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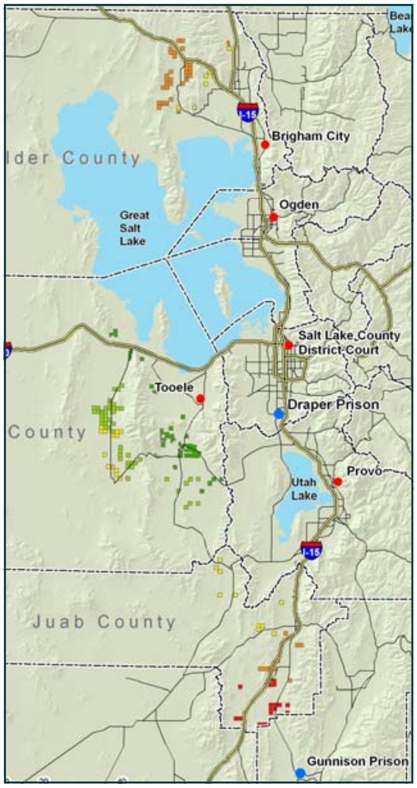
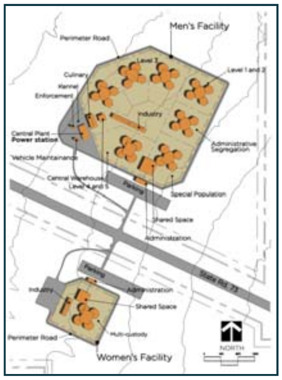
Third Prison Site Location Study

Utah Department of Corrections
Utah Division of Facilities Construction and Management

July 2009





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THIRD PRISON SITE LOCATION STUDY

Utah Department of Corrections
Utah Division of Facilities Construction and Management

Project Team:
Wikstrom Economic and Planning Consultants, Inc.
GSBS Architects
Parametrix
Stantec Consulting, Inc.
Spectrum Engineers, Inc.
Weber Sustainability Consultants

January 2009

INTRODUCTION

The Utah Department of Corrections ("DOC") has undertaken this study in order to plan for the growth of its prisoner population, which will need a significant amount of new space in the next few years. Currently there are approximately 6,700 inmates in the State's prison system. According to the Department of Corrections roughly 190 prisoners enter the system every year. This means in about seven years another prison the size of the Central Utah Correctional Facility, which can accommodate 1,340 prisoners, will be needed. Given that it takes approximately 4 years to design and build a prison, now is a good time to secure a site in advance of the planning process.

Some of the groundwork for this study was laid in 2006 when the State of Utah published a study entitled "Evaluation of the Feasibility of Relocating the Utah State Prison." This study was a response to popular interest in the removal and relocation of the State Prison in Draper to another site in a more rural area. The relocation study identified eastern Box Elder County, northeastern Juab County, and Rush Valley in Tooele County as areas that could be suitable for a new prison. The State has now asked the project team to build on the previous study's site suitability analysis by identifying the most suitable site for a new prison in the previously identified areas. In addition, the project team was asked to create conceptual plans and cost estimates for the construction of the prison on the selected site. Finally, the team was charged with comparing the cost of a 6,000 bed facility at a new site to the cost of constructing the same facility on vacant land next to the Draper Prison.

This report first explains the site selection process and briefly describes the preferred site. The report then presents a conceptual program and site plan along with preliminary infrastructure planning. Finally, the report lays out the associated costs along with a comparison of costs between a new site and expansion on the existing site.

Wikstrom Economic & Planning Consultants, Inc., is a Salt Lake City based economic, planning and real estate advisory services firm. Wikstrom offers services in economic consulting, planning, real estate development, feasibility studies, market analysis and fiscal analysis.

EXECUTIVE SUMMARY

SITE SUITABILITY ANALYSIS AND SELECTION

The 2006 prison relocation study identified three general areas that would be suitable for a new state prison. These areas included Rush Valley in Tooele County, eastern Box Elder County and northeastern Juab County. Several factors were considered in the selection process including:

- Parcel size
- Topography
- Access to water
- Distance to a hospital with emergency care
- Distance to police
- Natural resources and hazards including:
  - Existence of wetlands
  - Liquefaction potential
  - Flooding potential
- Size of surrounding employment base
- Distance to Salt Lake City (courts and University of Utah Medical Center)
- Distance to highway
- Proximity to residential areas
- Ownership

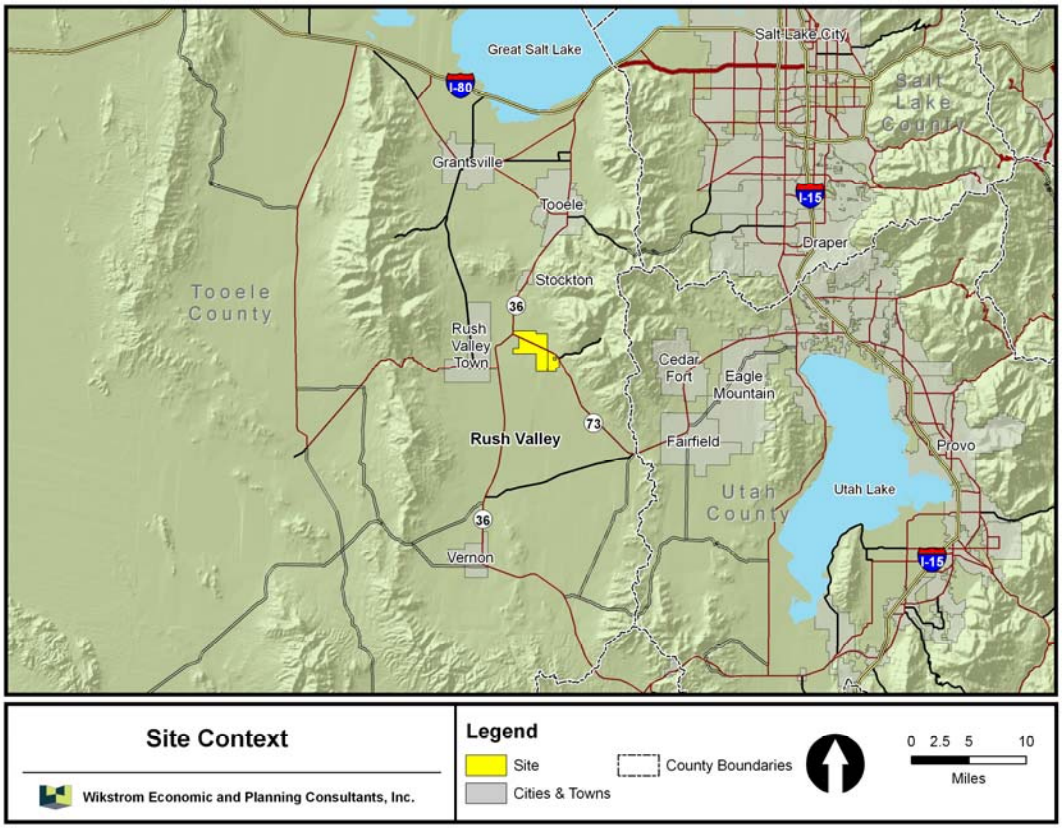


Figure S.1

These factors were used to compare the three general areas to each other and to rank individual parcels in relation to each other. The result of the analysis was to name Rush Valley as the clear winner between the three areas identified by the 2006 study. There were several parcels within Rush Valley to choose between, but one parcel, shown in its context in Figure S.1, stood out as clearly superior to all others in the valley because of its accessibility, size, and topography. The site sits at the intersection of State Highways 36 and 73 in northern Rush Valley. The selection process for this site is described in detail in Section 1 of this report.

The consultants were also asked to evaluate the possibility of locating a new prison near the Salt Lake County Landfill. The consultants found several major obstacles to locating a prison in the area. Appendix X is a report on the evaluation of the Landfill area.

ARCHITECTURAL PLANNING

An architectural planning effort has been undertaken to define the major project parameters of a prison with capacities of 6,000 and 10,000 beds. The 6,000 bed facility reflects replacement of the 4,000 beds at the Draper facility plus expansion. The 10,000 bed facility reflects the ultimate available capacity at the Draper site. Of those total bed counts, approximately 85 percent are for men and the remaining 15 percent are for women inmates. Physically separated facilities between genders are anticipated in the analysis.

The primary purpose of the planning effort is to determine the amount of land necessary to locate a prison complex and the general configuration requirements of that land. For the 6,000 bed facility, 245 acres are required for the men’s prison and 85 acres are required for the women’s prison. To increase the capacity to 10,000 beds requires a total of 380 and 127 acres respectively.

