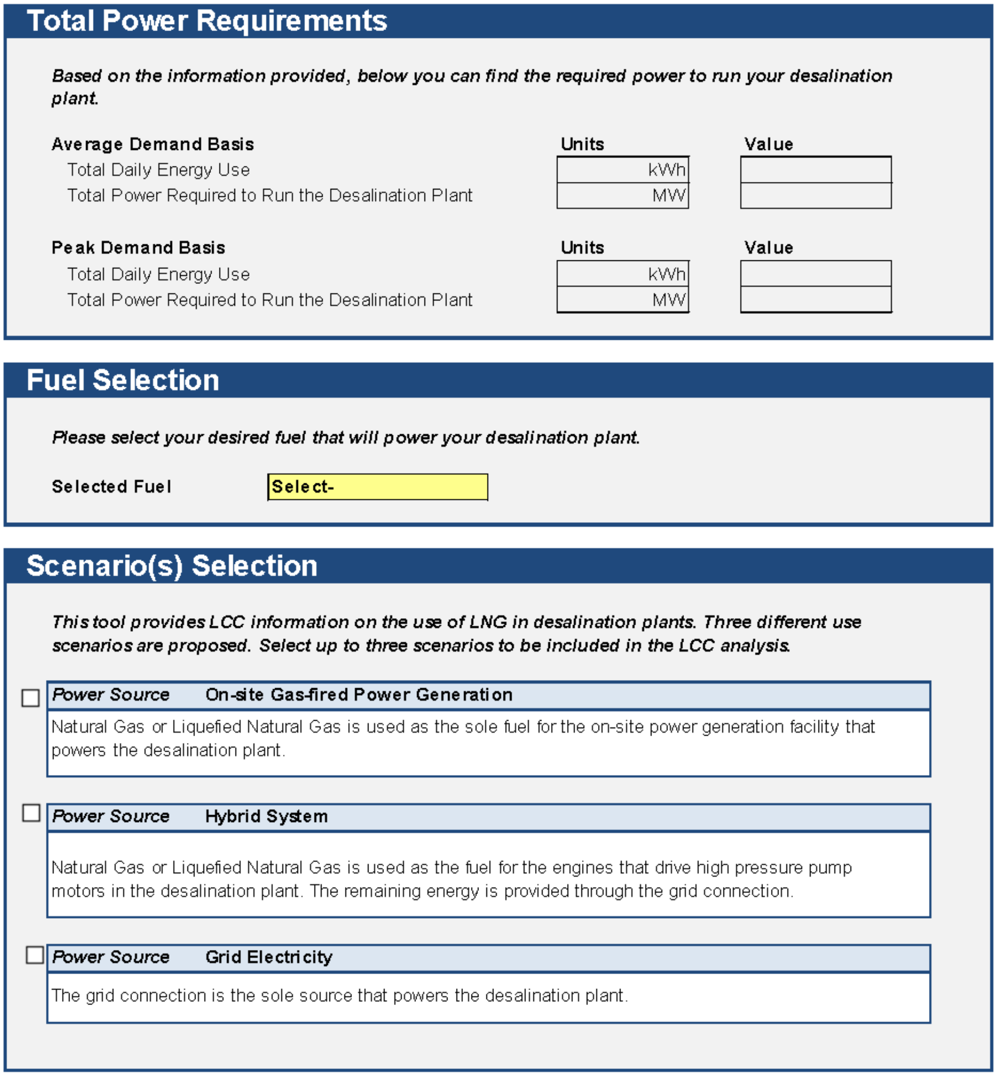


Figure 4.5. Screenshot of the Scenarios worksheet.

4.3.5 Assumptions

In the Assumptions worksheet, the user should insert the assumptions incorporated into the LCC analysis. The assumptions are shown in five categories:

- Life Cycle Assumptions
- Cost Assumptions
- Financial Assumptions
- Economic Assumptions
- Fuel and Electricity Charges Assumptions

Figure 4.6 shows a screenshot of the LCC Assumptions worksheet.

4.3.5.1. Life Cycle Assumptions

The **Life Cycle Period** is the time over which projected capital costs and annual costs of project options are evaluated for all the project options. Life cycle period of analysis and estimated useful lives of assets may be—but are not necessarily—the same number of years. The costs of alternatives are compared over a given period of time equal to the LCC period. In this spreadsheet, the life cycle period for comparison of project options is the same for all options, and typically the life cycle should be at least as long as the expected useful life of the major facility components of the option with the longest useful life. With this tool, the maximum value allowed for the life cycle period is 50 years. If the user is interested in evaluating the different options at different life cycle periods, then different analyses should be performed with the desired LCC assumption input.

In addition to life cycle period, the user must specify the initial year of operation and the year of analysis. The **Initial Year of Operation** is the first year of the life cycle period that follows the construction period. With this tool, all options considered have the same initial year of operation.

The **Year of Analysis** is the date at which the present values of all future LCC are determined. In the previous example this would be 2015; however, a different year could be assigned if it were appropriate to do so.

The default values for these inputs are reported in Figure 4.6.

4.3.5.2. Cost Assumptions

The user should enter the **Cost Estimate Basis Year**, which generally is the same as the Year of Analysis mentioned earlier.

The **Construction Cost Escalation** and **O&M and General Cost Escalation** values should also be provided by the user. Construction cost escalation is typically based on local experience and is sometimes verified by recent history of the *Engineering News-Record* Construction Cost Index (the "ENR"). O&M and General Cost Escalation should always be based on local experience but sometimes is verified by recent history of the Consumer Price Index, published by the Bureau of Labor Statistics.

The default values for these inputs are also reported in Figure 4.6.

4.3.5.3. Financial Assumptions

It is customary for some clients, for capital improvement planning purposes, to assume all **LCC Capital Costs** are to be long-term debt financed and shown as annual debt service values rather than as lump sum capital requirements. This enables financing costs to be included in the analysis and annual cash flow behavior to be more reflective of actual resulting annual costs. The LCC model allows the user to redefine how capital costs are to be treated: either as bond funded with debt service estimated or as lump sum capital costs. On the basis of this selection, capital costs are treated as lump sums or debt service costs. But no capital activity can be divided with part financed with debt and the other part on a pay-as-you-go basis.

Debt service financing interest rate, bond maturity years, and the financing costs that will be capitalized are the necessary data for the model to compute **annual debt service**. Debt service is computed (depending on the debt service or lump sum previous selection) using equal annual payments of principal and interest and assumes that the bond sales will not include capitalized bond reserve funding or costs of sureties to cover bond reserve requirements. If bond reserves are required, they will have sequestered reinvestment earnings and any minor deficits will be immaterial.

The bond sales will not include **capitalized interest**; debt service will commence promptly the year immediately following bond sales.

For economic comparison purposes of the LCC analysis, it is assumed that level debt service throughout the debt repayment period is appropriate. Similarly, it is assumed that any bond reserve augmentation that may be required by bond indenture(s) shall be handled by a surety instrument or by a capitalized deposit in a sequestered fund that earns reinvestment interest and is used for the final payment of principal and interest.

The default values for these inputs are reported in Figure 4,6.

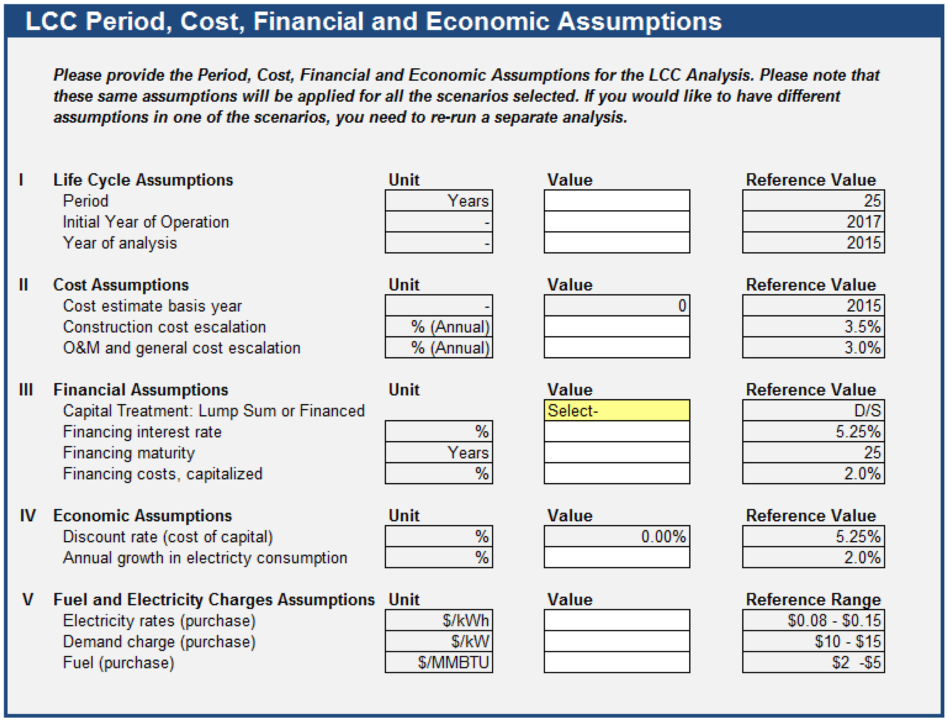
4.3.5.4. Economic Assumptions

Economic Assumptions include discount rates for computing present values of future costs. A typical **discount rate** determination is based on risk-adjusted cost of capital. A typical discount rate value should be adjusted to reflect the cost of capital behavior.

The final assumption shown on the Economic Assumption is the figure for assumed growth in electricity consumption.

4.3.5.5. Fuel and Electricity Charges Assumptions

The Fuel and Electricity Charges Assumptions section includes the electricity rates and the demand charges for purchase and the fuel cost. The default values for these inputs are reported in Figure 4.6.



LCC Period, Cost, Financial and Economic Assumptions

Please provide the Period, Cost, Financial and Economic Assumptions for the LCC Analysis. Please note that these same assumptions will be applied for all the scenarios selected. If you would like to have different assumptions in one of the scenarios, you need to re-run a separate analysis.

		Unit	Value	Reference Value
I	**Life Cycle Assumptions**	**Unit**	**Value**	**Reference Value**
	Period	Years		25
	Initial Year of Operation	-		2017
	Year of analysis	-		2015
II	**Cost Assumptions**	**Unit**	**Value**	**Reference Value**
	Cost estimate basis year	-	0	2015
	Construction cost escalation	% (Annual)		3.5%
	O&M and general cost escalation	% (Annual)		3.0%
III	**Financial Assumptions**	**Unit**	**Value**	**Reference Value**
	Capital Treatment: Lump Sum or Financed		Select-	D/S
	Financing interest rate	%		5.25%
	Financing maturity	Years		25
	Financing costs, capitalized	%		2.0%
IV	**Economic Assumptions**	**Unit**	**Value**	**Reference Value**
	Discount rate (cost of capital)	%	0.00%	5.25%
	Annual growth in electricty consumption	%		2.0%
V	**Fuel and Electricity Charges Assumptions**	**Unit**	**Value**	**Reference Range**
	Electricity rates (purchase)	$/kWh		$0.08 - $0.15
	Demand charge (purchase)	$/kW		$10 - $15
	Fuel (purchase)	$/MMBTU		$2 -$5

Figure 4.6. Screenshot of the LCC Assumptions worksheet.

4.3.6 On-site Power Generation Worksheets

The economic and environmental analysis of the on-site power generation option will be conducted in four worksheets, as follows:

1. Power generation plant size and plant configuration selection (Power Plant Configuration worksheet; Figure 4.7)
2. Capital cost determination (NG LNG—CAP worksheet; Figure 4.8)
3. O&M cost determination (NG LNG—O&M worksheet; Figure 4.9)
4. GHG emissions evaluation (NG LNG—GHG worksheet; Figure 4.10)

In the first ***Power Plant Configuration* worksheet**, the user can select to have the power plant only providing power to the desalination plant or to have a power plant of larger size to satisfy additional needs. If this last option is selected by the user, then the MW of excess power needed should be specified in the appropriate cell. The tool then automatically calculates the power plant size based on peak and base production capacity. The peak capacity is used as a basis for the capital cost calculation, whereas the base capacity is used to determine the O&M costs. On the basis of the peak plant capacity, the tool automatically selects the power plant configuration as:

- Simple Cycle: for power plant sizes equal or smaller than 20 MW
- Combined Cycle: for power plant sizes greater than 20 MW

In the second ***NG LNG—CAP* worksheet** the necessary inputs for the calculation of the capital cost should be entered by the user in the appropriate cells. All capital costs should be in dollars. If the user lacks the cost information for some or all of the fields, the reference values can be used. The reference values have been estimated using the cost curves previously developed in Chapter 4. The main elements included in the capital cost analysis are presented in the following Table 4.1.

Table 4.1. Elements of the Capital Cost Analysis for the On-site Power Generation Alternative

Class	Elements	
Special Equipment	▪ LNG regasification system ▪ Gas Turbine Package ▪ Steam Turbine package ▪ Heat recovery boiler ▪ GT Exhaust System ▪ Water-cooled Condenser ▪ Air-cooled Condenser	▪ Inlet Air Chilling/ Heating System ▪ Fuel Gas Compressor ▪ Emission Monitoring System ▪ Distributed Control System ▪ Transmission Voltage Equipment ▪ Generating Voltage Equipment
Other Equipment	▪ Pumps and Tanks ▪ Cooling tower ▪ Auxiliary heat exchangers ▪ Feed water heater(s) and auxiliary boiler ▪ Makeup water treatment system and wastewater system	▪ Bridge crane(s) ▪ Station/Instrument air compressors ▪ Reciprocating Engine Genset(s) ▪ General Plant Instrumentation ▪ Low, Medium voltage equipment ▪ Miscellaneous equipment
Civil	▪ Site work ▪ Excavation and Backfill	▪ Concrete ▪ Road, parking and walkways
Mechanical	▪ On-site transportation and rigging ▪ Equipment erection and assembly	▪ Piping ▪ Steel
Electrical Assembly and Wiring	▪ Controls	▪ Assembly and wiring
Building and Structures	▪ Turbine hall ▪ Administration, control room, warehouse	▪ Water treatment system ▪ Guard house
Engineering and Plant Startup	▪ Engineering	▪ Start-up
Contractor Miscellaneous Costs	▪ Contingency (labor, equipment) ▪ Profit (labor, equipment) ▪ Commodity	▪ Bonds and insurance ▪ Contractor’s fees
Owner’s Soft and Miscellaneous Costs	▪ Permits, licenses, fees ▪ Legal and financial costs	▪ Escalation and interest during construction ▪ Project administration and developer’s fees

The reference values cannot be modified at the user's discretion. The user should leave the cell unchanged if that cell does not apply to the project.

It is important to note that for a simple cycle plant configuration, the following equipment is not required and the user should consider their cost as zero:

- Steam turbine package
- Heat recovery boiler
- Water-cooled condenser

If the selected fuel for the on-site power generation plant is NG, the LNG regasification system is not required and the cost should be considered as zero.

On the basis of the input specified, the model automatically calculates the total capital cost for the on-site power generation option.

In the third ***NG LNG—O&M*** **worksheet** the necessary input for the calculation of the O&M costs should be entered by the user in the appropriate cells. The elements included in the O&M cost analysis are:

- Fixed operating costs (e.g., labor)
- Variable operating costs (e.g., oil consumption and equipment maintenance, and LNG/NG fuel consumption)

To calculate the unit labor cost for the total labor cost calculation, the user is directed to a supplementary spreadsheet within the *Labor—NG LNG* worksheet by clicking the tab "Calculate." Details on the *Labor—NG LNG* worksheet will be presented in the next sections.

In order to calculate the variable operation costs, the user must input the expected power plant efficiency and the oil consumption and equipment maintenance unit cost, in addition to the energy costs assumptions that were provided in the *LCC Assumption* worksheet.

On the basis of the input specified, the model automatically calculates the total O&M costs for the on-site power generation option.

In the first *Power Plant Configuration* worksheet, the user had the opportunity to select the option of having a power plant of larger size to satisfy additional needs. In this case, potential revenues can be generated if the excess power is sold to other users, such as selling to the grid. Thus, in this worksheet, the user can input the selling price of electricity and the tool automatically calculates the revenue gained through selling electricity. The tool also accommodates entering additional gains from other sources of revenue that will be then accounted in the total revenue.

In the fourth ***NG LNGM—GHG*** **worksheet,** the necessary input for the calculation of the GHG emission should be entered by the user in the appropriate cells. The input required is the GHG emission factor for NG or LNG application, which is 0.05306 ton/MMBTU, as reported in previous chapters. On the basis of the input specified, the model automatically calculates the total GHG emissions for the on-site power generation option.

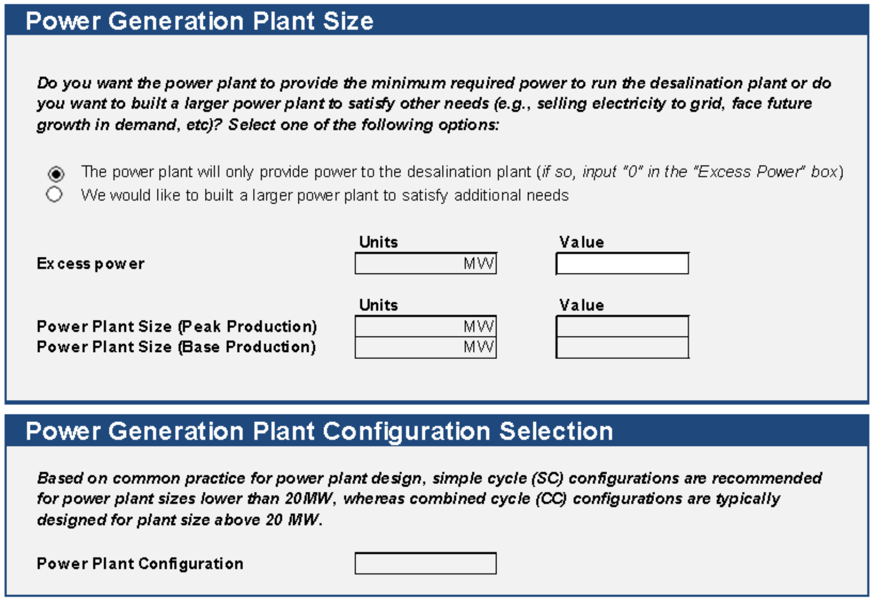


Figure 4.7. Screenshot of the On-site Power Generation worksheets.

Input for Determination of Capital Cost for Gas-fired Power Generation

Your capital cost calculation will be based on the peak production.

	Units	Value
Power Plant Size (Peak Production)	MW	0

Please provide the necessary input to determine the capital cost for a power plant co-located with the desalination plant. If you don't know the cost of each item, use of the reference value is recommended.