The planning process evaluated the inmate populations and the required segregations to safely house the planned population. Those requirements were aggregated into housing complexes and arranged on the site along with the necessary support spaces to provide a fully functional prison facility. Figure S.2 is the conceptual site plan for the preferred site. It includes all anticipated structures and facilities.

WATER AND WASTEWATER INFRASTRUCTURE

CULINARY WATER

Water demands for the new prison site were estimated for 6,000 bed and 10,000 bed facilities. Demands were estimated based on a usage of 115 gallons per bed per day. Using this number, demands were estimated to be:

- 400 gallons per minute (gpm) for a 6,000 bed facility.
- 800 gpm for a 10,000 bed facility.

A single water well drilled at the site could potentially produce water at flow rates of 400 to 800 gpm. (There are several wells near the proposed site that are capable of

Figure S.2: *Master Site Plan*

discharges as great as 2,250 gpm.) The site will likely require more than one well to ensure adequate supply. According to available groundwater quality data, the proposed site has total dissolved solids (TDS) concentrations of between 350 and 2,180 milligrams per liter (mg/L). TDS values greater than 1000 mg/L are likely to cause consumer complaint. Because the actual TDS value of a future well on site is unknown, the groundwater at the site will require further detailed investigations to ensure that it has a TDS level below 1,000 mg/L. The conceptual water supply infrastructure includes:

- 2(or more) wells approximately 300-600 feet deep with a 10-12 inch casing. Elevation: 5,520 feet.
- Well flow of approximately 500-800 gpm.
- 2 tanks with 750,000 gallons of storage each. Elevation: 5,540 feet.
- 12 inch water supply line. Length: 7,200 feet. Elevation drop: 160 feet.
- A water supply loop inside the fence in each complex.
- The prison complex at an elevation range of 5,400 feet to 5,300 feet.

SANITARY SEWER AND WASTEWATER

Two major wastewater treatment alternatives were investigated in this study. These include:

- An Oxidation Ditch Process with Biologic Sludge Reduction.
- Membrane Bio-Reactor (MBR) Process with Mechanical Sludge Dewatering.

Both of these options are capable of producing irrigation reuse water. An MBR system would produce irrigation water usable on food crops without any additional processes. An oxidation ditch system would produce irrigation water usable for food crops only if a filtration and disinfection step were added at the end of the process.

The conceptual wastewater system includes:

- A wastewater treatment plant with a flow rate of 0.7 million gallons per day (MGD) for a 6,000 bed facility or 1.15 MGD for a 10,000 bed facility. Elevation: 5,280 feet.
- A 15-acre, 15-foot deep wastewater storage pond for a 6,000 bed facility or a 25-acre, 15-foot deep pond for a 10,000 bed facility. Elevation: 5,240 feet.
- A gravity flow irrigation line that is approximately 4,900 feet long.
- An irrigated area of approximately 350 acres. Elevation: 5,140 feet to 5,060 feet.

STORM DRAINAGE

Storm drainage lines and detention ponds were sized to reduce post-development runoff to pre-development runoff volumes and peak flow rates. Storm water detention ponds were sized to reduce peak runoff potential to pre-development levels during a 10-year event. These pond sizes are:

- 1.9 acre-feet (5 feet deep, 140 feet x 140 feet) on the men’s side.
- 0.2 acre-feet (5 feet deep, 20 feet x 20 feet) on the women’s side.

ELECTRICAL AND COMMUNICATION INFRASTRUCTURE

ELECTRICAL LOAD ANALYSIS & POWER DISTRIBUTION

Load Analysis

Electrical demands for the new prison site were estimated in the 10 to 15 Mega Watt Range. Those demands were estimated based on a historical analysis of usage at the Draper Facility. Using this demand, PacifiCorp can service the new campus from two locations:

- At 46 kilovolts from the Tooele Substation.
- At 15 kilovolts from the Rush Valley Substation.

Under either option, service will require extensions to the new site with upgrades to the existing off-site utility infrastructure.

Power Distribution

Secondary Campus Power should be delivered from a Department of Corrections substation at 15 kilovolts with redundant feeder duct-banks throughout the campus. The main physical plant should have Co-Generation capabilities for redundancy of electrical distribution. A Combined Heat and Power Plant design would provide optimal energy conservation. Campus illumination should employ high mast lighting techniques in the 3 footcandle range for optimal nighttime security considerations.

DATA & COMMUNICATIONS

To the Site

Primary delivery of communications services to the prison site should be via fiber from the nearest utility provider. Qwest has a main switch facility in Tooele and fiber is already to the site.

Within the Site

Communications infrastructure within the site will be placed in an underground duct bank, which would encircle the site. The duct bank would include vaults for installation and maintenance.

SECURITY SYSTEMS

Perimeter Fence

Fence protection using sensor cable on the fence fabric and microwave detection zones between the dual rings of fence should be the primary method of detection. This method is currently deployed by the State in its other facilities.

Perimeter Towers & Gate Control

Two towers should control the central vehicle entrance with an additional tower at each change in direction by the fence, thus maintaining a “visual” of all fence lines.

Perimeter Cameras

Video surveillance will supplement the guard’s vision, not replace it. Cameras should be deployed to cover the same areas covered by guards; however, monitoring should be done by direct visual lookout, not by viewing video monitors, which should be relied upon primarily for their recording function.

RENEWABLE ENERGY ANALYSIS

The Rush Valley site offers significant potential for diversified renewable energy development at a 'district' energy scale. No single source similar to the geothermal resource at the present Draper Prison site, however, is likely to be identified. By applying a simultaneous strategy of 'high-performance' facility design to reduce energy demand, while developing a combination of renewable energy resources with utility grid backup, the DOC may achieve a high degree of energy self sufficiency at the Rush Valley site. As a complement to utility grid-sourced electrical and natural gas, renewable energy forms may offer a portion of the total energy demand of the prospective facility, and do so to provide some degree of energy and budget independence from future utility price fluctuations and power/fuel reliability concerns.

An inventory of potential renewable energy sources in the present analysis includes multiple forms of solar radiation capture and conversion to heat and electricity, wind electrical generation, biomass conversion to heat and electricity, geothermal heat and power, and small-scale hydroelectric generation. **Solar-thermal resources and multiple capture-conversion technologies appear, in this preliminary assessment, to promise both scale and versatility to fit the proposed project and its eventual expansion, providing both heat and electrical power, and storing a portion of thermal energy for use when needed.** Wind, biomass, geothermal and hydroelectric prospects are not understood quantitatively clearly enough to prioritize relative to other resource/technology combinations. Further, site-specific data-gathering and regional resources analyses are appropriate for these energy resources.

All possible technologies and the corresponding costs of renewable energy applications will be unique to the site, requiring further planning and engineering to define investment requirements for the various levels of renewable energy production: part of facility needs, all of facility needs, and energy production to fulfill all facility needs and to export renewable energy to the utility grid. As a hedge against future fuel price instability, planning for an excess of energy production on-site—for the DOC facility to become a 'net energy exporter,' fully utilizing the extensive property at the site—may present a State strategy worthy of serious consideration.

PROJECT COSTS

CONSTRUCTION COST COMPARISONS

Construction costs were estimated for three different scenarios, which are described below. Two scenarios are based on the same site—in Rush Valley. The only difference between the two is the size of the facility. The purpose of the third scenario is to compare the cost of constructing identical facilities in Rush Valley versus in Draper, next to the existing prison site.

The first scenario consists of a 6,000 bed facility located in Rush Valley. The facility would have seven male housing pods and one female housing pod. The estimated cost for this scenario is $984,635,000.

The second scenario represents an expansion of the first scenario. It would provide 10,000 beds in ten male housing pods and two female housing pods. It not only includes more housing pods, but also additional support structures and site development. The estimated cost for this scenario is $1,345,505,000.

The third scenario consists of a 6,000 bed facility located just west of the existing prison in Draper. This scenario would incorporate a development program identical to the Rush Valley 6,000 bed scenario. The cost of this scenario will, therefore, be very close to the Rush Valley 6,000 bed scenario. However, this scenario will cost somewhat less due to the proximity of existing utilities. The estimated cost for this scenario is $973,069,000. While this amount is somewhat less than the Rush Valley total, the difference is only about one percent of total construction cost.