		Unit	Value	Reference Value
I	**Special Equipment**			
	LNG Regasification System	$		$ -
	Gas Turbine Package	$		$ 667,630
	Steam Turbine Package	$		Not Required
	GT Exhaust System	$		$ 100,145
	Heat Recovery Boiler	$		Not Required
	Water-cooled Condenser	$		Not Required
	Air-cooled Condenser	$		$ -
	Inlet Air Chilling/ Heating System	$		$ -
	Fuel Gas Compressor	$		$ 36,480
	Emission Monitoring System	$		$ (13,764)
	Distributed Control System	$		$ -
	Transmission Voltage Equipment	$		$ 15,810
	Generating Voltage Equipment	$		$ 7,905
	Other	$		
	Other	$		
	Subtotal Special Equipment	$	$0	$814,205

		Unit	Value	Reference Value
II	**Other Equipment**	$		$ -
III	**Civil**	$		$ (446,305)
IV	**Mechanical**	$		$ 98,163
V	**Electrical Assembly & Wiring**	$		$ 61,771
VI	**Buildings & Structures**	$		$ 65,136
VII	**Engineering & Plant Startup**	$		$ 47,438
	Subtotal I Though VII	$	$0	$ 640,408

		Unit	Value	Reference Value
VIII	**Contractor's Miscellaneous Cost**	$		$ 128,082
	Subtotal I Though VIII	$	$0	$ 768,490

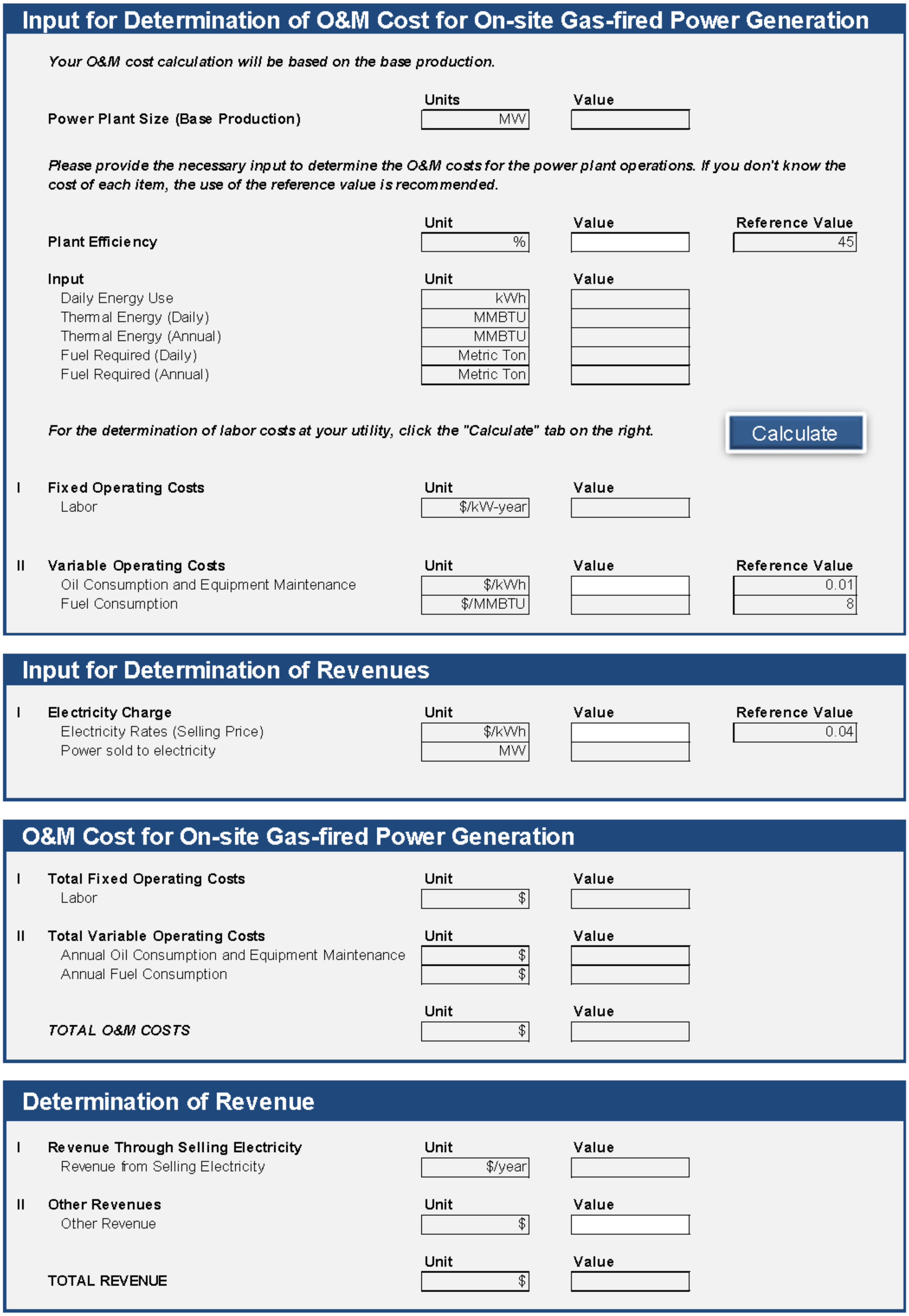
		Unit	Value	Reference Value
IX	**Owner's soft and Miscellaneous Cost**	$		$69,164

		Unit	Value
X	**Other Costs**	$	$ -

Capital Cost for On-site Gas-fired Power Generation

	Unit	Value
TOTAL CAPITAL COST	$	$0

Figure 4.8. Screenshot of the On-site Power Generation worksheets.



Input for Determination of O&M Cost for On-site Gas-fired Power Generation

Your O&M cost calculation will be based on the base production.

	Units	Value
Power Plant Size (Base Production)	MW	

Please provide the necessary input to determine the O&M costs for the power plant operations. If you don't know the cost of each item, the use of the reference value is recommended.

	Unit	Value	Reference Value
Plant Efficiency	%		45

Input	Unit	Value
Daily Energy Use	kWh	
Thermal Energy (Daily)	MMBTU	
Thermal Energy (Annual)	MMBTU	
Fuel Required (Daily)	Metric Ton	
Fuel Required (Annual)	Metric Ton	

For the determination of labor costs at your utility, click the "Calculate" tab on the right. Calculate

		Unit	Value	Reference Value
I	**Fixed Operating Costs**			
	Labor	$/kW-year		
II	**Variable Operating Costs**			
	Oil Consumption and Equipment Maintenance	$/kWh		0.01
	Fuel Consumption	$/MMBTU		8

Input for Determination of Revenues

		Unit	Value	Reference Value
I	**Electricity Charge**			
	Electricity Rates (Selling Price)	$/kWh		0.04
	Power sold to electricity	MW		

O&M Cost for On-site Gas-fired Power Generation

		Unit	Value
I	**Total Fixed Operating Costs**		
	Labor	$	
II	**Total Variable Operating Costs**		
	Annual Oil Consumption and Equipment Maintenance	$	
	Annual Fuel Consumption	$	
	TOTAL O&M COSTS	$	

Determination of Revenue

		Unit	Value
I	**Revenue Through Selling Electricity**		
	Revenue from Selling Electricity	$/year	
II	**Other Revenues**		
	Other Revenue	$	
	TOTAL REVENUE	$	

Figure 4.9. Screenshot of the On-site Power Generation worksheets.

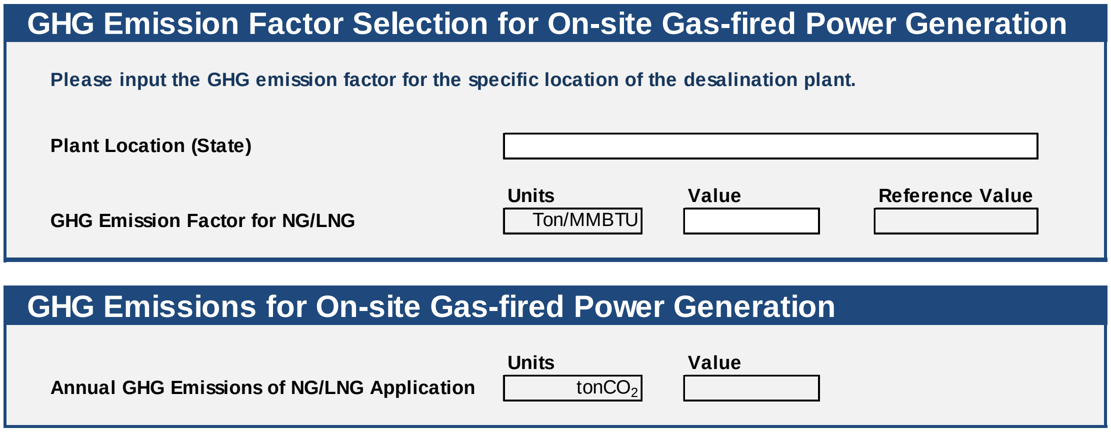


Figure 4.10. Screenshot of the On-site Power Generation worksheets.

4.3.7 Hybrid System Worksheets

The economic and environmental analysis of the hybrid option is conducted in four worksheets, as follows:

- Power requirements for high-pressure pumps, engine size selection, and grid capacity determination (Hybrid Power worksheet; Figure 4.11)
- Capital cost determination (Hybrid–CAP Worksheet; Figure 4.12, left)
- O&M cost determination (Hybrid–O&M Worksheet; Figure 4.12, right)
- GHG emissions evaluation (Hybrid–GHG Worksheet; Figure 4.13)

In the first ***Hybrid Power*** worksheet, the tool automatically calculates the engine size to run the high-pressure pumps and the capacity of the grid connection based on the average and peak demands, input in previous worksheets. The peak capacity is used as a basis for the capital cost calculation, whereas the base capacity is used to determine the O&M costs.

In the second ***Hybrid–CAP*** worksheet the necessary input for the calculation of the capital cost should be entered by the user in the appropriate cells. The worksheet is divided in two sub-spreadsheets: the first receiving the inputs and then calculating the capital costs for the gas engines to run the high-pressure pumps; and the second receiving the inputs and then calculating the capital costs for the grid connection of plants with gas-driven high-pressure pumps.

In the first spreadsheet that includes the calculation of the capital costs of the gas engines, all capital cost should be in dollars. If the user lacks the cost information for some or all the fields, the reference values can be used. The main elements included in the capital cost analysis for the gas engines that run the high-pressure pumps are the LNG regasification system (only if LNG is used as a preferred fuel option), the gas engine equipment, and other equipment. The reference values for the gas engine major equipment have been estimated using the cost curves previously developed in Chapter 4. For the additional element of the capital cost of the gas engines, the following costs have been applied:

- Civil—10% of the subtotal of the gas engines major equipment
- Mechanical—10% of the subtotal of the gas engines major equipment
- Electrical assembly and wiring—8% of the subtotal of the gas engines major equipment
- Building and structure—8% of the subtotal of the gas engines major equipment

- Engineering and plant startup—8% of the subtotal of the gas engines major equipment plus the civil, mechanical, electrical, building, and structure related costs
- Contractor's miscellaneous cost—15% of the subtotal of the gas engines major equipment plus the elements listed previously
- Owner miscellaneous cost—9% of the subtotal of the gas engines major equipment plus the elements listed previously

In the second spreadsheet that includes the calculation of the capital costs of the grid connection, all capital cost should be in dollars. If the user lacks the cost information for some or all the fields, the reference values can be used. The main elements included in the capital cost analysis for the grid connection of a hybrid system are the substation and the transmission costs. The reference values for the grid connection major equipment have been previously described in Chapter 4. For the additional element of the capital cost of the gas engines, the following costs have been applied:

- Permitting—20% of the subtotal of the equipment cost
- Civil—5% of the subtotal of the equipment cost
- Engineering and Design—5% of the subtotal of the equipment cost
- Electrical construction—5% of the subtotal of the equipment cost
- Startup test and commissioning—8% of the subtotal of the equipment cost
- Contractor's fee—10% of the subtotal of the equipment cost
- Owner miscellaneous cost—5% of the subtotal of the equipment cost

The reference values cannot be modified at the user's discretion. The user should leave the cell unchanged if that cell does not apply to the project.

On the basis of the input specified, the model automatically calculates the total capital cost for the hybrid system option.

In the second ***Hybrid–O&M*** worksheet, the necessary input for the calculation of the O&M costs should be entered by the user in the appropriate cells. The O&M cost calculation is based on the base plant production. The worksheet is divided in two sub-spreadsheets: the first receiving the inputs and then calculating the O&M costs for the gas engines to run the high-pressure pumps, and; the second receiving the inputs and then calculating the O&M costs for the grid connection of plants with gas-driven high-pressure pumps. The elements included in the O&M cost analysis are:

- Fixed operating costs (e.g., labor)
- Variable operating costs (for high-pressure pumps: oil consumption and equipment maintenance and LNG/NG fuel consumption; for grid electricity: energy charges and demand charges).

To calculate the unit labor cost for the total labor cost calculation, the user is directed to two supplementary spreadsheets within the *Labor—Hybrid Engines* and the *Labor—Hybrid Grid* worksheets by clicking the first and the second tab "Calculate," respectively. Details on the *Labor–Hybrid Engines* and the *Labor–Hybrid Grid* worksheets will be presented in the next sections.

In order to calculate the variable operation costs for the high-pressure pumps, the user should input the expected pump efficiency and the oil consumption and equipment maintenance unit cost, in addition to the energy costs assumptions that were provided in the *LCC Assumption* worksheet.

In order to calculate the variable operation costs for the grid connection, the tool uses the energy costs assumptions (energy charges and demand charges) that were provided in the *LCC Assumption* worksheet.

On the basis of the input specified, the model automatically calculates the total O&M costs for the hybrid system option.

In the fourth ***Hybrid–GHG*** worksheet, the necessary input for the calculation of the GHG emission should be entered by the user in the appropriate cells. The inputs required are the GHG emission factor for NG or LNG application and the GHG emission factor for the grid. The first is equal to 0.05306 ton/MMBTU as reported in Section 4.2. The GHG emission factor for the grid connection should be selected based on the location of the desalination plant. If the GHG emission factors are not provided by the electric utilities, regional average emission factors can be found in the eGrid tables (U.S. EPA, 2014).

On the basis of the input specified, the model automatically calculates the total GHG emissions for the hybrid system option.

Power Requirements for High Pressure Pumping

Based on the information provided, the required power to run your high pressure pumps is presented below.

Average Demand Basis	Units	Value
Total Energy Use by High Pressure Pumps	kWh	
Total Power Required to Run the High Pressure Pumps	MW	

Peak Demand Basis	Units	Value
Total Energy Use by High Pressure Pumps	kWh	
Total Power Required to Run the High Pressure Pumps	MW	

Engine Size Selection and Grid Capacity

Based on the information provided, the engine size and grid capacity is presented below.

Peak Production	Units	Value
Engine Size to run High Pressure Pumps	MW	
Grid Capacity	MW	

Average Production	Units	Value
Engine Size to run High Pressure Pumps	MW	
Grid Capacity	MW	

Figure 4.1.1. Screenshot of the Hybrid Power worksheet.

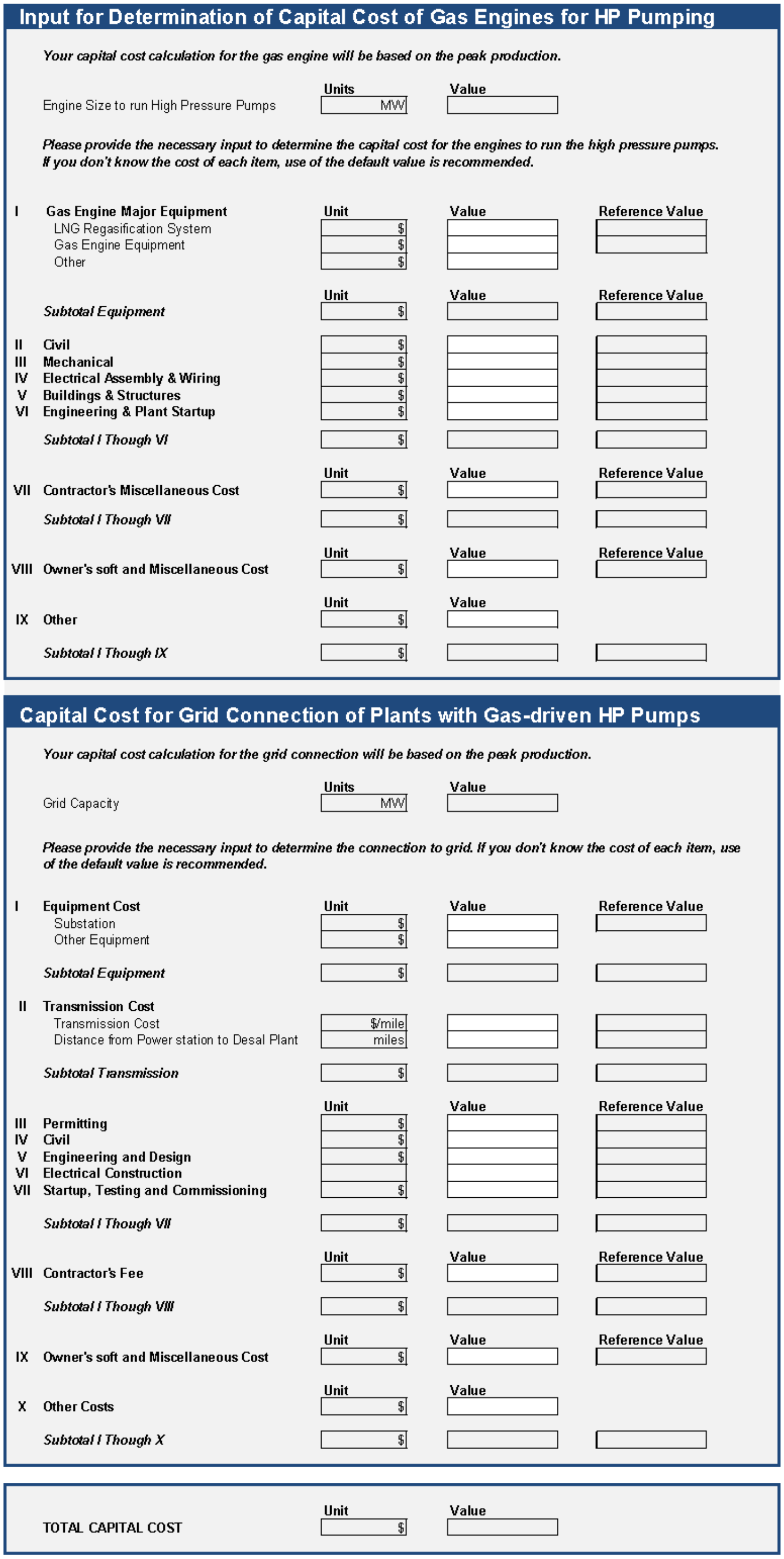
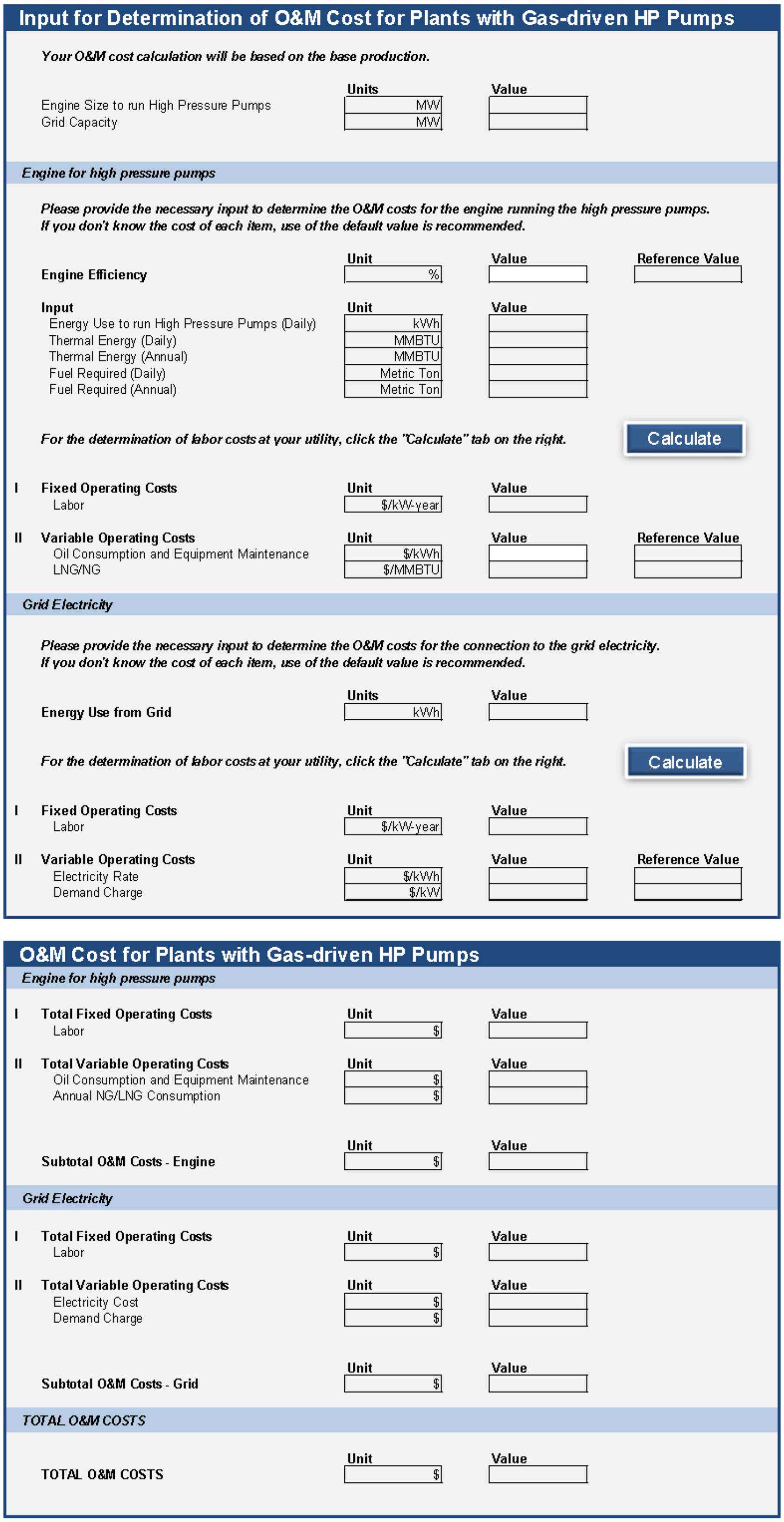


Figure 4.12. Screenshot of the Hybrid–CAP and Hybrid–O&M worksheets



Input for Determination of O&M Cost for Plants with Gas-driven HP Pumps

Your O&M cost calculation will be based on the base production.

	Units	Value
Engine Size to run High Pressure Pumps	MW	
Grid Capacity	MW	

Engine for high pressure pumps

Please provide the necessary input to determine the O&M costs for the engine running the high pressure pumps.
If you don't know the cost of each item, use of the default value is recommended.

	Unit	Value	Reference Value
Engine Efficiency	%		

Input	Unit	Value
Energy Use to run High Pressure Pumps (Daily)	kWh	
Thermal Energy (Daily)	MMBTU	
Thermal Energy (Annual)	MMBTU	
Fuel Required (Daily)	Metric Ton	
Fuel Required (Annual)	Metric Ton	

For the determination of labor costs at your utility, click the "Calculate" tab on the right. Calculate

		Unit	Value	Reference Value
I	**Fixed Operating Costs**	Unit	Value	
	Labor	$/kW-year		
II	**Variable Operating Costs**	Unit	Value	Reference Value
	Oil Consumption and Equipment Maintenance	$/kWh		
	LNG/NG	$/MMBTU		

Grid Electricity

Please provide the necessary input to determine the O&M costs for the connection to the grid electricity.
If you don't know the cost of each item, use of the default value is recommended.

	Units	Value
Energy Use from Grid	kWh	

For the determination of labor costs at your utility, click the "Calculate" tab on the right. Calculate

		Unit	Value	Reference Value
I	**Fixed Operating Costs**	Unit	Value	
	Labor	$/kW-year		
II	**Variable Operating Costs**	Unit	Value	Reference Value
	Electricity Rate	$/kWh		
	Demand Charge	$/kW		

O&M Cost for Plants with Gas-driven HP Pumps

Engine for high pressure pumps

		Unit	Value
I	**Total Fixed Operating Costs**	Unit	Value
	Labor	$	
II	**Total Variable Operating Costs**	Unit	Value
	Oil Consumption and Equipment Maintenance	$	
	Annual NG/LNG Consumption	$	
		Unit	Value
	Subtotal O&M Costs - Engine	$	

Grid Electricity

		Unit	Value
I	**Total Fixed Operating Costs**	Unit	Value
	Labor	$	
II	**Total Variable Operating Costs**	Unit	Value
	Electricity Cost	$	
	Demand Charge	$	
		Unit	Value
	Subtotal O&M Costs - Grid	$	

TOTAL O&M COSTS

	Unit	Value
TOTAL O&M COSTS	$	

Figure 4.12. Screenshot of the Hybrid–CAP and Hybrid–O&M worksheets (continued)

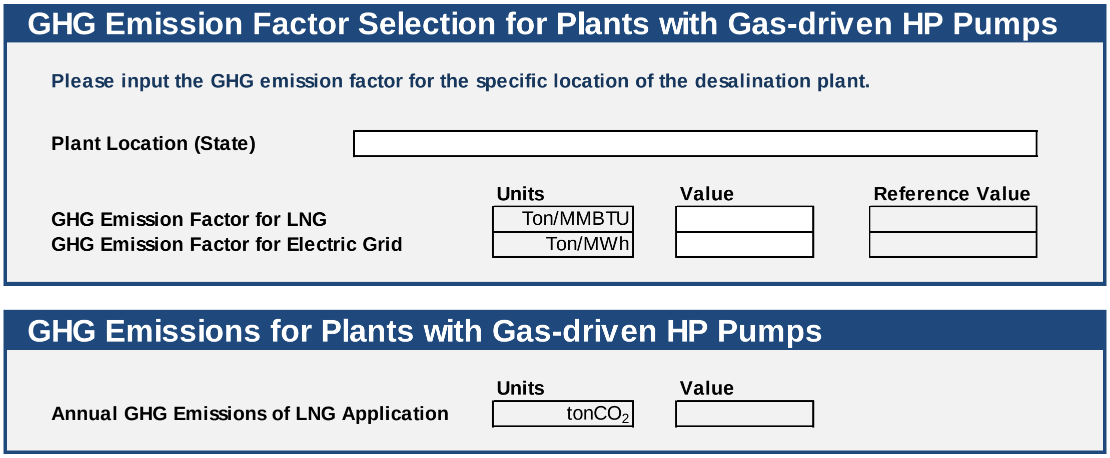


Figure 4.13. Screenshot of the Hybrid-GHG worksheet.

4.3.8 Grid Electricity Worksheets

The economic and environmental analysis of the grid electricity option is conducted in three worksheets, as follows:

- Capital cost determination (Grid–CAP Worksheet; Figure 4.14)
- O&M cost determination (Grid–O&M Worksheet; Figure 4.15)
- GHG emissions evaluation (Grid–GHG Worksheet; Figure 4.16)

In the first ***Grid—CAP*** worksheet the necessary input for the calculation of the capital cost should be entered by the user in the appropriate cells. In this spreadsheet all capital cost should be in dollars. If the user lacks the cost information for some or all of the fields, the reference values can be used. The main elements included in the capital cost analysis for the grid connection of a hybrid system are the substation and the transmission costs. The reference values for the grid connection major equipment were described in Chapter 4. For the additional element of the capital cost of the gas engines, the following costs have been applied:

- Permitting—20% of the subtotal of the equipment cost
- Civil—5% of the subtotal of the equipment cost
- Engineering and design—5% of the subtotal of the equipment cost
- Electrical construction—5% of the subtotal of the equipment cost
- Startup test and commissioning—8% of the subtotal of the equipment cost
- Contractor's fee—10% of the subtotal of the equipment cost
- Owner miscellaneous cost—5% of the subtotal of the equipment cost

The reference values cannot be modified at the user's discretion. The user should leave the cell unchanged if that cell does not apply to the project.

On the basis of the input specified, the model automatically calculates the total capital cost for the hybrid system option.

In the second ***Grid–O&M*** worksheet the necessary input for the calculation of the O&M costs should be entered by the user in the appropriate cells. The O&M cost calculation is based on the base plant production. The elements included in the O&M cost analysis for the grid connection are:

- Fixed operating costs (e.g., labor)
- Variable operating costs (energy charges and demand charges)

To calculate the unit labor cost for the total labor cost calculation, the user is directed to the supplementary *Labor–Grid* worksheet by clicking the tab “Calculate.” Details on the *Labor–Grid* worksheet will be presented in the next sections.

In order to calculate the variable operation costs for the grid connection, the tool uses the energy costs assumptions (energy charges and demand charges) that were provided in the *LCC Assumption* worksheet.

On the basis of the input specified, the model automatically calculates the total O&M costs for the grid electricity connection option.

In the fourth ***Grid–GHG*** worksheet the necessary input for the calculation of the GHG emission should be entered by the user in the appropriate cells. The input required is the GHG emission factor for the grid. The GHG emission factor for the grid connection should be selected based on the location of the desalination plant. If the GHG emission factors are not provided by the electric utilities, regional average can be found in the eGrid tables (U.S. EPA, 2014).

On the basis of the input specified, the model automatically calculates the total GHG emissions for the hybrid system option.

Input for Determination of Capital Cost for a Grid Connection

Your capital cost calculation will be based on the peak production.

	Units	Value
Grid Capacity (Peak Production)	MW	

Please provide the necessary input to determine the capital costs for the grid connection to the desalination plant. If you don't know the cost of each item, use of the default value is recommended.

		Unit	Value	Reference Value
I	**Equipment Cost**			
	Substation	$		
	Other Equipment	$		
	Subtotal Equipment	$		
II	**Transmission Cost**			
	Transmission Cost	$/mile		
	Distance from Power Station to Desal Plant	miles		
	Subtotal Transmission	$		

		Unit	Value	Reference Value
III	Permitting	$		
IV	Civil	$		
V	Engineering and Design	$		
VI	Electrical Construction			
VII	Startup, Testing, and Commissioning	$		
	Subtotal I Though VII	$		

		Unit	Value	Reference Value
VIII	Contractor's Fee	$		
	Subtotal I Though VIII	$		

		Unit	Value	Reference Value
IX	Owner's soft and Miscellaneous Cost	$		

		Unit	Value
X	Other Costs	$	

Capital Cost for a Grid Connection

	Unit	Value
TOTAL CAPITAL COST	$	

Figure 4.14. Screenshot of the Grid–CAP worksheet.

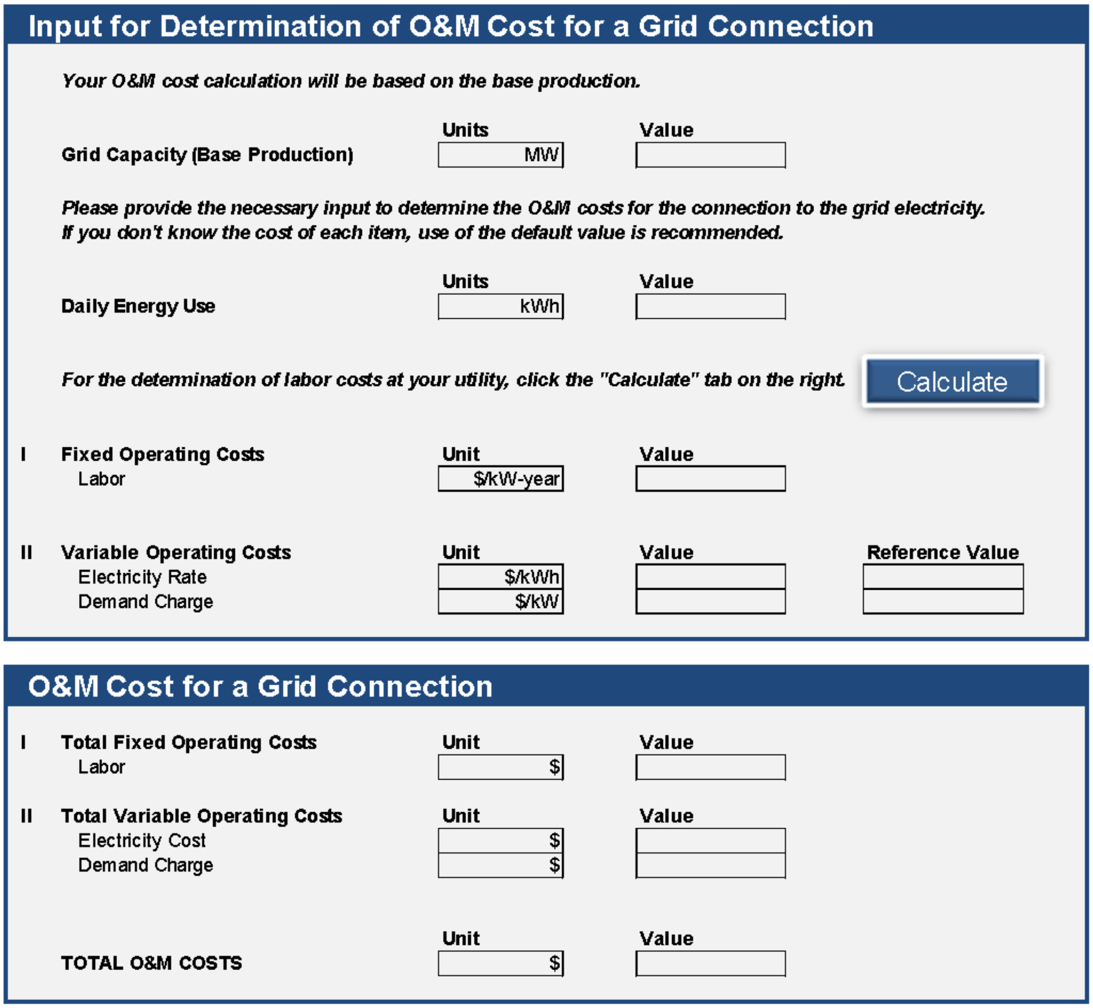


Figure 4.15 Screenshot of the Grid–O&M worksheet.

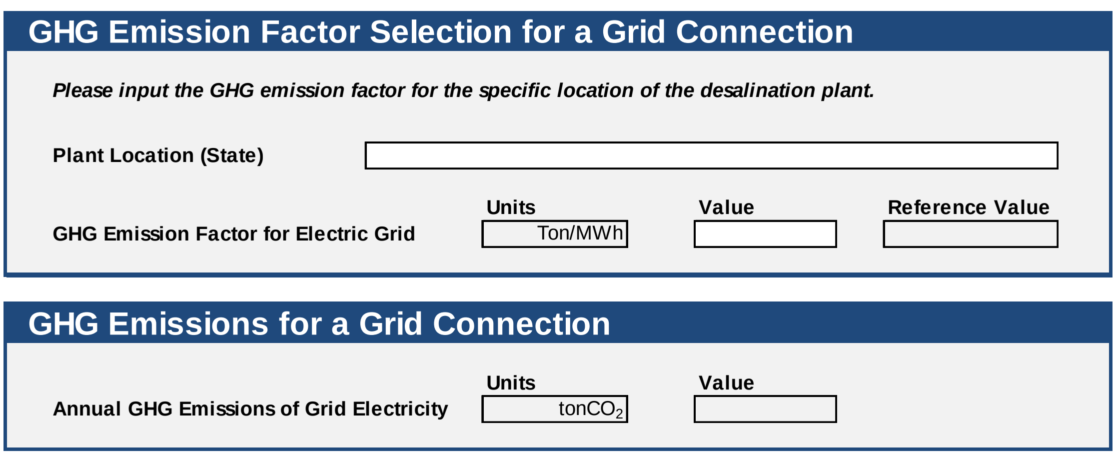


Figure 4.16. Screenshot of the Grid–GHG worksheet.

4.3.9 Labor Worksheets

The calculation of the unit labor costs is facilitated by the use of dedicated spreadsheets, an example of which is found in Figure 4.17. The user should input the number of employees, related hourly rates, and weekly hours of operation of dedicated staff, including supervisor, engineers, technicians, and others. The user should also input the overhead percentage for the labor hours considered. The spreadsheet automatically calculates the cost per year of each personnel and the total labor cost.

The value reported in the blue cell, is the value of the unit cost of labor, which is going to be automatically reported in the O&M spreadsheet.

Please fill the table below to determine the $/kW-year for the labor cost calculation.

	Unit	Value
Overhead	%	

	Rate	No of Employees	Hrs/week	Hours/year	Cost/year
	$/hr	-	hr/week	hr/year	$/year
Supervisor					
Engineer					
Technician					
Other					

	Unit	Value
Total	$/year	
Labor	$/kW-year	

The number obtained in the "blue cell" will be input as your labor unit cost.

Figure 4.17. Screenshot of the Labor worksheet.

For this study, different assumptions used to account for labor qualifications and hourly rates were made. In particular, the following were considered:

- For the on-site power generation option, a supervisor (for only 10 hours per week), a full-time engineer, and a full-time technician were considered and the respective hourly rates were $65, $40, and $25.
- For the LNG/NG engines of the hybrid system option, a supervisor (for 2 hours per week), an engineer (for 10 hours per week), and a technician (for 10 hours per week) were considered and the respective hourly rates were $65, $40, and $25.
- For the grid connection of the hybrid system option, an engineer (for 5 hours per week) and a technician (for 10 hours per week) were considered and the respective hourly rates were $40 and $25.
- For the grid connection option, an engineer (for 5 hours per week) and a technician (for 10 hours per week) were considered and the respective hourly rates were $40 and $25.

4.3.10 Final Outputs

The final output of the software tool summarizes the information obtained in the previous worksheets and introduces new LCC cost, LCOE, and life cycle GHG emissions calculations for the alternative(s) selected. In particular, the final output worksheet includes:

- Scenarios selected for analysis
- Power plant, engine sizes, and grid capacity for the alternative selected
- First year costs for the alternative selected
- Capital and O&M LCC for the alternative selected
- LCOE for the alternative selected
- First year and life cycle GHG emissions

An example of the **Output** worksheet that includes all three power supply alternatives is presented in Figure 4.18. The output results allow the user to compare side by side the results of the different alternatives and allow the user to choose the best fitting alternative based on the desired metric: energy savings, GHG emission reductions, and/or economic viability.

These results can be saved and printed.