OPERATIONAL COST COMPARISONS

Changing the location of the main prison facility or adding a third site to the current prison system will result in additional operational costs. Prisoner transportation expenditures would be the most affected operational cost. Sufficient data was available to project changes in transportation cost if a third site were built. Other operational costs would change somewhat; however, data needed to project other cost changes besides transportation was not available. Transportation related expenditures represent approximately four percent of the Draper facility's $73.7 million budget.

The cost of providing prisoner transportation is directly related to the change in distance between the prison and the destination. Distances were modeled between potential new sites and each of the destination types: inmate placement program ("IPP"), board of pardons and parole ("BOPP"), court appointments (e.g. appeals, hearings, custody issues, etc.), medical needs, and assignment.

Two transportation scenarios were run. One compared the cost of providing transportation for Rush Valley as a replacement for the current Draper facility (Table S.1). This scenario resulted in a 30 percent cost increase. The second scenario assumed Draper would remain as the main prison facility and Rush Valley would be added as a third prison site (Table S.2). The cost of running a third site with a total of 10,000 beds (6,000 in Rush Valley and 4,000 in Draper) is less than a full location to Rush Valley but still higher than the same number of beds at Draper. See the operational cost analysis in Section 6 for additional detail.

Table S.1. Transportation Cost Comparison

Beds	Draper	Rush Valley	Difference from Draper	Percent Change from Draper
4,000	$3,767,192	$4,890,915	$1,123,722	30%
6,000	$5,515,635	$7,162,137	$1,646,502	30%
10,000	$9,012,521	$11,704,581	$2,692,060	30%

Note: Assumes all bed are filled to 95% capacity

Table S.2. Cost of 10,000 Beds As a Three Site Scenario

Location	Beds	Cost
Draper	4,000	$4,685,881
Rush Valley	6,000	$6,177,819
Total	**10,000**	**$10,863,700**

Note: Assumes all bed are filled to 95% capacity

SECTION I: SITE SUITABILITY ANALYSIS AND SELECTION

Preliminary site selection analysis was documented in the 2006 “Evaluation of the Feasibility of Relocating the Utah State Prison” study. This study included a high level analysis of the entire state. Several criteria were used in the evaluation. In order to be considered suitable, an area must:

- Have at least 30,000 people living within 30 miles;
- Be less than 30 minutes from a hospital with a full trauma center;
- Have access to potable water;
- Be less than 30 miles from a city with a reasonably-sized police department;
- Be less than 5 miles from a major state highway or interstate;
- Have land with less than 5 percent slope; and
- Not be federal land.

The 2006 study resulted in the identification of three areas that would be suitable for a new prison—Rush Valley in Tooele County, eastern Box Elder County and northeast Juab County. The following excerpts from the study summarize the reasons for the attractiveness of the various sites.

RUSH VALLEY

“The Rush Valley area of Tooele County is located in relatively close proximity to the existing prison location. This proximity maximizes the opportunity to retain existing employees and to continue to utilize the resources offered in Salt Lake County.”[1]

EASTERN BOX ELDER COUNTY

“Proximity to major population centers and availability of suitable land augment the area’s suitability. Relatively stagnant wages, slow economic growth and higher than average unemployment may provide some incentives to accept a relocated facility.”[2]

NORTHEAST JUAB COUNTY

“This area is located relatively close to the existing facilities at Gunnison and may draw from the same labor pool, but proximity to the Wasatch Front and its attendant services make this area a highly suitable location for a full relocation. There is sufficient land that is distant from the most severe growth pressures of the Wasatch Front to remain out of the direct path of development.”[3]

All of these areas are in rural counties distant enough from highly urbanized areas that they would not suffer from the same growth pressure that has beset the Draper facility. However, they are also near enough to urban areas that a prison could be staffed and maintained without undue difficulty.

The consultant team was asked to select a site from within the three areas identified in the 2006 study. This was done using a thorough process described below.

SITE SELECTION PROCESS

INITIAL STEPS

A geographic information system ("GIS") was used to analyze suitability of each parcel within the preferred areas identified by the 2006 study. Figure 1.3 shows a graphic depiction of the site selection process, which is explained in detail in the following pages. Digital parcel information was obtained from Juab, Tooele, and Box Elder Counties. The first step was to identify parcels over 500 acres and remove all other parcels from consideration. The Department of Corrections determined that 500 acres would be the minimum sufficient area needed to accommodate a new prison with room for expansion, all associated facilities, and required perimeter open space. The removal from consideration of all parcels less than 500 acres in size put the number of possible parcels at just over 600, including approximately 400 parcels in eastern Box Elder County, 115 parcels in Juab County and 94 parcels in Rush Valley.

The next step was to apply the seven criteria from the 2006 study to the 600 parcels mentioned above. This resulted in the removal of 293 parcels for a new total of 230 parcels. Figure 1.4 shows a map of the parcels in the three counties that are greater than 500 acres in size and that meet the seven criteria from the 2006 study.

NATURAL RESOURCES AND HAZARDS

After the base criteria was applied to the parcel data, the next steps included the elimination of parcels based on a few natural resource- and hazard-related criteria. Areas removed from consideration were subject to one or more of the following:

- Flooding by the Great Salt Lake;
- Wetland coverage; or
- Liquefaction.

Great Salt Lake floodplain data was obtained from the Flood Plain Management Services Study published by the U.S. Army Corps of Engineers and digitized by the Utah Automated Geographic Reference Center ("AGRC").[4] Wetlands data was produced by the U.S. Fish and Wildlife Service as part of the National Wetlands Inventory and digitized by the AGRC and Wikstrom. Liquefaction information was produced by the Utah Geological Survey and digitized by the Utah Geological Survey and Wikstrom. Liquefaction occurs during an earthquake when ground shaking causes water-laden sandy soils to liquefy. Soil then loses it's stability and behaves like quicksand, allowing buildings to sink or tilt and utility lines to break.