Project Information

Project Name	
Project Description	
Utility	
Contact Person	

Desalination Plant Information

Plant Name	
Location	
Desalination Process Type	
Plant Implementation Status	
Year Built	

	Units	Value
Desalination Plant Peak Capacity	MGD	
Desalination Plant Average Capacity	MGD	
Influent Water Temperature	°F	
Influent Water Total Dissolved Solids	mg/L	

Energy Use and Power Plant Size

Power Source #1	On-site Gas-fired Power Generation	
Power Source #2	Hybrid System	
Power Source #3	Grid Electricity	

	Units	Power Source #1	Power Source #2	Power Source #3
Total Unit Power Use	kWh/kgal			
Total Daily Energy Use	kWh			
Power Source #1		**Power Source #1**	**Power Source #2**	**Power Source #3**
Excess Power	MW		Not Applicable	Not Applicable
Total Power Plant Size	MW		Not Applicable	Not Applicable
Power Plant Configuration			Not Applicable	Not Applicable
Power Source #2		**Power Source #1**	**Power Source #2**	**Power Source #3**
Engine Size	MW	Not Applicable		Not Applicable
Grid Capacity	MW	Not Applicable		Not Applicable
Power Source #3		**Power Source #1**	**Power Source #2**	**Power Source #3**
Grid Capacity	MW	Not Applicable	Not Applicable	

Life Cycle Cost Analysis

First Year Cost	Units	Power Source #1	Power Source #2	Power Source #3
Capital Cost	$			
Capital Cost per kW	$/kW			
O&M Costs	$			
O&M Costs per kW	$/kW			
Total Cost	$			
Total Cost per kW	$/kW			
Life Cycle Cost	**Units**	**Power Source #1**	**Power Source #2**	**Power Source #3**
Life Cycle Capital Cost (Present Value)	$			
Life Cycle Capital Cost per Unit Energy (Present Value)	$/kW			
Life Cycle O&M Cost (Present Value)	$			
Life Cycle O&M per Unit Energy (Present Value)	$/kW			
Total Life Cycle Cost	$			
Life Cycle Cost per Unit Energy (Present Value)	$/kW			

Levelized Cost of Energy Analysis

	Units	Power Source #1	Power Source #2	Power Source #3
Levelized Cost of Energy	$			

GHG Emissions Analysis

	Units	Power Source #1	Power Source #2	Power Source #3
Annual GHG Emissions	$tonCO_2$			
Life Cycle GHG emission	$tonCO_2$			

Figure 4.18. Screenshot of the Output worksheet when selecting all three alternative power supply options.

Chapter 5

Economic and Environmental Evaluation of LNG Versus Grid Electricity: Conceptual Case Studies and Sensitivity Analysis

This chapter compares the economic feasibility and GHG emissions potential of the application of LNG/NG and the electricity provided by the grid supply. The specific comparisons are based on:

- Total costs (capital and O&M costs) in the first year of operation
- LCC (capital and O&M LCC)
- Levelized cost of energy
- GHG emissions (first year and life cycle)

This comparison was performed for desalination plants of various sizes (from 2.5 to 150 MGD) and two fuel options (NG vs. LNG).

5.1 Comparative Economic and Environmental Evaluation of LNG Versus the Grid

A number of assumptions were made as a basis for the comparative evaluation and are reported in Table 6.1. In this comparative economic assessment, we assumed that the size of the power plant is designed to only satisfy the power requirements of the desalination plant and no excess power is produced (e.g., to be sold to the electric utility). Current market values for NG and LNG have been used and typical electric and demand charges applied. For the on-site power generation option, the capital costs do not include any cost related to the land acquired to build the power plant because these cost components are fundamentally site specific and can only be analyzed on a case-by-case basis.

It is important to note that the findings from this evaluation are valid and meaningful primarily in relation to the assumption employed.

Table 5.1. Assumptions Used for the Economic and Environmental Comparative Analysis

Parameter	Units	Value
General		
Peaking factor	-	1.5
Plant efficiency (Simple cycle)	%	45
Plant efficiency (Combined cycle)	%	50
HP pump efficiency	%	45
Life Cycle Assumptions		
Period	Years	25
Initial Year of Operations	-	2017
Year of Analysis	-	2015
Cost Assumptions		
Cost estimate dollar basis year	-	2015
Construction cost escalation	% (Annual)	3.50%
O&M and general cost escalation	% (Annual)	3.00%
Financial Assumptions		
Capital Treatment	-	D/S
Financing interest rate	%	5.25%
Financing maturity	Years	25
Financing costs, capitalized	%	2.00%
Debt structure	Annual	Equal
Bond reserve	%	0.00%
Economic Assumptions		
Discount rate (cost of capital)	%	5.25%
Annual growth in electricity consumption	%	2.00%
GHG Emission Factors		
LNG/NG Emission Factor	ton/MMBTU	0.05306
Grid Emission Factor (PG&E)	tonsCO_2/MWh	0.177
eGrid Emission Factor (National Average)	tonsCO_2/MWh	0.620
Fuel and Electricity Charges Assumptions		
Electricity Rates (Purchase)	$/kWh	0.08
Demand Charge (purchase)	$/kW	10
Fuel Purchase (for LNG)	$/MMBTU	8
Fuel Purchase (for NG)	$/MMBTU	3
Oil consumption and maintenance	$/kWh	0.01

5.1.1 First Year Capital and O&M Cost Comparison

This section presents the comparison of the three power supply alternatives based on the Capital and O&M costs for desalination plants of sizes ranging from 2.5 to 150 MGD. The analysis was conducted for 13 individual sizes (2.5, 5, 10, 25, 30, 35, 50, 65, 75, 85, 100, 125, and 150 MGD). In addition, the detailed breakdown of all cost elements for all sizes is presented for a reference case (50 MGD desalination plant) selected to illustrate relative distribution of different cost elements.

5.1.1.1. Comparison Summary

Capital and O&M costs for the first year of operation were calculated for desalination plants of sizes ranging from 2.5 MGD to 150 MGD powered by any of the three alternatives proposed: the on-site power generation, the hybrid system or the grid electricity connection.

Figure 5.1 shows the comparative capital cost analysis for these three options. From the results it is clear that for desalination plant sizes above 10 MGD, the grid electricity requires lower capital investments than the LNG-based options, and the gap in total capital cost between the different options increases with increasing plant size.

Figure 5.2 shows the comparative O&M cost analysis for these three options. Opposite to what was observed for the capital investment, from an O&M cost perspective, the LNG-based options appear to be the best solution for desalination plants of capacity above 10 MGD. The gap in total capital cost between the different options increases with increasing plant size.

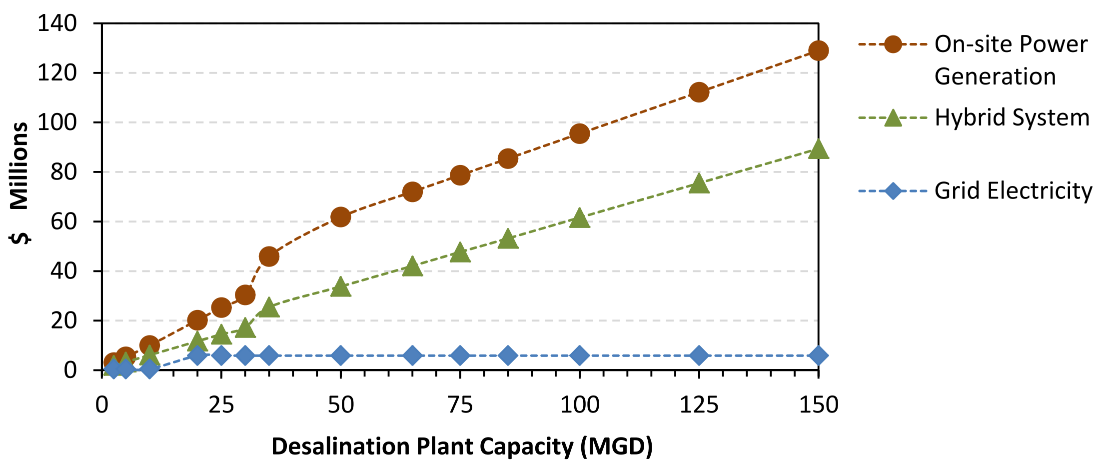


Figure 5.1. Total capital costs for on-site power generation, hybrid system, and grid electricity connection options for desalination plants of various sizes.

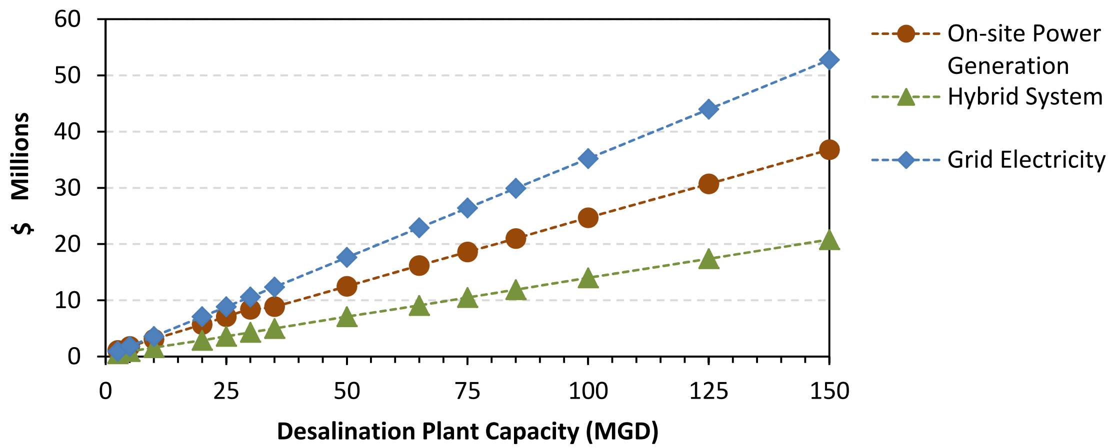


Figure 5.2. Total O&M Costs for on-site power generation, hybrid system and grid electricity connection options for desalination plants of various sizes.

5.1.1.2. Reference Case

This section includes the comparative analysis of the first year capital costs and O&M costs for two LNG options (on-site power generation and hybrid system) and for the connection to the grid electricity of a 50 MGD desalination plant. The capital and O&M cost estimates for each of these options were based on the assumptions listed in Table 5.1. Briefly, these cost estimates include different elements depending on the power source considered. A description of these elements is presented in Section 5.3.

Figure 5.3 shows the breakdown of the capital costs for the on-site power generation, the grid connection option, and the hybrid system, respectively. For the on-site 33 MW power generation option that supplies power to the 50 MGD desalination plant, a high share of the capital cost is for the special equipment that compose a combined cycle configuration, which includes the LNG regasification system, the gas and steam turbines package, the heat recovery system, and so on. The contractor and owner's soft miscellaneous costs are the other major expenses that follow the equipment cost, respectively. In addition, expenses related to the total project engineering, procurement, and construction costs accounted for approximately 20% of the total capital cost.

Similarly, the equipment cost for both the hybrid system and the grid connection options represent approximately 50% of the total capital expenses. For the grid electricity option, the capital investments include the cost for the substation, on-site transformers, and inter connections. These capital costs do not include any potential cost for land acquired for the power plant site in the on-site power generation option or the transmission costs of a grid electricity connection.

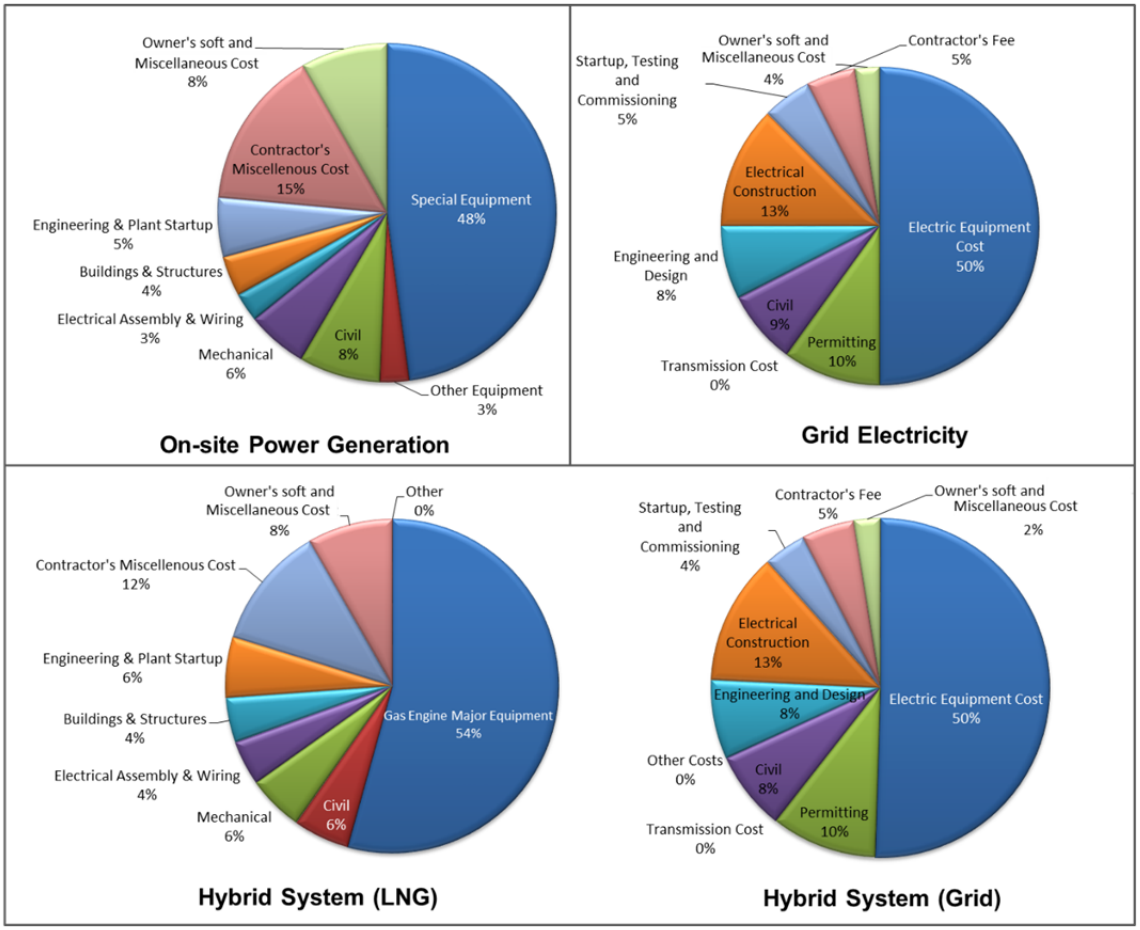


Figure 5.3. Breakdown of capital costs for on-site gas fired power generation, a grid connection, and a hybrid system for a 50 MGD desalination plant.

Figure 5.4 shows the breakdown of the O&M costs for the on-site power generation, the hybrid system, and the grid electricity connection option that supply power to the 50 MGD desalination plant. For the on-site power generation and the hybrid system that are based on LNG use, approximately 80% of the total O&M costs are associated with the cost of fuel consumed. The majority of the O&M costs for the grid electricity option are represented by the electricity cost (85%) and partially by the related demand charges (15%). The demand charge also represents 20% of the O&M costs of the hybrid system alternative. The cost of labor is minimal compared to the previously mentioned costs and accounts for <3% of the total O&M costs for the three options evaluated.

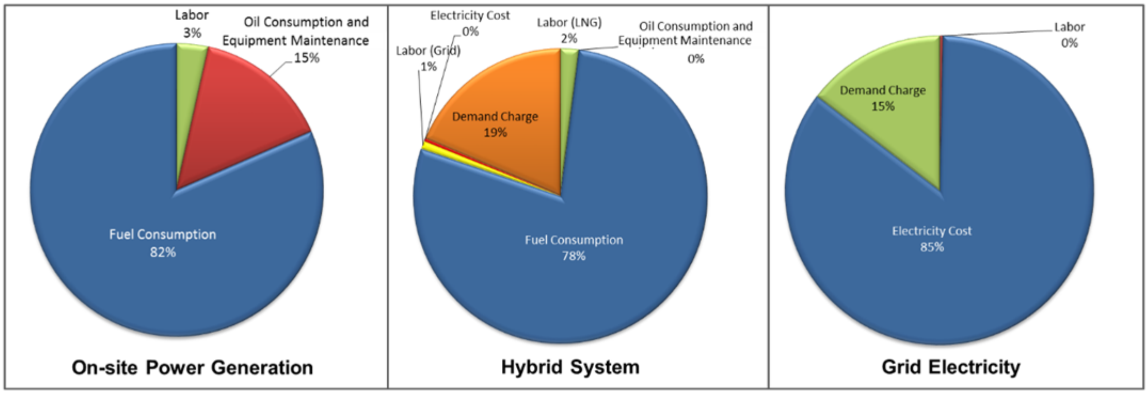


Figure 5.4. Breakdown of O&M costs for on-site gas fired power generation, a hybrid system, and a grid connection for a 50 MGD desalination plant.

5.1.2 Life Cycle Cost

Figure 5.5 shows the breakdown of the life-cycle capital and O&M costs for an on-site power generation facility driven by LNG for desalination plants of various sizes. The results show that the life cycle O&M costs increase over time at a greater extent than the life cycle capital costs and represent the highest share of the total LCC for this option. Life cycle O&M costs are also the major cost if a grid connection alternative is selected (Figure 5.6); however, for this specific option, a lower impact on the life cycle capital costs is observed.

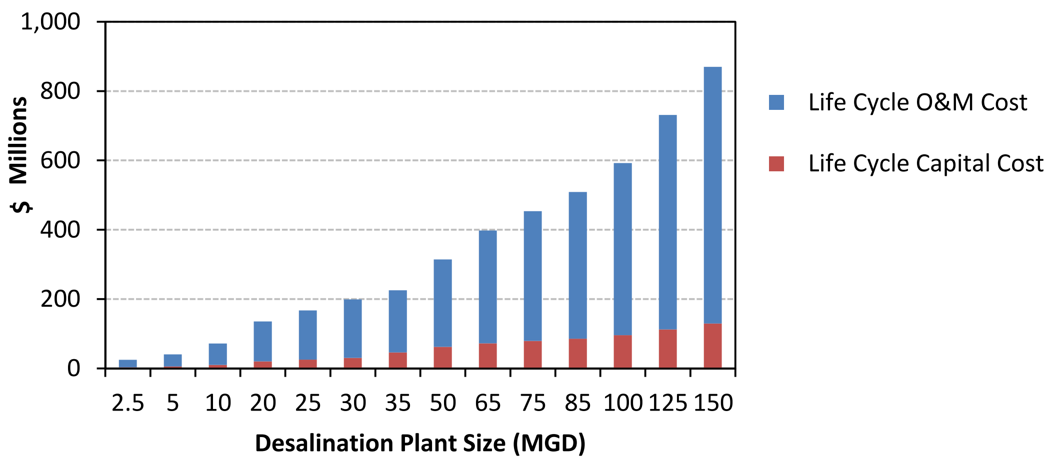


Figure 5.5. Break down of capital and O&M life cycle capital costs for an on-site power generation option for desalination plants of various sizes.

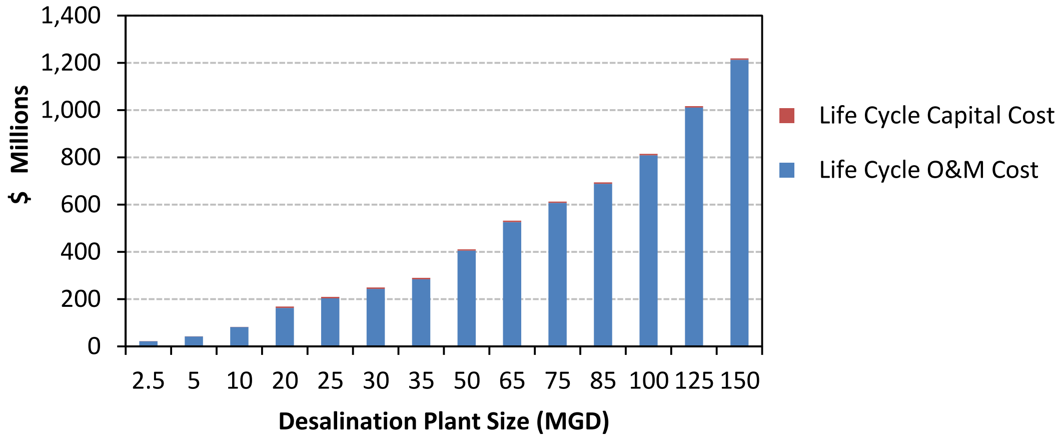


Figure 5.6. Break down of capital and O&M life cycle capital costs for a grid connection option for desalination plants of various sizes.

The comparative total LCC analysis presented in Figure 5.7 shows that the LNG on-site generation alternative yields lower total LCC than the hybrid system and of the grid electricity connection for desalination plant sizes that are higher than 20 MGD. For instance:

- For desalination plants from 20 MGD to 150 MGD, the LCC of the on-site power generation option is between 20% and 30% lower than that of the grid connection;
- For plant sizes smaller than 20 MGD, the LCC for the grid option and that of on-site generation are comparable and could be within 5 to 13% difference.

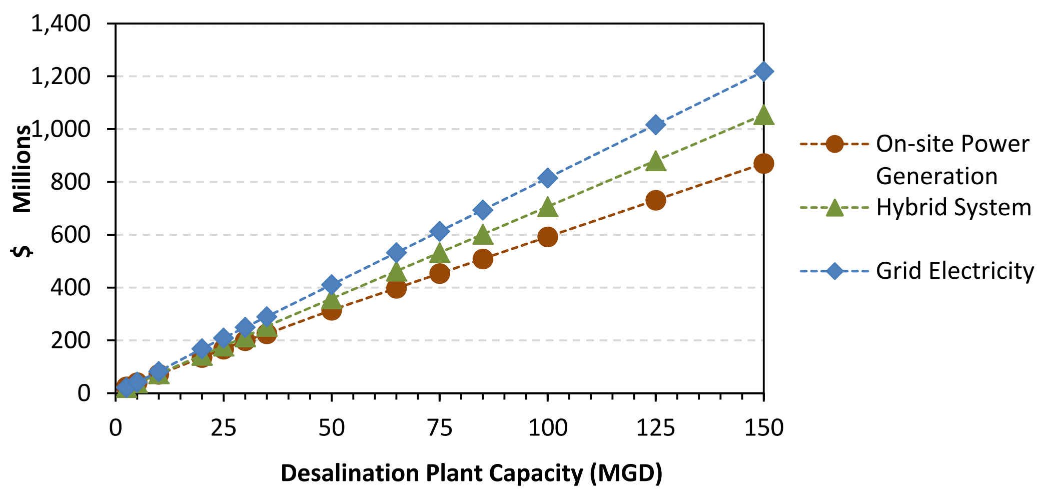


Figure 5.7. Total life cycle capital costs for an on-site power generation, hybrid system, and grid electricity connection for desalination plants of various sizes.

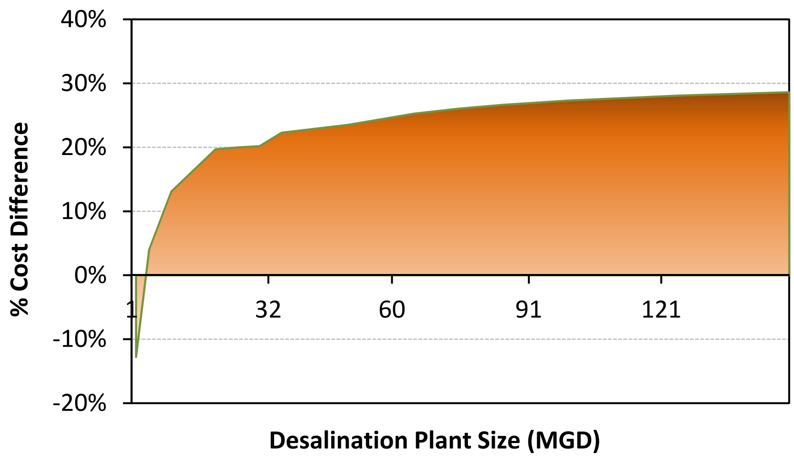


Figure 5.8. Total LCC difference from the grid electricity option to the on-site power generation.

5.1.3 Levelized Cost of Energy

In this study, the LCOE analysis has been performed to compare the cost of energy generated by the different power source options for desalination plants of various sizes. In Figure 5.9, the LCOE of the different power source alternatives for desalination plant sizes ranging from 2.5 to 150 MGD are reported. The results of the LCOE analysis show that

- For on-site power generation systems, the LCOE decreases from 19 to 11 cents/kWh with increasing size of the desalination plant from 2.5 to 150 MGD;
- For LNG-based hybrid systems, the LCOE decreases from 17 to approximately 14 cents/kWh with increasing size of the desalination plant from 2.5 to 150 MGD; and
- For the grid electricity, the LCOE is slightly affected by the desalination plant size with values between 16 to 17 cents/kWh.

Therefore, the LCOE analysis performed to compare the cost of energy generated by the different power source options showed that for desalination capacities of 10 MGD and higher, the LNG based on-site power generation is the lowest-cost option among all the power supply alternatives evaluated. The hybrid systems also show a lower LCOE than the grid alternative for desalination plants of capacity higher than 5 MGD.

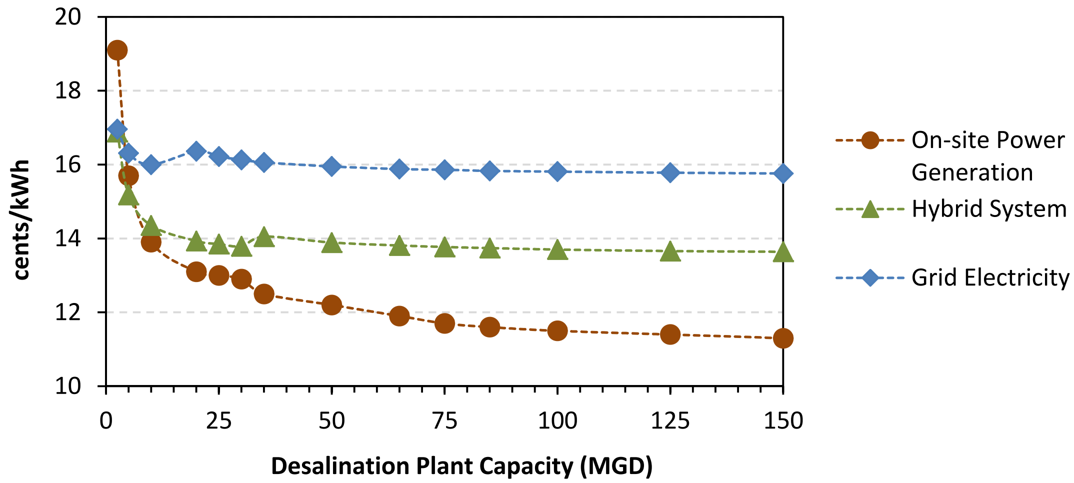


Figure 5.9. Levelized cost of energy for the on-site power generation, hybrid system, and grid electricity connection for desalination plants of various sizes.

5.1.4 Life Cycle GHG Emissions

The power source alternatives considered in this study were also compared based on their potential to generate GHG emissions over the project life time. GHG emissions arise from electricity usage and from the possible use of alternative fuels, such NG or LNG. The GHG emitted from energy usage is directly dependent on the energy utilization and the GHG emission factor per unit energy consumed selected. It should be noted that the GHG emissions from electricity use are a Scope 2 (indirect) type of emission, whereas the emissions from the LNG use are considered as Scope 1 (direct) emission. Therefore, the accounting methodologies and site-specific regulations are different. Accuracy in reporting GHG emissions is directly dependent on the accuracy of the activity data (e.g., energy or fuel use) as well as the accuracy of the associated GHG emission factors per unit energy/fuel consumed.

For both the grid electricity option and the grid connection of the hybrid alternative considered in this study, two emission factors have been tested to cover two extreme emission scenarios:

- U.S. EPA eGRID national average emission factor of 0.620 tonCO2 eq/MWh (U.S. EPA, 2014);
- Estimated future emissions by Pacific Gas & Electric, an electric utility in California, based on a model that forecasts the emission factors depending on how the electricity sector would reduce emissions under AB32 (0.177 tonsCO2/MWh for the 2015 scenario).

Figure 5.10 shows the life cycle GHG emissions for the different power source options tested and for various desalination plant sizes. Given the assumptions presented in Table 5.1, the selection of the emission factor for the power grid largely influences the results. When low GHG emission factors are used, such as estimated by PG&E, the grid electricity option results in lower life-cycle GHG emissions than those of other power source alternatives. For United States national average emission factors, the opposite is observed and the LNG-based on-site power generation appears to be the most sustainable option.

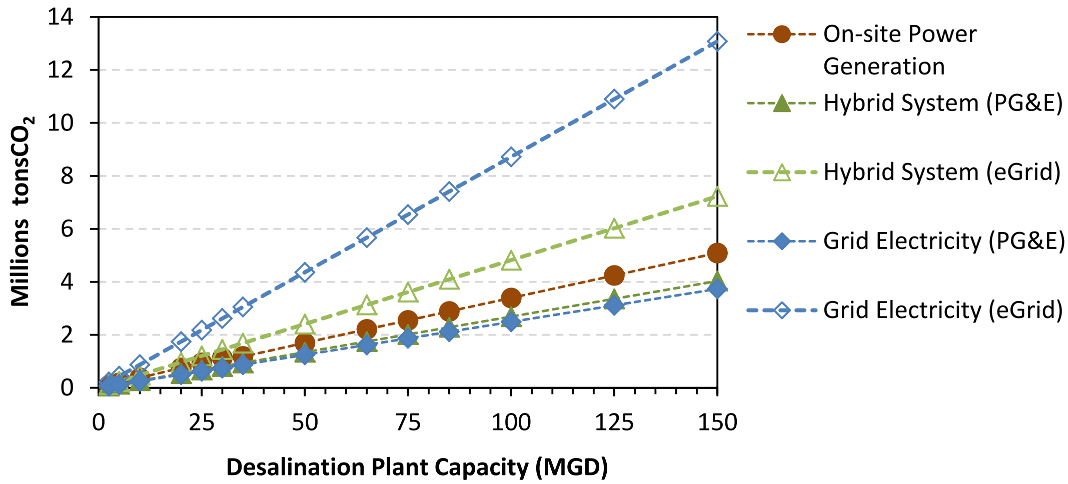


Figure 5.10. Life cycle GHG emissions from the on-site power generation, hybrid system, and grid electricity connection options for desalination plants of various sizes.

5.2 Comparison of LNG Versus NG

An economic comparison was developed between LNG and NG options to power desalination plants of sizes between 2.5 MGD to 150 MGD. The analysis takes into account differences in equipment used, which affects the capital costs as well as the cost of the NG and LNG fuels that were included in the O&M cost analysis. Compared to NG-based options, power generation plants or gas engines that use LNG need additional equipment, the regasification system, to revaporize the LNG into gas for use. The capital cost of a regasifier was calculated based on a $60/kW, as previously reported in Chapter 4. Differences in O&M costs were due to differences in fuel prices considered in this study ($3/MMBTU for NG and $8/MMBTU for LNG). The cost of LNG considered in this study is not inclusive of the inland transportation cost of the fuel from the LNG terminal to the desalination plant site, which is site-specific.

All these elements have an impact on the total LCC for an LNG-based versus a NG-based system, as shown in Figure 5.11. As the figure shows, the total LCC of the LNG-based on-site power generation system is 43% to up to 86% higher than the NG-based counterpart for desalination plant sizes that increase progressively from 2.5 MGD to 150 MGD. For hybrid systems, the total LCC of the LNG-based hybrid system is approximately between 20 and 26% higher than the NG-based counterpart for desalination plant sizes between 2.5 MGD and 150 MGD.

The fuel selected also impacts the LCOE analysis, as shown in Figure 5.12. As for the LCC, the LCOE is higher for the use of LNG and lower when NG is selected.

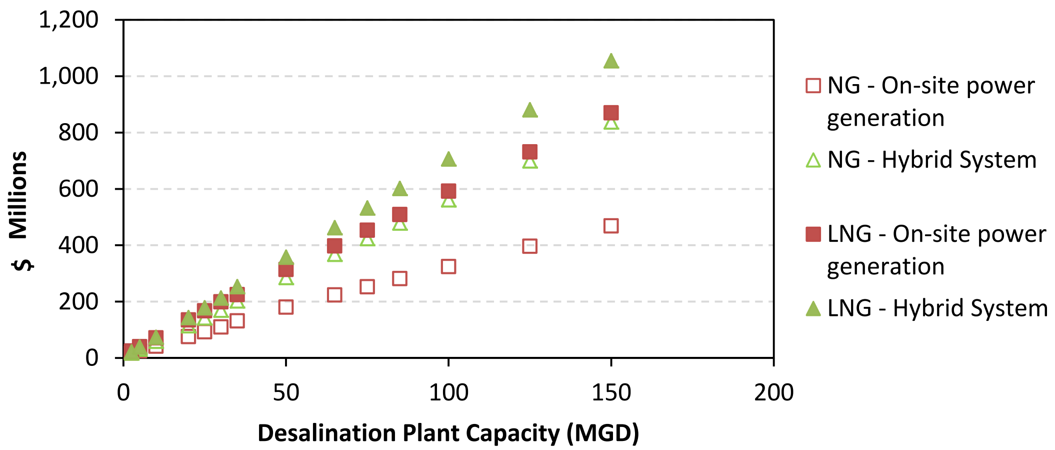


Figure 5.11. Comparison of total LCC of on-site power generation and hybrid system options using LNG and NG for desalination plants of various sizes.

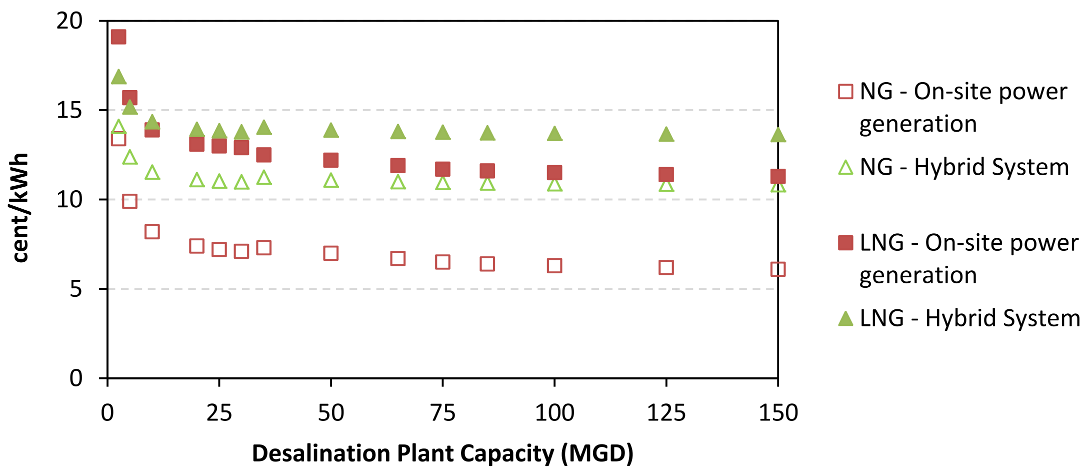


Figure 5.12. Comparison of levelized cost of energy of on-site power generation and hybrid system options using LNG and NG for desalination plants of various sizes.

5.3 Conceptual Case Studies and Sensitivity Analysis

Two conceptual case studies of a mid-range capacity seawater desalination plants (25 and 50 MGD) were developed to compare the economics of LNG-powered and grid electricity-powered desalination and to conduct sensitivity analyses on a set of economic parameters specific to a region.

First year capital and O&M costs and their related life-cycle costs of the three alternative power sources for 25 and 50 MGD desalination plants were determined, and the results were reported in Tables 5.2 and 5.3, respectively. The results show that although during the first year the grid electricity generates lower total cost per unit energy than the LNG-based alternatives, the life-cycle analysis shows that the LNG power generation and the hybrid system are more economically beneficial options, as also demonstrated by the lowest LCOE obtained. For the LNG power generation system, the capital costs in the first year represent approximately 80% of the total costs, however in the life cycle analysis, they only represent 15 to 20% of the total LCC. For the grid system, the capital costs in the first year represent approximately 25 to 40% of the total costs; however, in the life cycle analysis, they only represent 1 to 3% of the total LCC. These percentages show that the majority of the costs in a life cycle analysis are represented by the O&M expenditures.

Tables 5.2 and 5.3 also show the life cycle GHG emissions by all the alternatives considered. It is clear that the extent of GHG emitted is dependent on the emission factor used for analysis. Lower emission factors, such those used by PG&E for water utilities in California, make the grid electricity option the most sustainable among the LNG-based alternatives from a life cycle perspective. For higher emission factors, such those issued by the eGrid, the opposite is true, and LNG power generation yields the lowest amount of GHG emissions.