***Figure 1.1**: Buildings Destroyed by Liquefaction in Niigata, Japan, 1964*

***Figure 1.2**. Natural Gas Line Ruptured by Liquefaction in Grenada Hills CA, 1994*

SITE SELECTION PROCESS

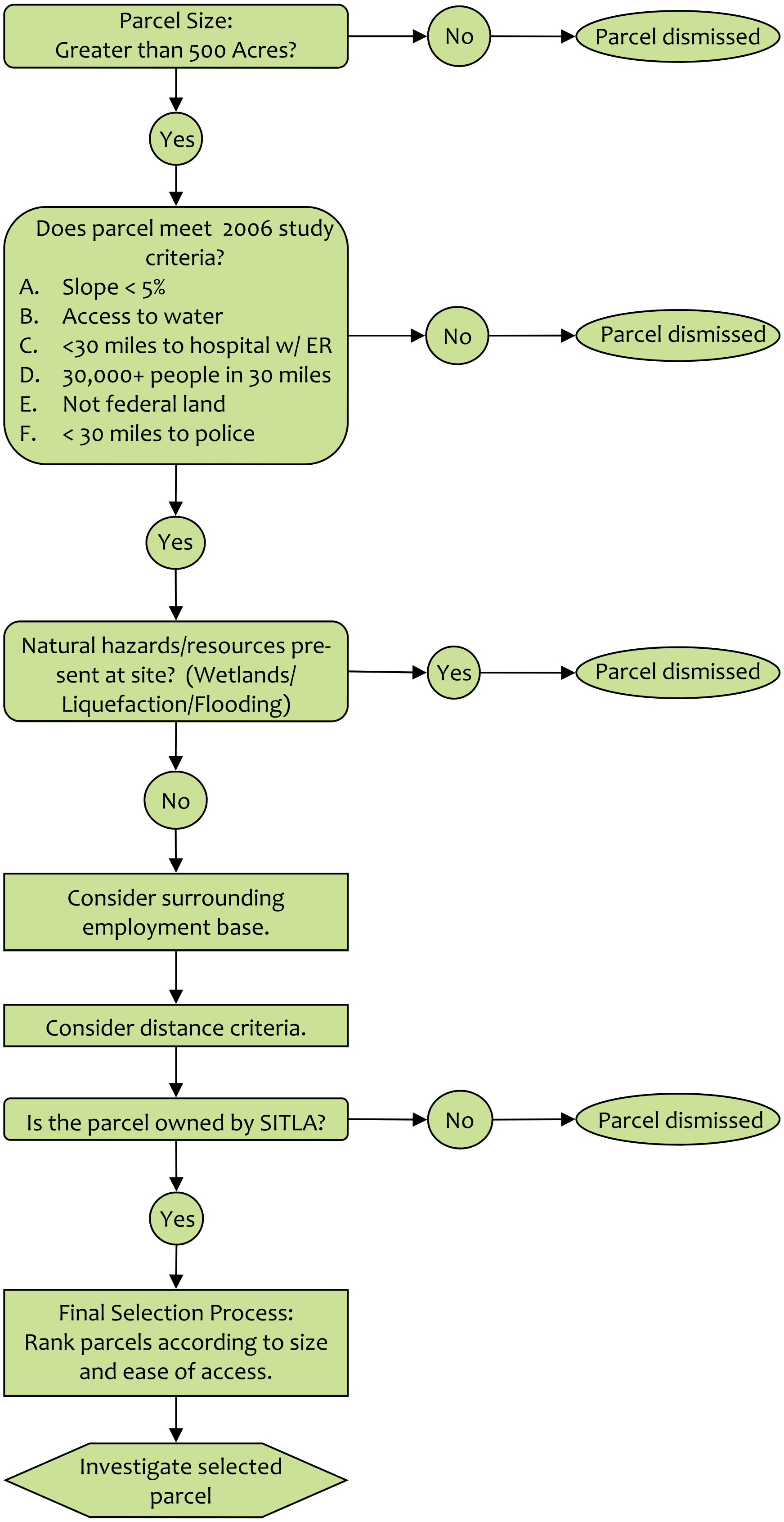
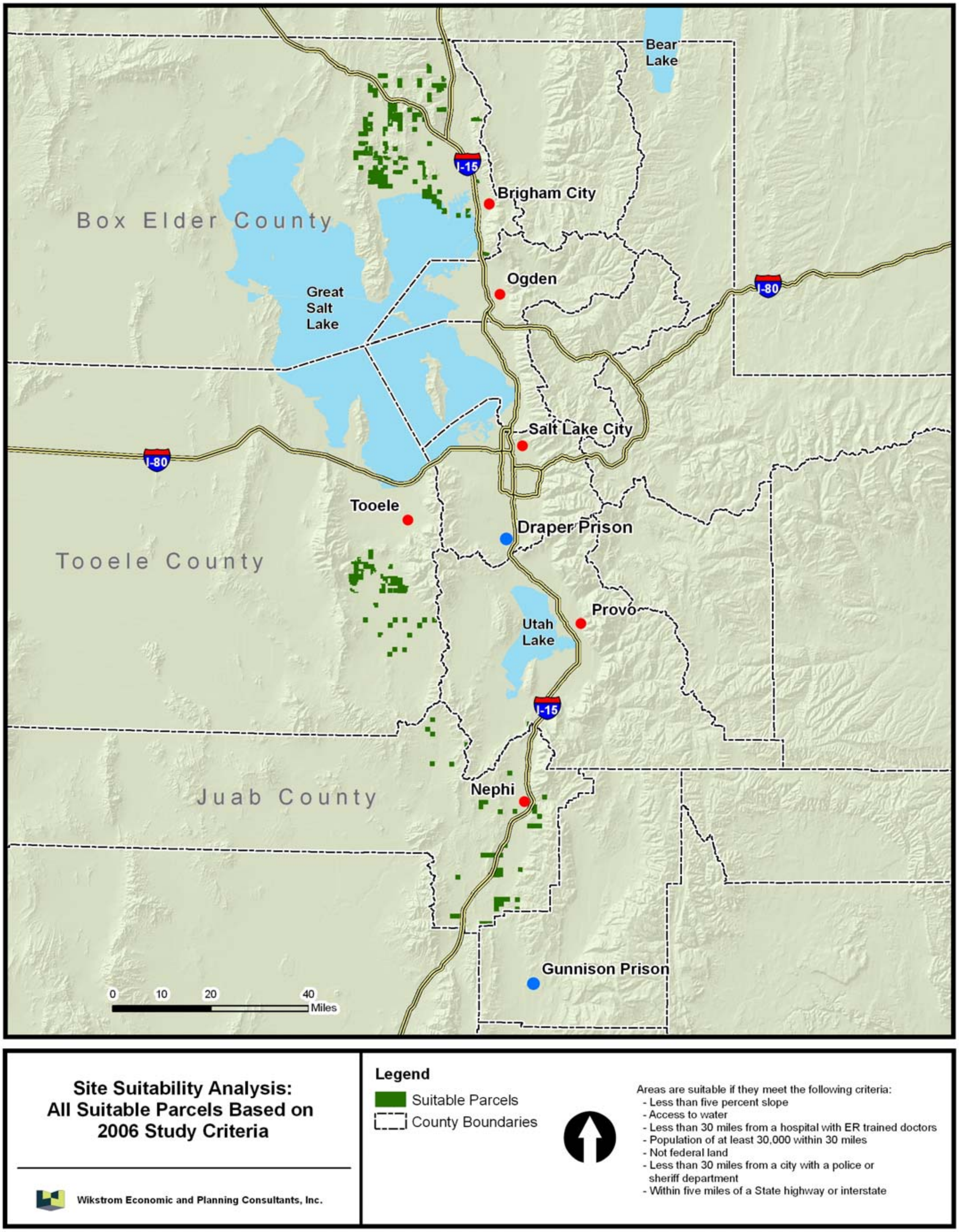


***Figure 1.3**: Site Selection Process*



Areas are suitable if they meet the following criteria:
- Less than five percent slope
- Access to water
- Less than 30 miles from a hospital with ER trained doctors
- Population of at least 30,000 within 30 miles
- Not federal land
- Less than 30 miles from a city with a police or sheriff department
- Within five miles of a State highway or interstate

Figure 1.4

Figure 1.5 shows a portion of southeast Box Elder County as an example of the application of the natural resource and hazard criteria. Wetlands, floodplain, and liquefaction potential cover much of what was considered suitable based on the high level criteria from the 2006 Study.

Figure 1.6 shows the 100 parcels still suitable after the application of the three new criteria listed above and some fine-grained adjustments for slope and other factors. The net effect of the new criteria was to substantially reduce the amount of suitable acreage in Box Elder County by removing all parcels within approximately 16 miles to the north Brigham City.

DISTANCE CRITERIA

After the application of all of the criteria discussed above, there still remained a substantial number of suitable parcels. The task then was to choose the best among them by comparing them to each other. Three important criteria were identified to further refine the selection process. These criteria included the distance to Salt Lake City courts, the distance to residential development, and the distance to a highway or freeway. These three criteria were then used to assign each parcel a rank allowing the best parcels to be identified.

DISTANCE TO SALT LAKE CITY COURTS

Figure 1.7 shows the suitable parcels and their distances in miles from the Salt Lake County District Court in Salt Lake City. This is the court most commonly used by the Department of Corrections. The distance from Salt Lake City is doubly important because the University of Utah Medical Center is also an important destination for the Department of Corrections, which sends prisoners to the Center for medical testing. The Department of Corrections contracts with the University of Utah Clinics and Hospitals to be its sole provider of specialty care, diagnostic testing and tertiary inpatient care (surgery, ICU, cardiac, etc). Because the University Medical Center is the sole provider for these services, it is important that a new prison be sited within a reasonable distance of the

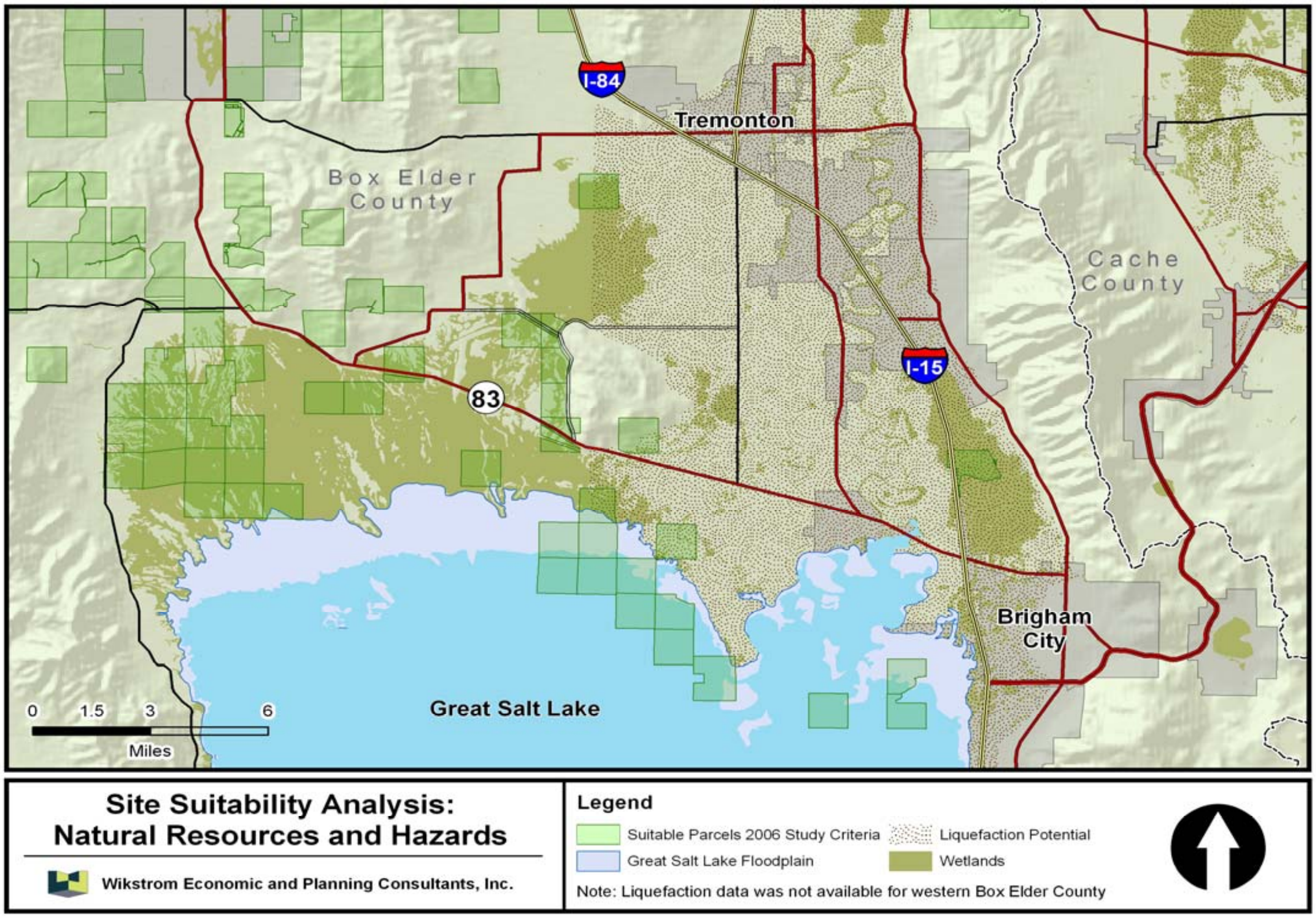
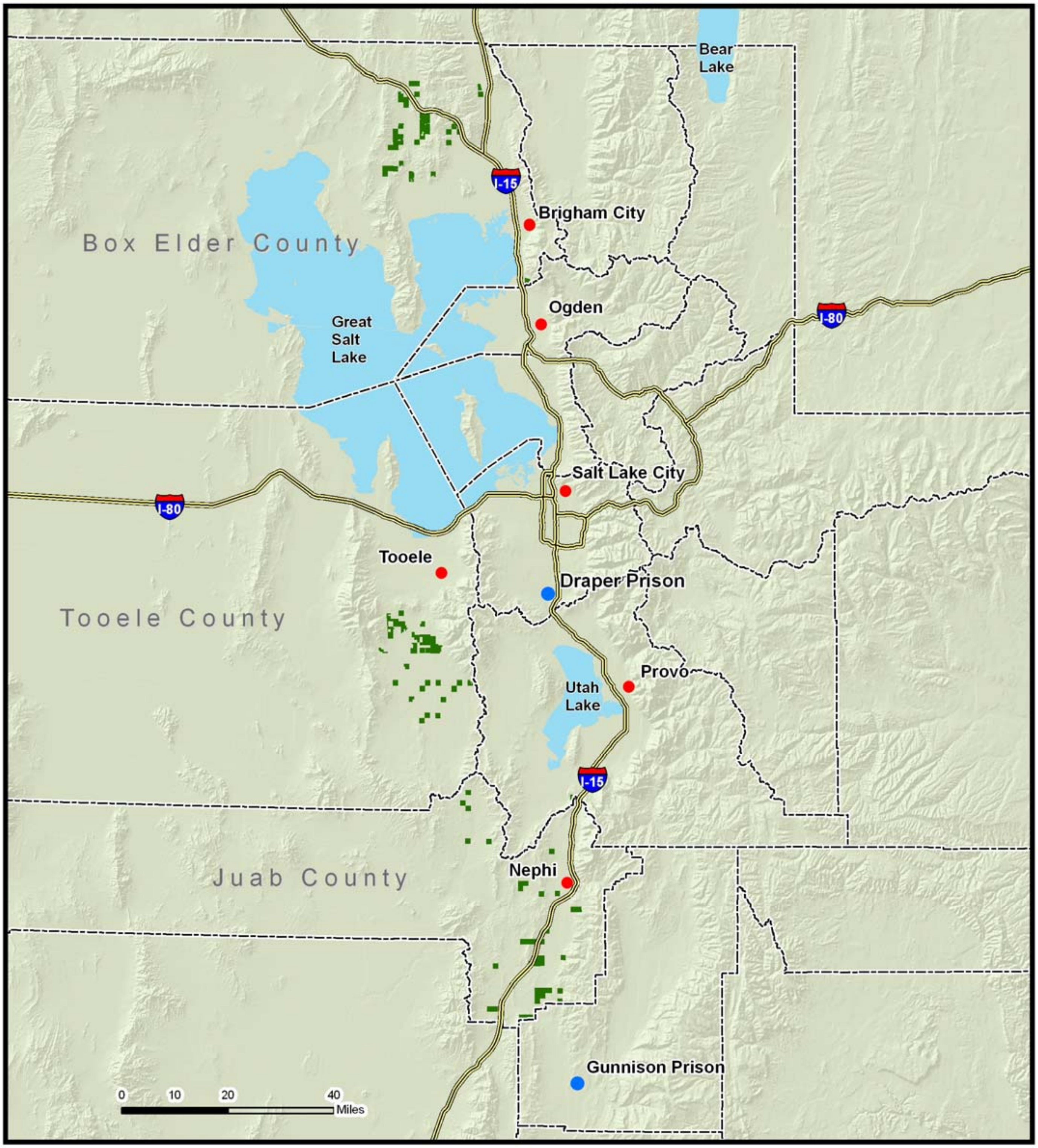


Figure 1.5



Site Suitability Analysis: All Suitable Parcels Based on 2006 Study and Additional Natural Resource and Hazard Criteria

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Legend

🟩 Suitable Parcels

⬚ County Boundaries

Areas are suitable if they meet the following criteria:
- Less than five percent slope
- Access to water
- Less than 30 miles from a hospital with ER trained doctors
- Population of at least 30,000 within 30 miles
- Not federal land
- Less than 30 miles from a city with a police or sheriff department
- Within five miles of a State highway or interstate
- Not covered by Great Salt Lake floodplain
- Not covered by wetlands
- Not subject to liquefaction