Table 5.2. Capital, O&M Costs, and GHG Emissions from Different Power Source Alternatives for Desalination Plants of 25 MGD Size

	LNG Power Generation	Hybrid System	Grid Electricity
LNG-Power Generation Capacity (MW)	16	8	N/A
Grid Capacity (MW)	N/A	8	16
First Year Cost			
Capital Cost ($)	25,300,000	14,500,000	5,900,000
O&M Costs ($)	7,100,000	3,600,000	8,846,400
Total Cost ($)	32,400,000	18,100,000	14,750,000
Total Cost per kW ($/kW)	2,000	1,100	920
Life Cycle Cost			
Life Cycle Capital Cost ($)	25,400,000	14,500,000	5,960,400
Life Cycle O&M Cost ($)	141,900,000	164,000,000	203,140,000
Total LCC ($)	167,300,000	178,500,000	209,100,000
LCC per Unit Energy ($/kW)	10,420	11,100	13,000
Levelized Cost of Energy (cent/kWh)	13	13.85	16.22
GHG Emissions			
Annual GHG emissions[1] (tonCO_2)	37,710	26,870	24,900
Life Cycle GHG emission[1] (tonCO_2)	942,800	671,800	622,200
Annual GHG emissions[2] (tonCO_2)	37,710	48,190	87,200
Life Cycle GHG emission[2] (tonCO_2)	942,800	1,204,900	2,179,600

Notes:

1 PG&E emission factor

2 eGrid emission factor (U.S. average)

Table 5.3. Capital, O&M Costs, and GHG Emissions from Different Power Source Alternatives for Desalination Plants of 50 MGD Size

	LNG Power Generation	Hybrid System	Grid Electricity
LNG-Power Generation Capacity (MW)	32	16	N/A
Grid Capacity (MW)	N/A	16	32
First Year Cost			
Capital Cost ($)	61,800,000	33,800,000	5,900,000
O&M Costs ($)	12,500,000	7,100,000	8,846,400
Total Cost ($)	74,300,000	40,900,000	23,530,000
Total Cost per kW ($/kW)	2,300	1,300	730
Life Cycle Cost			
Life Cycle Capital Cost ($)	62,000,000	33,900,000	5,960,000
Life Cycle O&M Cost ($)	252,300,000	324,100,000	405,000,000
Total LCC($)	314,300,000	358,000,000	411,100,000
LCC per Unit Energy ($/kW)	9,790	11,200	12,800
Levelized Cost of Energy (cent/kWh)	12.2	13.9	16.0
GHG Emissions			
Annual GHG emissions[1] (tonCO_2)	67860	53730	49800
Life Cycle GHG emission[1] (tonCO_2)	1696500	1343200	1244500
Annual GHG emissions[2] (tonCO_2)	67860	96360	174400
Life Cycle GHG emission[2] (tonCO_2)	1696500	2409000	4359100

Notes:

1 PG&E emission factor

2 eGrid emission factor (U.S. average)

A series of sensitivity analyses were carried out with variations in several important parameters that could potentially have a significant influence on the final first year or life-cycle cost of various power supply options. The parameters that were varied for these sensitivity analyses and related ranges of variations are listed in Table 5.4. These calculations allow a more in-depth understanding of possible trends in the cost of energy generation as potentially significant factors changed, and to help understand which of the many input parameters are critical to the cost of energy generation.

The sensitivity analyses were carried out for three desalination plant size options, specifically 5 MGD, 25 MGD, and 50 MGD.

Table 5.4. Variability of Parameters for the Sensitivity Analysis

		Values Tested			
Parameter	Unit	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Electricity Rate (Purchase)	$/kWh	0.05	0.08	0.10	0.15
Fuel Purchase (for LNG)	$/MMBTU	5	8	10	12
Plant Efficiency (Simple Cycle)	%	35	40	45	-
Plant Efficiency (Simple Cycle)		45	50	55	-
Financing Interest Rate		4	5.25	7	-

5.3.1 Impact of Electricity Tariff Rates

This section presents sensitivities of the economic evaluations for the grid connection alternative to various electricity tariff rates. For this investigation the demand charge was not modified from the baseline value. This investigation was conducted because of the high differential tariff between different regions and time of the year. The baseline electric tariff rate used in this report was $0.08/kWh. Three additional rates were evaluated to assess the sensitivity of the results to higher and lower tariff rates for two desalination plant sizes.

Figure 5.13 shows the total LCC of a grid connection at two desalination plants of different sizes for different tariff rates. From the sensitivity analysis results, it is clear that, regardless of the desalination plant size, the total LCC of the project is affected by possible variations in the electric tariff rate applied. In particular, by increasing the rate from the 8 cents/kWh baseline, an increase in the total LCC is observed. Differences in slopes between the 25 and 50 MGD profiles are mostly due to the 3% increase in O&M cost escalation assumed for these case studies. As Figure 5.14 shows, a 24% increase in total LCC was obtained at a rate of 10 cents/kWh and rose to approximately 85% at 15 cents/kWh. In contrast, a 36% decrease in LCC was achieved when the tariff rate was set at 5 cents/kWh.

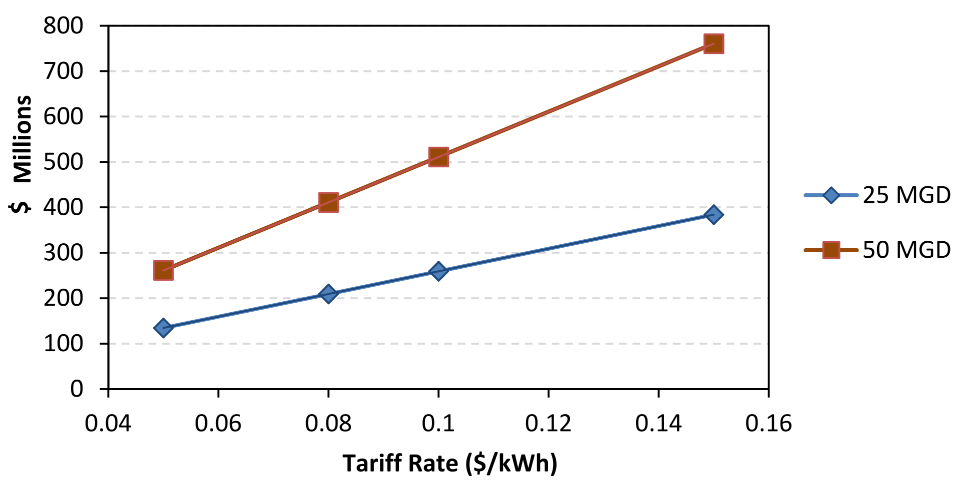


Figure 5.13. Total LCC for different electric tariff rates.

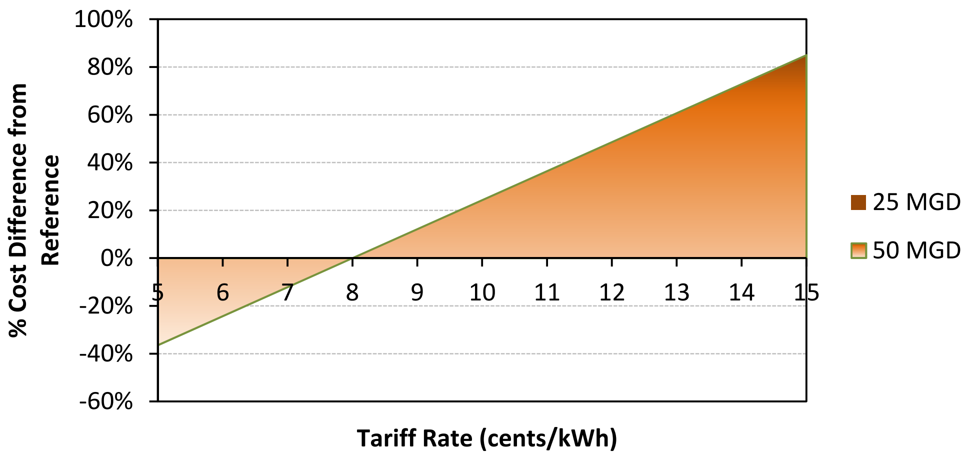


Figure 5.14. Total LCC difference of varying LNG prices from baseline value.

5.3.2 Impact of LNG Fuel Cost

This section presents sensitivities of the economic evaluations for the on-site power generation alternative to various LNG prices. This investigation was conducted because of the high volatility of LNG prices over the long term. In periods of domestic NG production cost increase, the imported LNG becomes a valuable option. The baseline price of LNG used in this report was $8/MMBTU. Three additional LNG prices were evaluated to assess the sensitivity of the results to higher and lower LNG prices for two desalination plant sizes.

Figure 5.15 shows the total LCC of an on-site power generation project using LNG at two desalination plants of different sizes. From the sensitivity analysis results, it is clear that, regardless of the desalination plant size, the total LCC of the project is affected by possible variations in the costs of the LNG. In particular, by increasing the fuel price from the baseline, an increase in the total LCC is observed. In particular, as Figure 5.16 shows, a 17% increase in total LCC was obtained at a LNG price of $10/MMBTU and reached up to approximately 35% at $12/MMBTU fuel cost. In contrast, about a 25% decrease in LCC was achieved when the LNG price was set at $5/MMBTU.

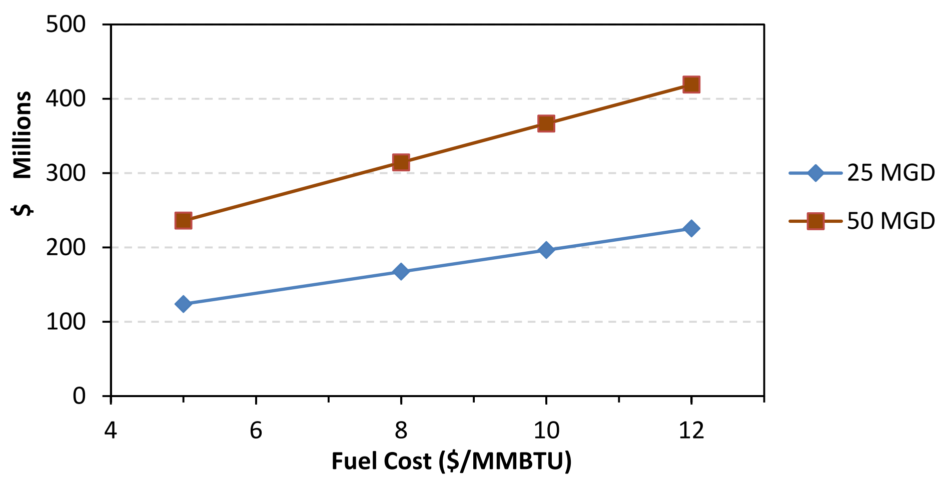


Figure 5.15. Total LCC for different LNG prices.

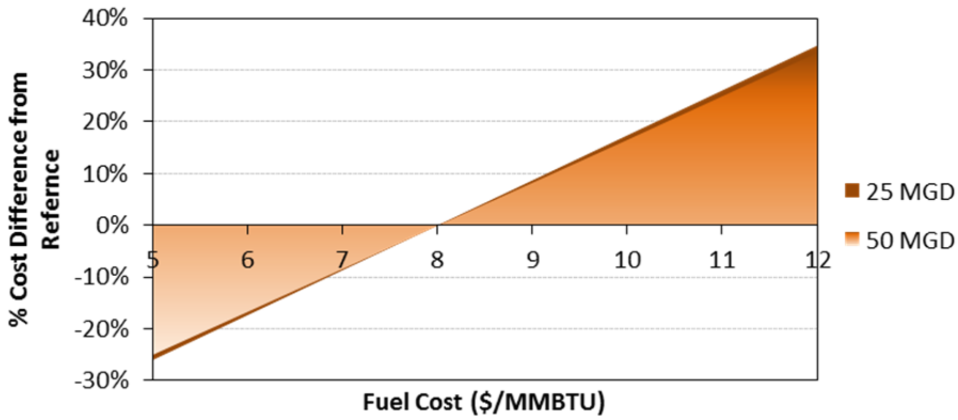


Figure 5.16. Total LCC difference of various LNG prices from baseline value.

5.3.3 Impact of Power Plant Efficiency

This section presents sensitivities of the economic evaluations for the on-site power generation alternative to various power plant efficiencies. The baseline efficiency for simple cycle power plants was set at 45%, whereas 50% was attributed to combined cycle configurations. Two additional plant efficiencies were evaluated to assess the sensitivity of the results from simple cycle plants to higher and lower efficiencies for two desalination plant sizes. For combined cycle, a higher range of efficiency was tested as this type of configuration is generally more efficient than the simple cycle.

Figure 5.17 shows the total LCC of an on-site power generation project of various efficiencies at two desalination plants of different sizes. From the sensitivity analysis results, it is clear that, regardless of the desalination plant size, the total LCC of the project is affected by possible variations in the plant efficiency. In particular, by increasing the efficiency from the baseline, a decrease in the total LCC is observed. In particular, as Figure 5.18 shows, a 20% increase in total LCC was obtained by decreasing simple cycle plants efficiency from the 45% baseline value to 35%. In contrast, about a 5% increase in LCC was achieved for combined cycle plants when the efficiency was increased from the baseline 50% to 55%.

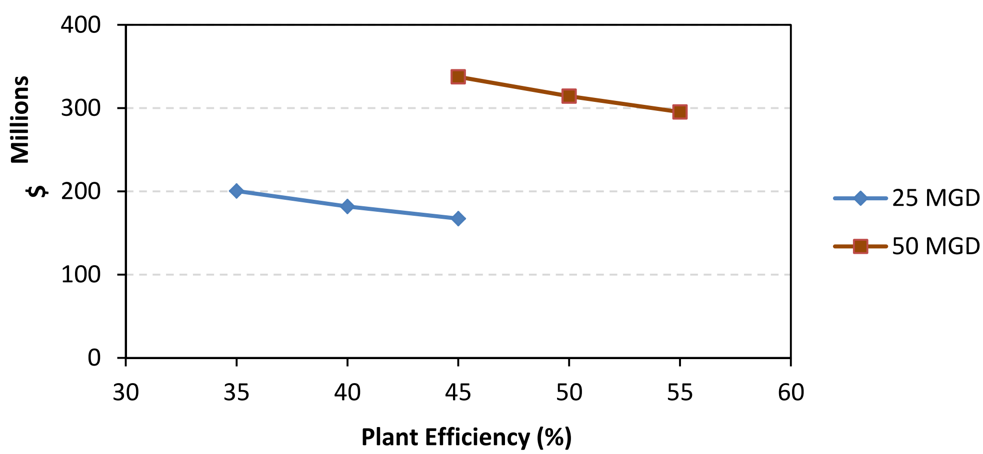


Figure 5.17. Total LCC at various power plant efficiencies.

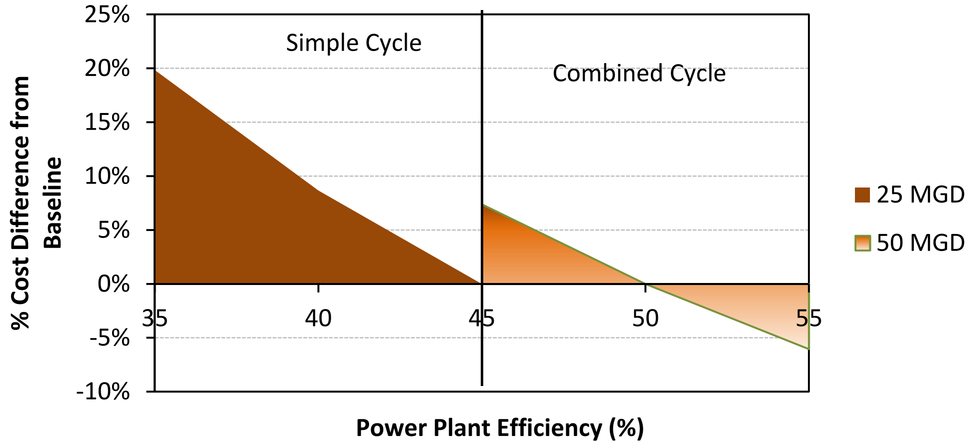


Figure 5.18. Total LCC difference of various power plant efficiencies from baseline value.

5.3.4 Impact of Financing Interest Rate and Discount Rate

This section presents sensitivities of the economic evaluations for the different power generation alternatives to various financing interest and discount rates. The baseline financing interest and discount rates for these options was set at 5.25%. Two additional financing interest and discount rates were evaluated to assess the sensitivity of the results for two desalination plant sizes, 25 and 50 MGD.

Figure 5.19 shows the total LCC of an on-site power generation, hybrid system, and grid electricity connection project at various financing interest and discount rates. From the sensitivity analysis results, it is clear that, regardless of the desalination plant size, the total LCC of the project is affected by possible variations in the financing interest and discount rates. An increase in the discount rate causes a decrease in the present value of the life cycle O&M and consequently decreases the total LCC because the O&M costs represent the majority (i.e., >80%) of the total LCC. In particular, by increasing the financing interest and discount rates from the baseline, a decrease in the total LCC is observed. In particular, as Figure 5.20 shows, up to a 15% decrease in total LCC was obtained by increasing financing interest and discount rates from the 5.25% baseline value to 7% for a 50 MGD desalination plant. In contrast, about the same percentage increase in LCC was achieved when the financing interest and discount rates was decreased from the baseline to a 4% value.

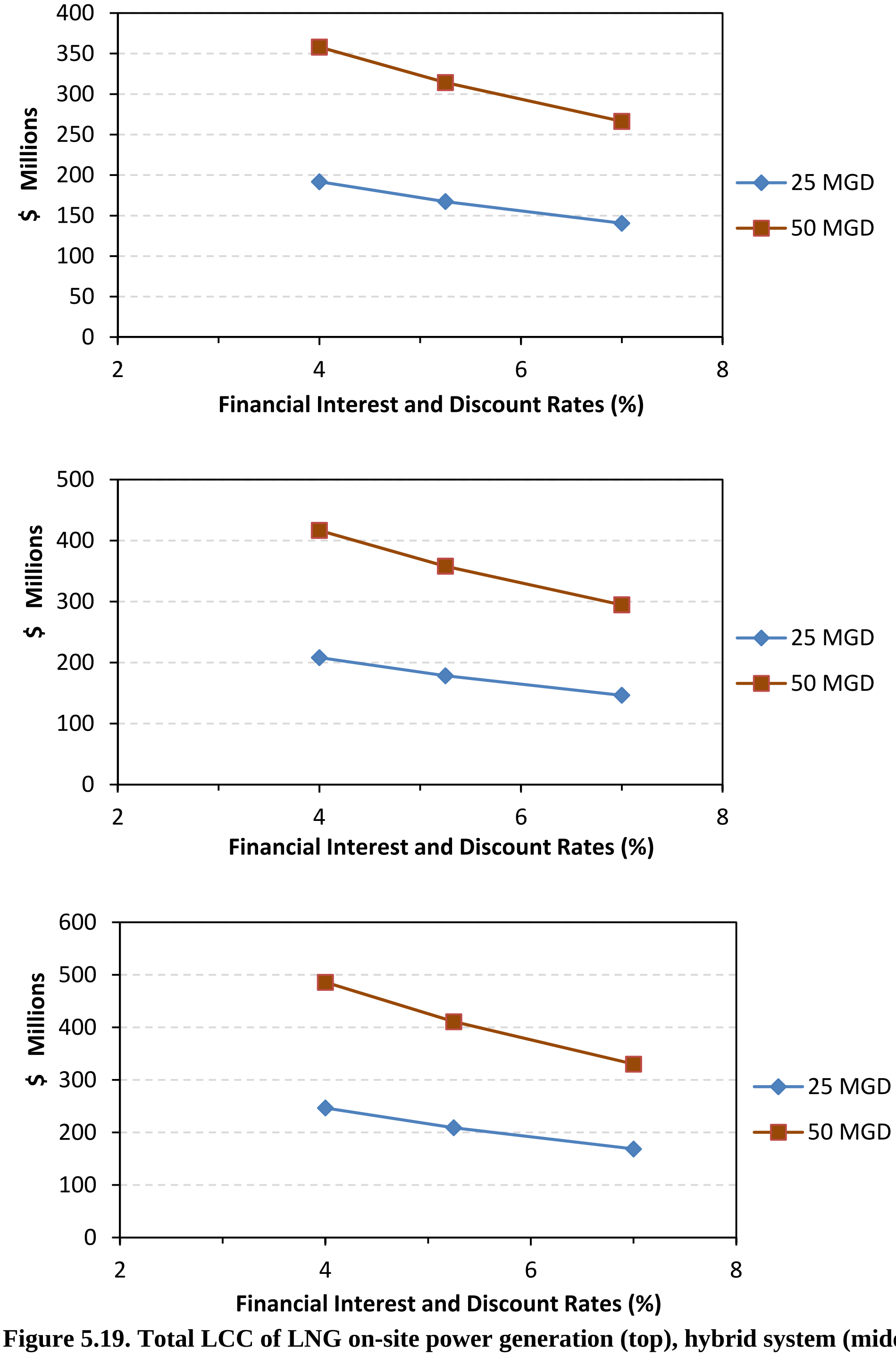


Figure 5.19. Total LCC of LNG on-site power generation (top), hybrid system (middle), and grid electricity (bottom) for various financial interest and discount rates.