Figure 1.6

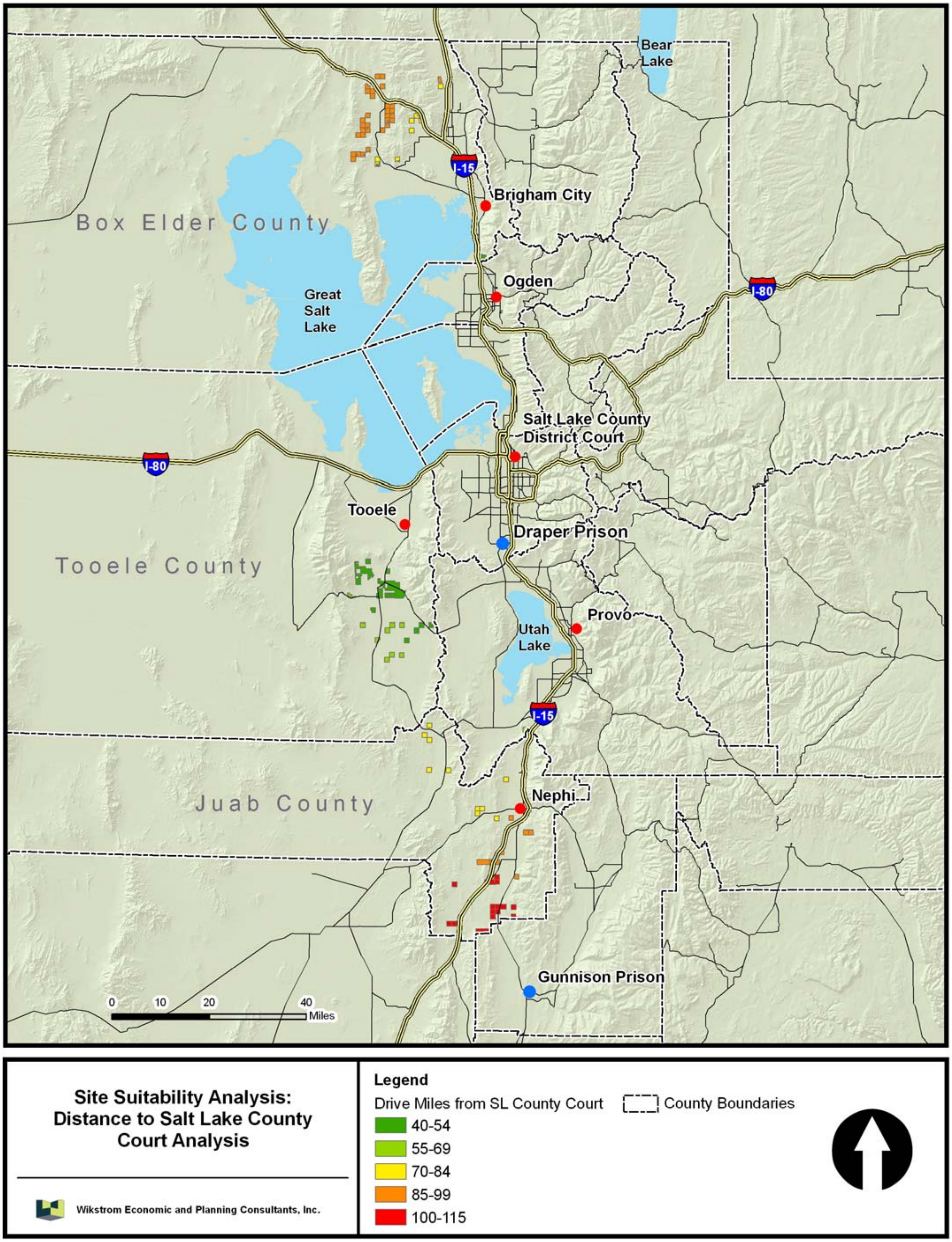

Bear Lake
I-15
Brigham City
Box Elder County
Great Salt Lake
Ogden
I-80
Salt Lake County District Court
I-80
Tooele
Draper Prison
Tooele County
Utah Lake
Provo
I-15
Nephi
Juab County
Gunnison Prison
0 10 20 40 Miles
Site Suitability Analysis: Distance to Salt Lake County Court Analysis
Wikstrom Economic and Planning Consultants, Inc.
Legend
Drive Miles from SL County Court
40-54
55-69
70-84
85-99
100-115
County Boundaries

Figure 1.7

facility. Currently the Department of Corrections assigns inmates who are more likely to need specialized medical care to the Draper site for ease of access to the University Medical Center.

DISTANCE TO RESIDENTIAL AREAS

The relative isolation of the prison site is of critical importance when it comes to the relationship between the prison and its neighbors. Frankly, very few landowners would like to have a prison next door. There has been considerable political pressure on the State to move the Draper facility entirely in favor of uses more compatible with a large urban area. There are many reasons why a prison would be an unpopular use. In the case of Draper, the argument has been made that it is not an efficient use of urban land, which could be used for higher density commercial, employment, and residential uses to serve the entire area. In addition, nearby residents do not appreciate the light pollution, perceived security risk, negative stigma and unattractive appearance of a prison. Much like an airport, a prison is usually considered an undesirable use, affecting not just its immediate neighbors, but those for miles around. While airports have more obvious detrimental effects on nearby property, such as noise and building height limitations, a prison's impacts, such as bad aesthetics and stigma, are more subtle, but still real in the eyes of landowners, whether they be residents, business owners, or real estate investors. Given these considerations, it is easy to see why it would be advantageous to locate a prison as far away from existing population centers and neighborhoods as possible, while still being within a reasonable commuting distance for employees and visitors.

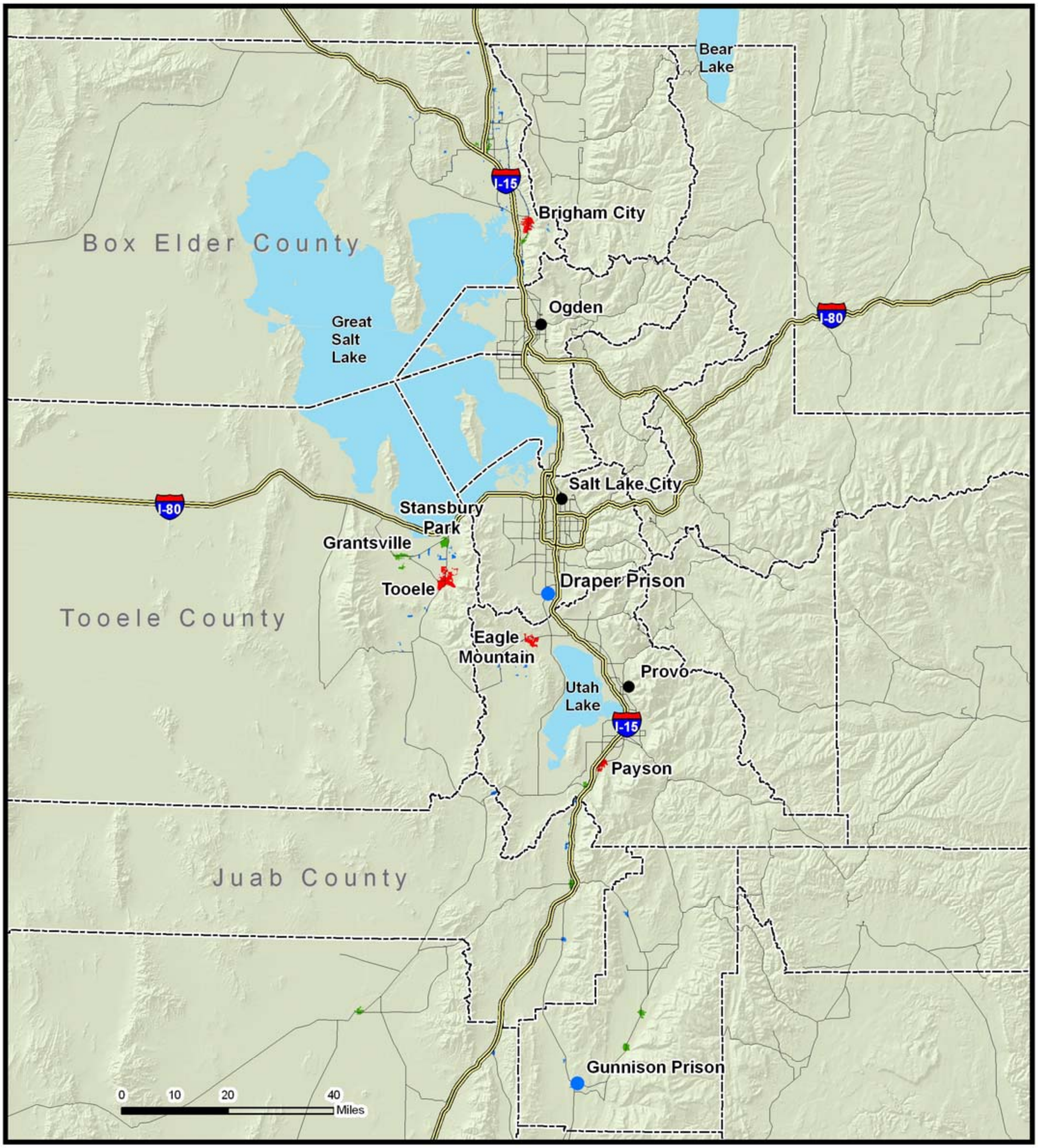
In order to compare the various site candidates by distance to existing population, land use data was obtained from the Utah Division of Water Resources, which keeps data identifying water-related land uses, including residential uses. This data was used to identify residential areas of all sizes. Residential areas were classified into three groups named Tier 1, Tier 2 and Tier 3. Tier 1 areas include communities with populations of 12,000 or greater. Tier 2 areas include communities between 3,000 and 11,999 persons and Tier 3 areas have fewer than 3,000 people. Table 1.1 shows the communities in the analysis area according to their classification and their area of influence—Box Elder County, Rush Valley, or Juab County. (Not all of the Tier 3 areas are included because they have no established names.) Communities are classified by their area of influence, not necessarily the area in which they are actually located. For example, Eagle Mountain is in Utah County, but it is listed under Rush Valley because it directly influences the potential sites in that area.