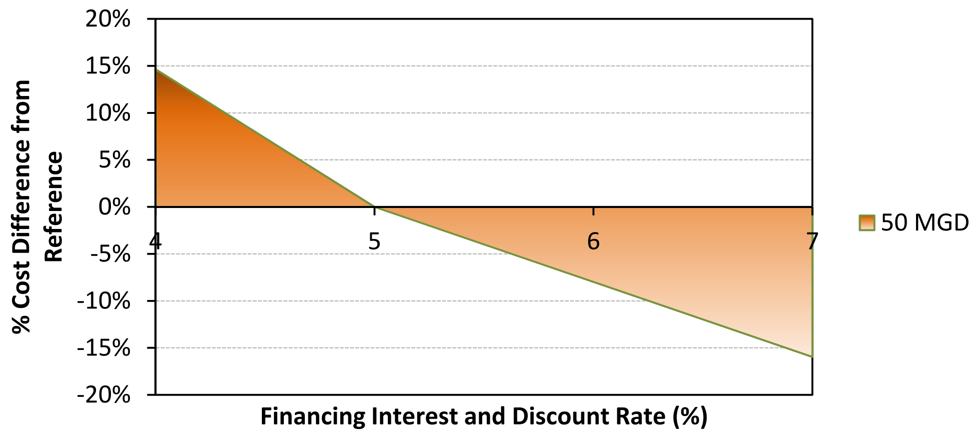


Figure 5.20. Example of total LCC difference of various financing interest and discount rates from baseline value for an LNG on-site power generation plant at a 50 MGD desalination plant.

5.4 Competitiveness of LNG Versus Grid

The results of the sensitivity analysis presented in Section 5.3 show the importance of the energy and fuel prices for the economic assessment of an LNG or a grid electricity option for powering desalination plants. Therefore, an economic comparison should be developed between LNG and grid electricity options to evaluate the most economically favorable options. The comparative analysis should be based on the ratio of LCOE developed for the "best" and "worst" scenarios for the LNG and the grid electricity alternatives, as expressed by the following formula:

$$C_E = \frac{LCOE_{Grid}}{LCOE_{LNG}} \tag{5-1}$$

Where $LCOE_{Grid}$ is the levelized cost of electricity with grid electricity and the $LCOE_{LNG}$ is the levelized cost of electricity with LNG. For the case studies developed in the previous section, three competitiveness indicators C_{E1}, C_{E2}, and C_{E3} were developed using the following equations:

$$C_{E1} = \frac{LCOE_{Grid}\,(Worst\ Scenario)}{LCOE_{LNG}\,(Best\ Scenario)} \tag{5-2}$$

$$C_{E2} = \frac{LCOE_{Grid}\,(Best\ Scenario)}{LCOE_{LNG}\,(Worst\ Scenario)} \tag{5-3}$$

$$C_{E3} = \frac{LCOE_{Grid}\,(Best\ Scenario)}{LCOE_{LNG}\,(Best\ Scenario)} \tag{5-4}$$

Four scenarios are possible based on the resulting values of the competitiveness indicators.

- If C1 < 1, the grid electricity will appear to be economically favorable.
- If C2 > 1, the LNG option will appear to be more favorable.
- If C1 > 1 or C2 < 1, either option may be favorable; other criteria should be considered beyond the economic evaluations.
- If C3 > 1, the LNG option is more favorable under the most favorable conditions.

To provide an example on how desalination utilities should determine which power supply option is the most economically appealing, this comparative analysis was developed for the two conceptual reference case studies of a mid-range capacity seawater desalination plants (25 and 50 MGD) developed in Section 5.3. Two “worst” case scenarios conditions were tested using:

- Example 1- Fuel cost: $5/MMBTU and tariff rate: $0.05/kWh (Table 5.5)
- Example 2 - Fuel cost: $8/MMBTU and tariff rate: $0.08/kWh (Table 5.6)

The LCOE values obtained for these case studies and example are reported in Tables 5.5 and 5.6.

Table 5.5. LCOE of “Best” and “Worst” Scenarios for LNG and Grid at Desalination Plant Sizes of 25 and 50 MGD Calculated for Example 1

	LCOE (cents/kWh)	
	25 MGD	**50 MGD**
LNG (Best Scenario, Fuel Cost: $5/MMBTU)	9.6	9.2
Grid (Best Scenario, Tariff Rate: $0.05/kWh)	10.4	10.1
LNG (Worst Scenario, Fuel Cost: $12/MMBTU)	17.5	16.3
Grid (Worst Scenario, Tariff Rate: $0.15/kWh)	29.8	29.5

Table 5.6. LCOE of “Best” and “Worst” Scenarios for LNG and Grid at Desalination Plant Sizes of 25 and 50 MGD Calculated for Example 2

	LCOE (cents/kWh)	
	25 MGD	**50 MGD**
LNG (Best Scenario, Fuel Cost: $8/MMBTU)	13.0	12.2
Grid (Best Scenario, Tariff Rate: $0.08/kWh)	16.2	16.0
LNG (Worst Scenario, Fuel Cost: $12/MMBTU)	17.5	16.3
Grid (Worst Scenario, Tariff Rate: $0.15/kWh)	29.8	29.5

On the basis of the LCOE values determined, the competitiveness indicators C_{E1}, $C_{E2,}$ and C_{E3} were calculated and the results reported in Table 5.7. From the results, it is clear that for both Example 1 and Example 2, $C_{E1} > 1$ or $C_{E2} < 1$ will require further assessment because the result may favor either the grid or LNG option. However, the values of the C_{E3} indicator obtained reveal that the LNG option is the most favorable option under the most favorable conditions.

Table 5.7. Competitiveness Indicators for LNG and Grid Options Comparison

	Example 1		**Example 2**	
	25 MGD	**50 MGD**	**25 MGD**	**50 MGD**
C_{E1}	3.1	3.2	2.3	2.4
C_{E2}	0.6	0.6	0.9	1.0
C_{E3}	1.1	1.1	1.2	1.3

5.5 Implementation Framework

This study showed that the NG or LNG option may have the potential to be more economically favorable than the direct power purchase from the grid for desalination plants under co-located configurations with the power generation plant. Overall, the decision to develop gas-fueled power facilities versus connecting to the grid should take into consideration a number of issues that generally fall in the following categories:

- Customer requirements (e.g., electricity demand, process energy demand, operating philosophy, financing)
- Site-related factors (fuel, water, space availability, legislation/emission requirements)
- Design and operating parameters of the plant (type and number of gas turbines, single shaft versus multi-shaft, efficiency)

In this section a step-by-step framework was developed to guide desalination utilities toward a cost effective and sustainable selection of power supply. The framework that is presented in Figures 5.21 includes 10 fundamental steps; a brief description of each is provided in the following sections.

Step 1: Estimate Energy Requirements

Decision makers must first understand the total annual energy requirements (base and peak power) of the desalination facility, the make-up of that power mix (e.g., what fraction of total energy requirement will be met by LNG/NG), and the current cost of that power. If the desalination plant is solely powered by the LNG/NG power generation facility, a comprehensive reliability assessment of power generation should be conducted and a redundancy plan should be also developed.

Step 2: Assess LNG Availability

The spot market of LNG has emerged in recent years because of global overcapacity in liquefaction, an increase in the number of LNG tankers, and increased contractual flexibility across the various components of the LNG value chain. Under this arrangement, LNG can be purchased when and where it makes the most economic sense. The pros and cons of different contract terms such as long-term contracts, a spot market, or short-term contracts on LNG price should be carefully evaluated. The risks related to LNG price can be minimized by long-term supply contracts (20–25 years in duration), with a “take or pay” clause that obligates the seller to provide gas at a certain price regardless of market demand.

Step 3: Financing and Ownership Options

The structure of financing can impact project costs, control, and flexibility, as well as affect the long-term return on investment. The ownership of the project may also impact the economic feasibility of the project. From the owner’s perspective, the following three general ways can be used to structure the development of a power plant project:

- Develop the project internally. In this approach, the desalination facility owner hires a consultant, plans and manages the design–construction effort, and maintains ownership control of the project.
- Purchase a “turnkey” project. The desalination owner selects a qualified project development company to design, develop, and build the project on a “turnkey” basis, turning over ownership and operation of the facility to the owner after commissioning.
- Team with a partner. In this approach, the desalination plant owner teams with an equipment vendor, engineering/procurement /construction (EPC) firm, or investor to develop the project and to share the risks and financial returns under various partnership agreements.

LNG/NG power plants are often designed, built, and operated by gas turbine suppliers. Therefore, it is important to work closely with these vendors. The pros and cons associated with financing and ownership options should be evaluated.

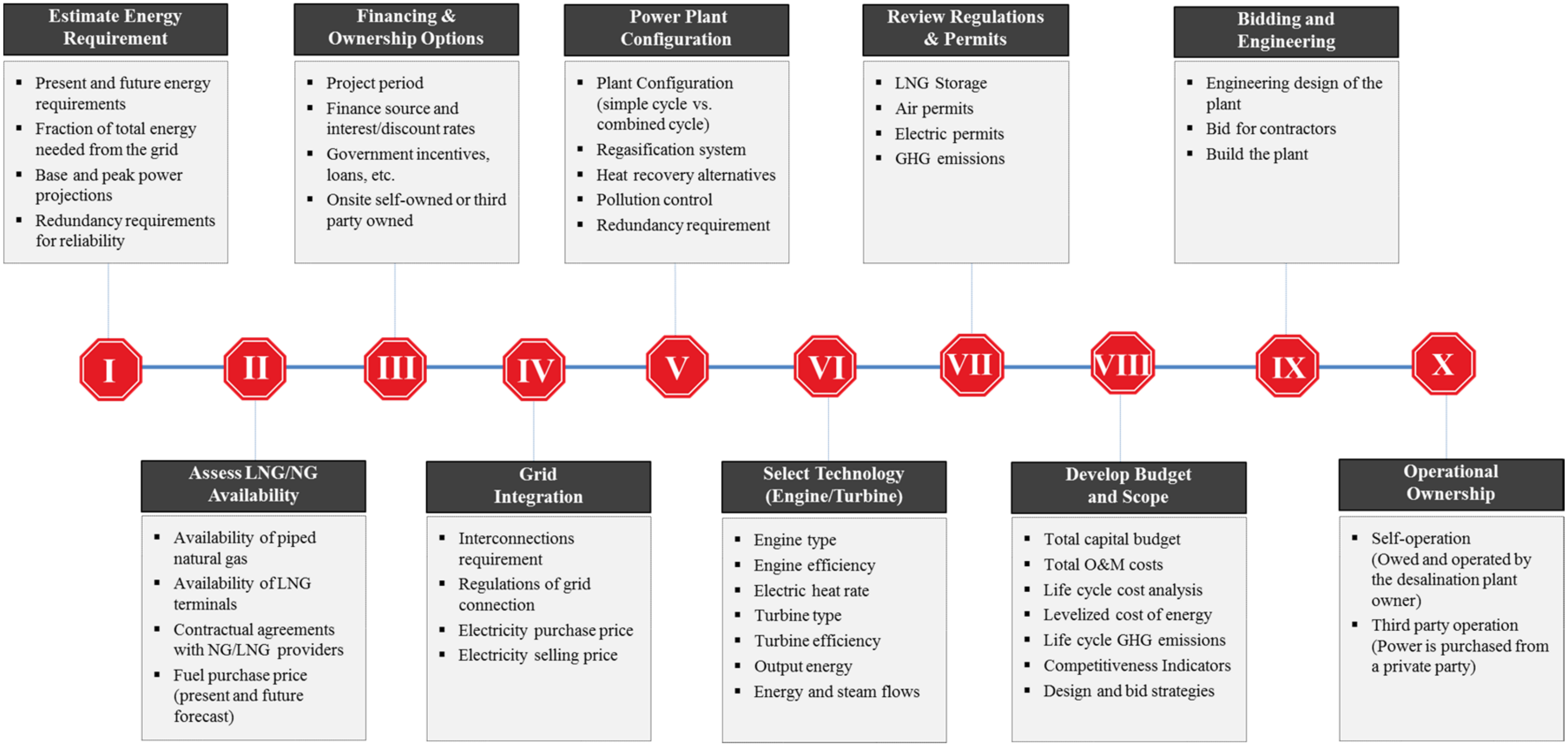


Figure 5.21. Conceptual implementation framework.

Step 4: Grid Integration

The integration of the LNG/NG power generation facility with the grid should occur to enable purchasing electricity during a downtime of the LNG/NG power generation facility and to sell excess electricity generated from the LNG/NG power generation facility. Integrated with the grid, an on-site power generation facility can be operated for the following three scenarios:

- The on-site power generation facility is independent of the electricity grid and has the capacity to produce all power required for the desalination facility;
- The on-site generation is based on the historic minimum demand (base-load operation), and supplemental power is purchased from the electric grid; or
- As a dual-purpose plant designed for the production of both water and electricity, and the excess power can be sold for revenue regeneration as a separate commodity.

The NG or LNG power plant built for seawater desalination might qualify to be part of the facilities under the Public Utility Regulatory Policies Act (PURPA) issued in 1978. The PURPA promotes a new class of power generation facility that may receive special rate and regulatory treatment. The qualifying facilities (QFs) under this Act can be categorized into the following types:

- *Small power production facilities*. A generating facility of 80 MW or less whose primary energy resource is renewable (hydro, wind, or solar), biomass, waste, or geothermal.
- *Cogeneration facilities*. A power generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy.

There is no size limitation for qualifying cogeneration. According to the regulation, the electrical, thermal, and chemical output of a new cogeneration facility must be used fundamentally for industrial, commercial, residential, or institutional purposes and is not intended primarily for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

If approved as a PURPA QF, a NG or a LNG powered desalination plant may have access to the following benefits:

- Right to sell QF energy or capacity to a utility. QFs have the right to sell energy and excess capacity to a utility either at its avoided cost or at a negotiated rate, provided the purchasing utility has not been relieved from its QF purchase obligation. Avoided cost is the incremental cost to an electric utility of electric energy or capacity which, except for the purchase from the QFs, such utility would generate itself or purchase from another source.
- Right to purchase certain services from utilities. QFs have the right to purchase supplementary, back-up, maintenance, and interruptible power at rates that are just and reasonable, based on accurate data and consistent systemwide costing principles, and that apply to the utility's other customers with similar load or cost-related characteristics.
- Relief from regulatory burdens. If qualified the power plant of the desalination facility may have reliefs from some regulatory challenges, such as:
    - QFs are exempt from state laws and regulations respecting the rates and financial

and organizational aspects of utilities;

- QFs are exempt from the Public Utility Holding Company Act of 2005 (PUHCA);
- QFs are largely exempt from most sections (not including sections 205, 206 and certain other sections) of the Federal Power Act (FPA); and
- If 20 MW or smaller, energy and capacity sales made by the QFs may be exempt from scrutiny under sections 205 and 206 of the FPA.

For additional information on the PURPA regulations, it is recommended to review the resources available on the Federal Energy Regulatory Commission website (FERC, 2015).

The interconnection equipment and ancillary regulations should be properly evaluated. The interconnection agreement should cover issues such as back-up services, metering requirements, inspection rights, insurance requirements, and the responsibilities of each individual party.

Step 5: Select Power Plant Configuration

Cogeneration and combined cycle applications are common for generating power on-site. A clear understanding of their efficiencies and costs, and the factors impacting these parameters are needed to make an economical selection. The efficiency of electric power generation for combustion turbine systems, operating in a simple-cycle mode, ranges from 21 to 40%. About 60% efficiency is possible when the turbine exhaust heat is recovered in a heat recovery steam generator to produce steam that can either be used for mechanical/process needs or for generation of additional power in a steam turbine. The design and operational characteristic of the power plants are discussed in Chapter 3. However, it is recommended to work with experienced power generation facility engineers to develop the design specifications for the plant.

Step 6: Select Technology

Over time, engine and turbine technologies are becoming more and more efficient. A large number of vendors are available with a wide array of engines or turbines. Thus, recent developments in the gas turbine technology and their existing installations should be carefully examined. Key design and operational characteristics with the engines or turbines are discussed in Chapter 3.

Step 7: Review Regulations and Permits

A large-scale seawater desalination plant project will require numerous permits and approvals from a variety of local, state, and federal agencies before construction can commence and before the plant can be placed into operation. Obtaining these permits and approvals is critical to moving a project forward. This section only discusses the critical regulations that may impact the application of LNG/NG at desalination facilities. The regulations associated with water production from the desalination facility are not discussed here. The regulations related to three major categories such as (1) power generation, (2) GHG emissions, and (3) air quality are presented in the following.

GHG Emission Rules. On April 13, 2012, under the authority of the Clean Air Act (CAA) Section 111, the EPA proposed a new source performance standard (NSPS) to limit emissions of carbon dioxide (CO_2) from electric generating units (EGUs), including NG-fired units. This action proposes standards of performance for NG-fired stationary combustion turbines based on modern, efficient NG combined cycle technology as the best system of emission reduction (BSER). The proposed emission limit is 1000 lbs-CO_2/MWh for larger units and 1100 lbs-CO_2/MWh for smaller units. The EPA has recently announced that it will soon finalize the proposed Carbon Pollution Standards for new power plants. Additional information on this regulation is available on the EPA website (EPA, 2015).

Each LNG/NG-powered desalination facility should follow national and regional regulation on the reporting requirements for GHG emissions. In some cases, the reporting can be mandatory. For example, in California, electricity generating units (including cogeneration) are subject to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Title 17, California Code of Regulations). According to the regulation, any standalone power plant and cogeneration facility (industrial, commercial, or institutional) with greater than or equal to 10,000 metric tons carbon dioxide equivalent (MT-CO_2eq) of emissions should comply with the mandatory reporting protocol.

***Criteria Pollutants from NG-Fired Engines*.** The operation of a NG-powered engine is regulated by local air districts that are charged with assuring their district's attainment of federal and state clean air standards. The primary criteria pollutants, as defined by the Federal Clean Air Act, released from NG-fired reciprocating engines are:

- nitrogen oxides (NOx),
- carbon monoxide (CO), and
- volatile organic compounds (VOC).

The formation of nitrogen oxides is exponentially related to combustion temperature in the engine cylinder. The other pollutants, CO and VOC species, are primarily the result of incomplete combustion.