Table 1.1 Named Communities Influencing Distance to Residential Analysis

Area of Influence		
Box Elder County	**Rush Valley**	**Juab County**
Tier 1		
Brigham City	Eagle Mountain Tooele	Payson
Tier 2		
Perry Tremonton/Garland	Grantsville Stansbury Park	Delta Ephraim Manti Nephi Santaquin
Tier 3		
Bear River City Corinne Deweyville Elwood Honeyville Howell Plymouth Willard	Cedar Fort Fairfield Rush Valley Stockton Vernon	Eureka Fayette Fountain Green Levan Mona Scipio

The tier ranking system was used to account for faster growth of larger communities, which have more momentum in terms of rate of urbanization. In other words, it is generally true that growth occurs more rapidly surrounding larger communities than smaller communities. This is because larger communities have employment centers, infrastructure, retail centers, transportation networks, educational institutions and social connections, all of which people gravitate towards.

For the above reasons, location near a larger community should be considered more carefully than location next to smaller residential areas, where fewer people would be impacted by a prison. While it is important to locate near population centers for the convenience of prison operations and visitation, this consideration must be balanced with the need for a certain degree of isolation.



Site Suitability Analysis: Residential Areas Near Suitable Parcels by Size

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Legend

- 🟥 Tier 1 Residential
- 🟩 Tier 2 Residential
- 🟦 Tier 3 Residential
- ⬚ County Boundaries

Notes:
Tier 1 - Population greater than 12,000
Tier 2 - Population 3,000 - 12,000
Tier 3 - Population less than 3,000

Source: Utah Division of Water Resources - Water Related Land Use GIS Data, 2006

Figure 1.8

DISTANCE TO HIGHWAY OR FREEWAY

The final distance-related comparison criteria was the candidate parcel's distance to a highway or freeway. The nearer a parcel is to a freeway or highway the easier it is to access and the less likely major road improvements would need to be made to access the prison complex. This measurement was done using a GIS analysis which automatically assigned each parcel a number representing the distance to the nearest highway or freeway.

PARCEL RANKINGS

Parcels were ranked according to their relative suitability based on their distance to a major highway or freeway, their distance to residential areas (Tiers 1,2, and 3) and their distance to Salt Lake City, which is important because it is the location of the Matheson Courthouse and the University of Utah Medical Center, where inmates are sent for medical testing. The ranking system assigned a weight to each criterion and assigned a final score to each potential parcel. Figure 1.9 shows each criterion and its associated weight or, in other words, its relative importance. The chart is explained below.

50 percent of a parcel's score was based on its distance to Salt Lake City. The Department of Corrections feels that this criterion is of paramount importance due to the amount of prisoner transports to and from the University of Utah Medical Center and the amount of transports to Salt Lake County courts. Of all prisoner transports, roughly one quarter (about 5,700 trips in 2007) are transports to or from the Medical Center. The most common reason for transporting prisoners is for appearances at court (33 percent). State prisoners must make appearances at their courts of conviction. Nearly 40 percent of all prisoners were convicted in Salt Lake County, making it by far the most important county in terms of prisoner origination. (The next highest percentage is Weber County, which accounts for 20 percent of prisoners.) Because prisoner transport is a major expense it is important to minimize distance where possible. Because so many prisoners come from Salt Lake County it stands to reason that a new site should be as close as possible to the courts in Salt Lake City.

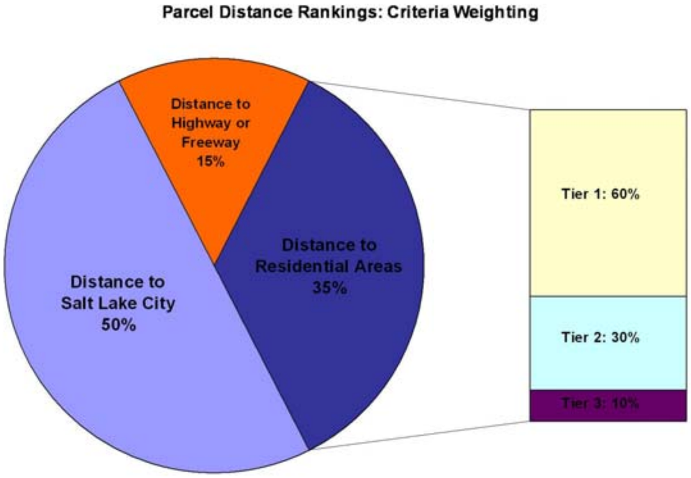


***Figure 1.9**: Parcel Distance Rankings*

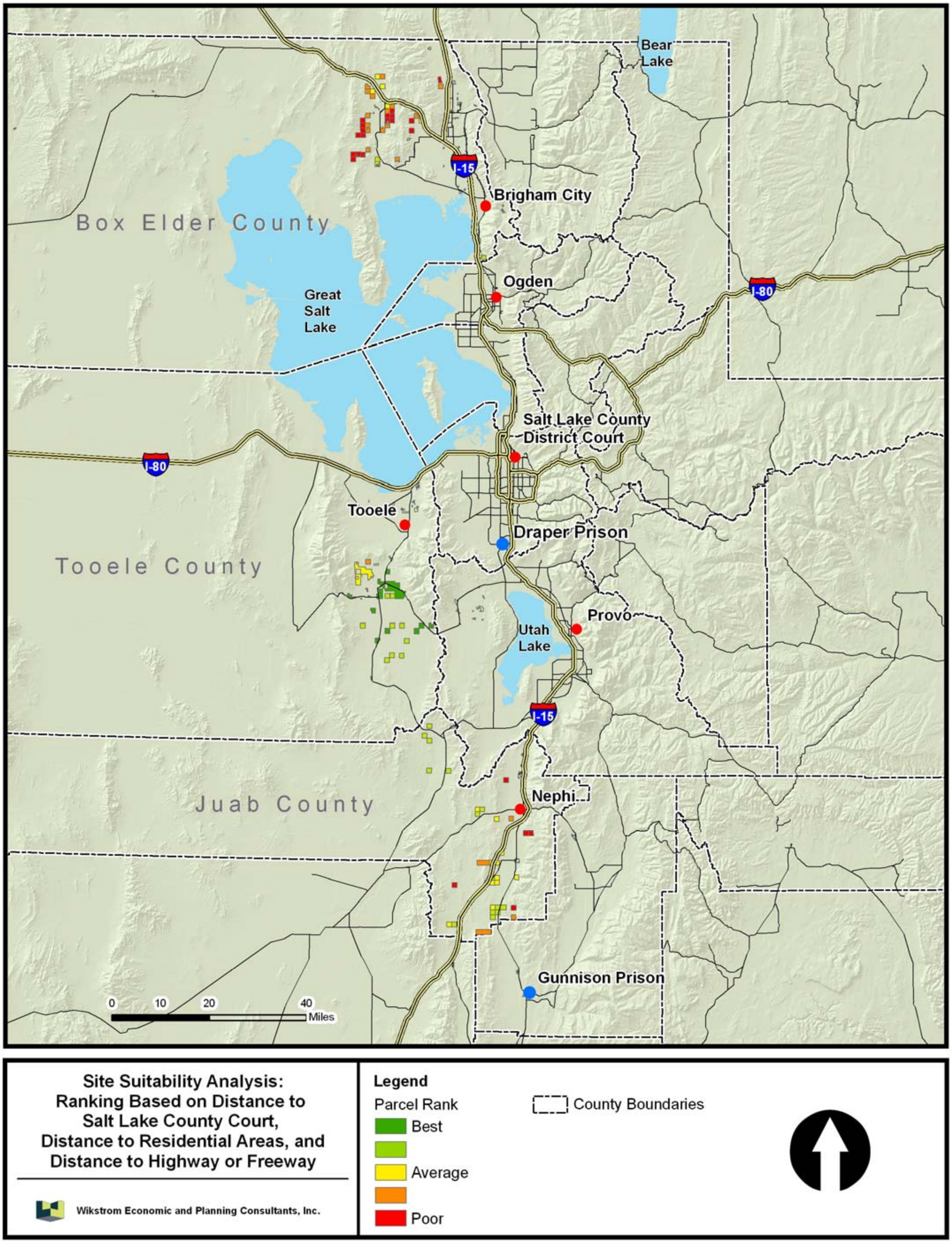
35 percent of a parcel's score was based on its distance to residential areas. As mentioned before, it is important to avoid conflict with neighboring land uses as much as possible to minimize negative visual and other perceived impacts on neighboring property owners.