Particulate matter (PM) emissions are trace amounts of metals, noncombustible inorganic material, and condensible, semi-volatile organics that result from volatized lubricating oil, engine wear, or from products of incomplete combustion. Although sulfur oxides are very low because sulfur compounds are removed from NG at processing plants, trace amounts of sulfur-containing odorant are added to NG at city gates prior to distribution for the purpose of leak detection.

The air districts are "in attainment" of the federal and state clean air standards for selected air pollutants and are in "non-attainment" with other pollutants. Therefore, the air permitting requirements to construct and operate a stationary NG engine depends on each district's status. Therefore, any agency proposing to construct, modify, or operate a facility that may emit these pollutants must obtain an authority to construct from the county or regional air pollution control districts or air quality management district.

Typically special purpose equipment is installed to meet with air quality district rules. The equipment is available in two types: Best Available Technology Control (BACT) and "Reasonably Available Control Technology" (RACT).The emission thresholds for BACT are more stringent than RACT and are typically applied to new engines and/or for older engines that fail to comply with maximum allowable thresholds for one or more regulated pollutants. In California, each air district has the right to determine its own BACT. The air quality regulation and permitting procedures may vary from one state to another. California has significant environmental permitting requirements, largely managed at the regional and county levels (e.g. South Coast Air Quality Management District and Santa Barbara Air Pollution Control District). The State of California air quality rules can often be more stringent than federal standards. The Texas Commission on Environmental Quality (TCEQ) and Florida Department of Environmental Protection (FDEP) have been delegated authority to enforce air quality regulation at the state level with counties having less significant jurisdiction. For example, in Florida, electric power generation facilities are handled by the Division of Air Resources Management in Tallahassee, with regional offices handling smaller facility permitting duties. A list of agencies that are responsible for air monitoring, permitting, enforcement, long-range air quality planning, regulatory development, and education and public information activities concerning air pollution are presented in Table 5.8.

Table 5.8. Statewise List of Regulatory Agencies and their Website Locations for Regulatory Information

State	Regulatory Agency	Reference
California	Air Quality Management District	http://www.aqmd.gov/home/regulations/rules/scaqmd-rule-book/regulation-xi
Texas	Texas Commission of Environmental Quality	http://www.tceq.texas.gov/rules/indxpdf.html
Florida	Florida Department of Environmental Protection	http://www.dep.state.fl.us/Air/rules/current.htm

Step 8: Develop Budget and Scope

The project delivery method and procurement approach will substantially influence project results, particularly regarding how risk ownership is handled. It is important to recognize that an owner's choice of delivery methods determines how the project will be procured, executed, and how key stakeholders will communicate with each other. Typical delivery methods are: (a) design bid build (DBB), (b) fixed price design build (DB), (c) progressive design build (PDB), and (d) design build operate (DBO). The advantages and disadvantages of each delivery method with respect to various issues such as construction, equipment performance, financial performance, and so on should be evaluated prior to releasing the request for proposal.

Step 9: Bidding and Engineering Design

The technical bid evaluation comprises technical (including safety), economic, financial, contractual, political, organizational, and other applicable aspects that have to be considered in the decision-making process for implementing the project and the selection of the supplier(s). Thus, it is recommended to assemble a highly experienced team to evaluate the bids and engineering designs.

Step 10: Operational Ownership

The benefits and challenges associated with different operational ownership options, as discussed in Step III, should be carefully examined.

Chapter 6

Conclusions and Recommendations

This chapter summarizes the major findings of the study and identifies the remaining knowledge gaps for moving towards wider scale applications of LNG for power generation at desalination facilities.

6.1 Conclusions

6.1.1. Key Finding 1: Co-location of a LNG/NG-based power generation facility and a seawater desalination plant is increasingly being considered as an alternative to using the grid electricity option.

Traditionally, desalination plants have relied on the power grid as the preferred power supply option. In recent years, the application of NG and LNG has been considered as an alternative to meet the high energy demand of desalination processes. Several desalination plants worldwide use LNG or NG as a main source of power supply and are mostly located in regions, such as the Middle East, where the cost of NG is inexpensive.

Most of the NG-powered seawater desalination plants are co-located with large power generation plants (>500MW) and are based on thermal desalination processes. However, a number of reverse osmosis plants are also being powered by natural gas.

Recent developments of more efficient gas engines and/or turbines allow the following two primary methods for the application of LNG/NG in a desalination facility: (a) as a fuel for an on-site power generation facility that can supply electricity for desalination with potential opportunity to augment the grid electricity capacity of the community, and (b) as a fuel for gas engines that are currently large enough (up to 10 MW size) to run the high-pressure pumps of large desalination facilities.

6.1.2. Key Finding 2: A wide variety of gas engines and turbines are commercially available for generating electricity on-site or for running high-pressure pumps of the desalination process; therefore, the design and operational specifications of engines or turbines need to be clearly evaluated to assess the economic feasibility of the use of NG or LNG at desalination plants.

On-site power generation plants evaluated for 5 to 100 MW capacity suggests that the plants can be designed to operate in simple cycle or combined cycle modes, and the configuration influences the plant’s operational efficiency, overall performance, and total costs. The efficiency of electric power generation for combustion turbine systems (40% efficient), operating in a simple-cycle mode is typically lower if compared with those in the combined cycle (50% efficient) producing high-quality heat, steam, and hot water for other applications. This study suggests that power plant sizes larger than 20 MW should be considered as a combined cycle operation.

In hybrid systems LNG or NG is used as a fuel to drive high-pressure pump motors with the remaining of the energy provided by the electricity grid. Gas engines of sizes between 0.5 and 10 MW can be considered for this purpose, however, an overall increase in efficiency and decrease in capital expenditures are observed for larger size engines.

For a grid-connected seawater desalination plant, the interconnection of a desalination plant to an electric utility power grid can also be capital intensive, particularly for electrical loads of 10 MW and higher, because of the need for a substation and transmission equipment.

6.1.3. Key Finding 3: LCC analysis should be conducted to understand and compare the economic benefits of an LNG/NG-based power supply with the grid electricity supply.

On the basis of the conceptual cost analysis on 2.5 MGD to 150 MGD desalination plants, the grid electricity requires lower capital investments than the LNG-based options for sizes above 10 MGD. Conversely, from an annual O&M cost perspective, the LNG-based option appears to be a more economical solution for desalination plant of capacity above 10 MGD.

The size of a desalination plant might be an important factor in the economic assessment of the applicability of grid- versus LNG-base power supply. Based on a life cycle analysis conducted in this study, the LNG on-site generation alternative generates 30% lower total LCC than the grid connection for desalination plants that are larger than 20 MGD. For smaller desalination capacities (i.e., <20 MGD) the LCC for the grid option and that of on-site generation are comparable and could be within 5 to 13% difference.

The LCOE analysis performed to compare the cost of energy generated by the different power source options showed that for desalination capacities of 10 MGD and higher, the on-site power generation using LNG is the lowest-cost option with LCOE values of 13 cents/kWh and lower.

The cost of fuel contributes significantly in the economic feasibility of LNG versus NG. In addition to the fuel price, LNG-based power generation systems need the regasification system to revaporize the LNG into gas for use and incur higher O&M costs because of the higher LNG market price. Thus, the total LCC of the LNG-based on-site power generation system is 43% to up to 86% higher than the NG-based counterpart for desalination plants with increasing size from 2.5 MGD to 150 MGD, respectively. For LNG-based hybrid systems, the total LCC is 20 to 26% higher than the NG-based counterpart for the same desalination plant sizes.

6.1.4. Key Finding 4: Sensitivity and competitiveness analyses need to be conducted to determine the best power supply option using the tool developed in this study.

The economic comparison outcomes between the grid electricity and LNG-based power supplies are dictated by a number of key factors such as electricity rate, LNG/NG price, financing interest rate, and gas or turbine engine efficiency. From a sensitivity analysis conducted on these parameters at two conceptual 25 and 50 MGD seawater desalination plants, the following trends were observed:

- The total LCC of the project is affected by possible variations in the electric tariff rate that is applied. In particular, by increasing the rate from 8 to 15 cents/kWh, an 85% increase in the total LCC was observed for the grid electricity power supply option.
- The total LCC of the project is affected by possible variations in the costs of the LNG. In particular for on on-site power generation alternative, a 35% increase was observed by increasing the cost of fuel from $8/MMBTU to $12/MMBTU.
- The total LCC of a project is affected by possible variations in the plant efficiency. In particular, a 20% increase in total LCC was obtained by decreasing a simple cycle plant's efficiency from the 45% baseline value to 35%. Conversely, about 5% increase in LCC was achieved for combined cycle plants when the efficiency was

increased from the baseline 50% to 55%.

- The sensitivity of LCC to the financing interest/ discount rates was shown by increasing the financing interest and discount rates from the baseline, a decrease in the total LCC was observed. An increase in the discount rate causes, in fact, a decrease in the present value of the life cycle O&M and consequently decreases the total LCC because the O&M costs represent the majority (i.e., >80%) of the total LCC. For instance, for a 50 MGD desalination plant, a 15% decrease in LCC was achieved when the financing interest/discount rate was increased from 5.25% to a 7% value.

This study introduced a cost competiveness assessment of different scenarios (e.g., best scenario for LNG versus worst scenario for the grid-based power supply, worst scenario for LNG versus best scenario for the grid-based power supply, etc.) for comparative assessment when a great deal of uncertainties exist in setting the appropriate values for the various factors. If either the on-site LNG generation option or the grid option could be favorable based on the competitiveness analysis, other criteria should be considered beyond the economic evaluation to make a selection.

6.1.5. Key Finding 5: The life cycle GHG emissions should be evaluated to determine the potential to generate GHG emissions over the power generation project life time.

GHG emissions arise from electricity usage and from the possible use of alternative fuels. The GHG emission from the grid power supply is sensitive to the energy mix used in the grid and the associated emission factor. On the other hand, the efficiency of the engine/turbine impacts the GHG emission from an on-site power generation facility. The life cycle analysis for the assessment of the GHG emissions showed that when low GHG emission factors are used, such as in some areas in California under the PG&E service area, the grid electricity option resulted in lower life-cycle GHG emissions than those of the LNG/NG power source alternatives. For higher emission factors, such those typically established as a U.S. national average by the U.S. EPA, the opposite was observed and the LNG-based on-site power generation appears to be the most sustainable option.

6.2 Recommendations

6.2.1. Recommendation 1: Convene an expert workshop panel with regulators, LNG/NG providers, and desalination experts.

Bringing desalination experts with power plant designer and equipment suppliers together may allow for a discussion that can improve the co-existence of these entities and overcome the barriers and challenges that both sectors have been facing. Also, an experts roundtable should discuss the future potential for LNG/NG applications for desalination in the United States and globally and foster the potential development of joint programs between the two sectors that could result in adoption of energy efficiency and more sustainable strategies, increased savings of both energy and water resources, and shared financial opportunities between the two industries.

6.2.2. Recommendation 2: Perform surveys to collect relevant information on the operation of LNG/NG-based power plants co-located with desalination plants.

The analysis of the case studies highlighted a number of knowledge gaps, some of which are associated with the paucity of data in the public domain and the domain of private entities. Information on the design specifications, operations, and cost of LNG/NG power generation plants that feed desalination processes remain mostly undisclosed. Therefore, in order to further advance our knowledge on the use of LNG/NG to power desalination facilities, the collection of these relevant data and results of NG/LNG power plants auditing is important.

6.2.3. Recommendation 3: Identify barriers and challenges of integrating LNG plants with the grid.

To best manage the challenges of integrating LNG/NG plants into electricity grids, policy, planning, and regulatory interventions should be designed to minimize overall system costs and meet performance targets. In order to develop a comprehensive approach and system planning that allows LNG/NG plant integration with the power grid and minimizes integration costs, it is important that the full range of barriers and challenges of the interconnection process and synchronization with power grid options are identified and fully understood.

6.2.4. Recommendation 4: Develop a decision matrix for selection of LNG over NG to power desalination facilities.

The application of LNG to power desalination has emerged in recent years, particularly in locations where the pipeline infrastructure option for NG is limited or nonexistent. A number of criteria should be evaluated when opting for LNG over NG or other fuel sources: availability of LNG and proximity to the desalination plant; capital investments and operational expenses; reliability of the fuel selected; technology selection; design specifications; project schedules; contractual terms; overall risks; permitting, siting, approval process; regulatory requirements and limitations; environmental compliance, and sustainability. A decision matrix should be developed to address these issues.

6.2.5. Recommendation 6: Developing a toolbox for permitting requirements.

The toolbox will guide desalination utilities on how to achieve regulatory flexibility and overcome the constraints of the power grid for integration into the power utility infrastructure. The toolbox should be also based on surveys of energy and air regulatory agencies to identify opportunities to resolve conflicts and create regulatory flexibility for desalination utilities. This framework also should be intended for use by utilities in regions that lack regulatory clarity.

References

API (American Petroleum Institute). *Consistent methodology for estimating greenhouse gas emissions from Liquefied Natural Gas (LNG) operations*. The Levon Group: Thousand Oaks, CA, July 2013.

Bachrach, D. R. Comparing the risk profiles of renewable and natural gas electricity contracts: A summary of the California Department of Water Resources Contracts. Master's Thesis, University of California, Berkeley, May 2002.

Callahan, N. Integration of Power Generation and Water Desalination Operations, 2015. http://texaswater.tamu.edu/readings/desal/powerneedsindesal.pdf (accessed February 2015).

CARB, California Air Resource Board (2012). http://www.arb.ca.gov/homepage.htm (accessed October 2014).

CEC (California Energy Commission). *Thermal Efficiency of Gas Fired Generation in California*; Report No. CEC-200-2011-008; California Energy Commission: Sacramento, CA, 2012.

CEE (Center for Energy Economics). *Introduction to LNG. An overview on liquefied natural gas (LNG), its properties, the LNG industry, and safety considerations*. Bureau of Economic Geology, Jackson School of Geoscience and The University of Texas at Austin, 2012.

Cooley, H.; Wilkinson, R. *Implications of Future Water Supply Sources for Energy Demands*; Report No. WRRF-08-16. WateReuse Research Foundation: Alexandria, VA, 2012.

Cooley H.; Heberger, M. *Key Issues for Seawater Desalination in California Energy and Greenhouse Gas Emissions*, May 2013. Pacific Institute: Beltsville, MD. www.pacinst.org/reports/desalination_2013/energy (accessed December 2014).

Elimelech, M.; Phillip, W. A. The future of seawater desalination: Energy, technology, and the environment. *Science* **2011**, *333*, 712–717.

FERC (Federal Energy Regulatory Commission). *General Information on Qualifying Facilities*. http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp (accessed March 2015).

Garb, Y. *Desalination in Israel: Status, Prospects, and Contexts*. Presented at the Water Wisdom Conference, Amman, Jordan, April 2008.

Ghaffour, N.; Missimer, T. M.; Amy, G. L. Technical review and evaluation of the economics of water desalination: Current and future challenges for better water supply sustainability. *Desalination* **2013**, *309*, 197–207.

Ghaffour, N.; Bundschuh, J.; Mahmoudi, H.; Goosen, M. F. Renewable energy-driven desalination technologies: A comprehensive review on challenges and potential applications of integrated systems. *Desalination* **2015**, *356*, 94–114.

Ghiu, S. *DORIS—Energy Consumption Calculator for Seawater Reverse Osmosis Systems*. Water Research Foundation: Denver, CO, 2014.

Greenlee, L. F.; Lawler, D. F.; Freeman, B. D.; Marrot, B.; Moulin, P. Reverse osmosis desalination: Water sources, technology, and today's challenges. *Water Research* **2009**, *43* (9), 2317–2348.

GWI (Global Water Intelligence). Desalination Markets, 2010. http://www.globalwaterintel.com/market-intelligence-reports/desalination-markets-2016/ (accessed March 2015).

Hurn, C.; Hagedorn, T. *Tuaspring Sea Water Desalination with CCPP in Singapore: An Example for Sustainable Power Generation*. PowerGen Asia, Bangkok, Thailand, October 3–5, 2012.

Jacangelo, J.; Subramani, A.; Oppenheimer, J.; Badruzzaman, M. *Renewable energy technologies and energy efficiency strategies (Guidebook for desalination and water reuse).* Report No. WRRF-08-13. WateReuse Research Foundation: Alexandria, VA, 2013.

Loeb, S.; Sourirajan, S. Seawater demineralization by means of an osmotic membrane. *Adv. Chem. Ser.* **1963**, *38*, 117–132.

Loveland, J. Personal email communication. February 2015.

Pinzon, J. *Energy efficiency in water reuse and desalination: Five individual projects which address energy efficiency in both water reuse and desalination*. Watereuse Research Foundation: Alexandria, VA, 2013.

Quteishat, K. *Energy for desalination*. Presented at Stockholm Water Week, Stockholm, Sweden, August 18, 2009.

Raluy, R. G.; Serra, L.; Uche, J. Life cycle assessment of desalination technologies integrated with renewable energies. *Desalination* **2005**, *183* (1), 81–93.

Rosso, D.; Rajagopalan, G. *Energy reduction in membrane filtration process through optimization of nanosuspended particle removal*. Report No. CEC-500-2013-132. California Energy Commission: Sacramento, CA, 2013.

Semiat, R. Energy issues in desalination processes. *Environmental Science and Technology* **2008**, *42*, 8193–8201.

Sempra Energy. Personal Communication (Email), May 29, 2014.

Subramani, A.; Badruzzaman, M.; Oppenheimer, J.; Jacangelo, J. G. Energy minimization strategies and renewable energy utilization for desalination: A review. *Water Research* **2011,** *45*, 1907–1920.

Tenne, A. *Sea Water Desalination in Israel: Planning, coping with difficulties, and economic aspects of long-term risks*. Water Authority, State of Israel, Desalination Division, October, 2010.

Voutchkov, N. *Seawater Reverse Osmosis Design and Optimization*. Presented at the Advanced Membrane Technologies, Stanford University, Stanford, CA, May 07, 2008.

Voutchkov, N. *Power Plant Co-Location Reduces Desalination Costs, Environmental Impacts*. http://www.waterworld.com/articles/iww/print/volume-7/issue-1/columns/product-focus/power-plant-co-location-reduces-desalination-costs-environmental-impacts.html (accessed August 2014).

U.S. EPA (Environmental Protection Agency). *eGrid*, **(**Emissions & Generation Resource Integrated Database), 9th edition Version 1.0, 2010 Summary Tables. February 2014.

U. S. EPA. Proposed Carbon Pollution Standard for New Power Plants, 2013. http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants (accessed December 2014).

WRRF (WateReuse Research Foundation). *Seawater desalination costs*. A white paper. WateReuse Research Foundation: Alexandria, VA, 2012.

WateReuse Association. *Seawater Desalination Power Consumption*. A white paper. WateReuse Association: Alexandria, VA, November 2011.

World Bank. Renewable Energy Desalination: An Emerging Solution to Close the Water Gap in the Middle East and North Africa. *Mena Development Report*. World Bank: Washington, DC, 2012.




WateReuse

1199 North Fairfax Street, Suite 410
Alexandria, VA 22314 USA
703.548.0880
703,548.5085 (fax)
foundation@watereuse.org
www.WateReuse.org