The Department of Corrections realizes that "nobody wants a prison in their backyard," hence this criterion's high weighting. This criterion is broken out into three tiers as mentioned previously. Tier 3 areas (the smallest) represent 10 percent of the "distance to residential areas" score. Tier 2 areas represent 30 percent, and Tier 1 areas (the largest) represent 60 percent. Tier 1 areas are most important because they have the most growth inertia; that is, they consume land more quickly as development occurs. A prison within a mile of a Tier 1 community has a greater danger of urban encroachment that if they were within a mile of a Tier 2 or Tier 3 community.

The last criterion—distance to highway or freeway—represents 15 percent of a parcel's total score. This access criterion further refines a similar criteria from the first study, which was that a feasible parcel must be located within five miles of a major highway or freeway.

A state prison sees a heavy amount of traffic and must be easily accessible. New roads can be built to access a site, but they are expensive—approximately $2 million per mile for a two land road according to Parametrix.

Figure 1.10 maps the results of the distance ranking analysis. The top ten sites are all located in Rush Valley.



Site Suitability Analysis: Ranking Based on Distance to Salt Lake County Court, Distance to Residential Areas, and Distance to Highway or Freeway

Figure 1.10

PROXIMITY TO EMPLOYMENT BASE

A 6,000 bed prison would require close to 2,000 employees. With such a high number of employees it is critical that the prison be located such that it can access a large labor pool. It is therefore useful to compare Box Elder County, Juab County and Rush Valley in terms of the size of labor pool within a reasonable distance. A comparison between probable commute areas for each proposed area was conducted to estimate the number of persons accessible under the GOPB's 2008 Sub-county Population Projections. In order to do this hypothetical sites were chosen in northern Rush Valley, southeast Box Elder County and Northeast Juab County. In addition to clarifying the general accessibility of each site to possible employees, the population analysis also gives an indication as to the availability of services, and accessibility to the visiting public.

Commute areas were defined based on two scenarios: travel distance and travel time. Thus, the area of land that could be reached with 30 minutes travel time, or conversely, within 30 miles of travel distance along the existing network of roads was used as a point of comparison for general accessibility of each of the three hypothetical sites. Six commute areas for each site were created to account for travel within 30, 60, and 90 minutes of the site and 30, 60, 90 miles of travel from each site. Commute areas were created through a GIS analysis of travel along the existing road network. Travel impedances were estimated conservatively for each major class of roads (i.e. Interstate Highways would experience average travel speeds of 65 mph and major arterials would allow average travel speeds of 45 mph).

The GOPB's sub-county projections are created for every municipality in the state and the remaining balance of population living within unincorporated areas of the counties. This information was used in conjunction with the existing municipal boundaries and unincorporated county lands to create a map of population density. This map was created by excluding public lands and lands not considered within a classification of land uses that assesses access to urban, residential or irrigation water facilities developed by the Utah Division of Water Resources. It is assumed these areas not excluded by the criteria above will accommodate the majority of future population growth. The boundaries of commute areas were then overlaid and the total population within these boundaries calculated.

The table below shows that Rush Valley is the most accessible site in terms of the overall population both now and in the future. This is particularly true for the 30 minute/30 mile and 60 minute/60 miles commute area boundaries, where most employees will come from. The Rush Valley site has the advantage of having nearly two and a half times as many people within a 60 minute commute as the Box Elder County site and four and a half times as many as the Juab County site.

The Rush Valley area is within a half hour commute of several communities including Tooele, Grantsville, and Stansbury Park as well as the sparsely populated area to the south that includes Rush Valley and the extreme western portion of Utah County. An hour's commute time opens up the accessible area considerably and includes all of the area along the Wasatch Front from Bountiful in Davis County to Lindon in Utah County.

Table 2. Projected Population within Service Areas (Designated by Travel Time and Distance) 2010 and 2020

		2010			2020		
		30	60	90	30	60	90
Distance (Miles)	Box Elder County	45,000	613,000	1,374,000	53,000	739,000	1,610,000
	Juab County	46,000	505,000	1,656,000	71,000	633,000	2,043,000
	Rush Valley	**124,000**	**1,693,000**	**2,327,000**	**174,000**	**2,032,000**	**2,839,000**
Time (Minutes)	Box Elder County	19,000	553,000	1,672,000	22,000	664,000	1,960,000
	Juab County	20,000	301,000	1,442,000	31,000	383,000	1,783,000
	Rush Valley	**42,000**	**1,381,000**	**2,288,000**	**60,000**	**1,682,000**	**2,780,000**

Source: Wikstrom, Governor's Office of Planning and Budget

SITLA SELECTION

A final criterion for selection was that the property be owned by the state of Utah, and specifically by the School and Institutional Trust Lands Administration ("SITLA") for ease of acquisition. An internal transaction between SITLA and the Department of Corrections would ensure the best outcome for the state. SITLA has provided detailed data regarding the selected site, but has not yet been formally approached regarding a potential transfer of ownership.

By excluding all non-SITLA land the number of candidate sites was reduced drastically from 100 to 15. There were no SITLA parcels in Box Elder County that met the necessary criteria and only two SITLA parcels in Juab County met the criteria. Only one of the Juab County sites was reasonably accessible in comparison with other candidate sites. The remaining 13 parcels were located in Rush Valley.

FINAL SELECTION

When considering all of the distance factors, the availability of SITLA land and the number of employees within the reach of the various areas (Box Elder County, Juab County, and Rush Valley) the weight of preference falls squarely on Rush Valley. Figure 1.11 shows a close-up of the five top ranked sites, which are all located in Rush Valley. (These sites scored closely enough that the scoring differential between them is immaterial.) Any of these five sites could potentially accommodate a prison, however, the selected site (site A on the map) is the best for two main reasons. It is by far the largest, and it is the most accessible.

PARCEL SIZE

A larger parcel is beneficial for a few reasons. First, it allows more flexibility for facility expansion and placement. Second, it allows for utilization of sustainable technologies, such as irrigated land for disbursement of treated wastewater. Third, a large site allows for adequate water pressure to serve the facilities without the construction of water towers, which are more expensive to build and operate than ground-level storage tanks. The large site thus allows both significant elevation change, which allows the site to be self sustaining in terms of water usage, and a gentle slope with minimal topography (important for security reasons). In the case of the preferred site wells can be placed on the eastern edge of the site, creating pressure for use at the prison complex further to the west. Wastewater can then be gathered, treated, and stored for use on irrigated farmland onsite to the west of the main prison building. This farmland can be worked by lower security prisoners. All of this would not be possible on smaller sites in Rush Valley. An additional benefit of having an extraordinarily large site is that unused land can act as a buffer between neighboring land and the prison complex, thus reducing the negative impact of a prison.

ACCESSIBILITY

The selected site (A) is most preferable in terms of accessibility because of its location at the intersection of two highways running into the valley from Tooele and from Utah County. Of the final candidates, it strikes the best balance between accessibility for employees and being located a comfortable distance from residential areas. The preferred site also benefits from having a low-traffic highway bisect the site. This road, although public, could essentially act as an internal road, allowing fast and easy access to multiple separate facilities on the site such as the men's prison, the women's prison, water tanks, irrigated land, wastewater treatment facilities, and others.

Site B has three problems. First, it is closer to the town of Rush Valley than the preferred site. Second, railroad tracks run between the usable portion of the site and highway 32, which would be used to access the site. Third, the site has some topography that could be a security issue.

Site C is located nearly a mile from Highway 32, necessitating the construction of an access road (which would cross railroad tracks) at a cost of roughly $1.8 million. Additionally, Site C would be a much farther drive coming from either Tooele or Utah County.

Site D is closer to the employment base in Utah County, but farther from Tooele, the likely future location of many prison employees. Site D also suffers from an irregular shape, which includes an odd island of BLM property in the middle of the parcel. A final drawback to Site D is that it sits squarely in the middle of the Five Mile Pass Recreation Area, a popular ATV recreation area managed by the Bureau of Land Management.

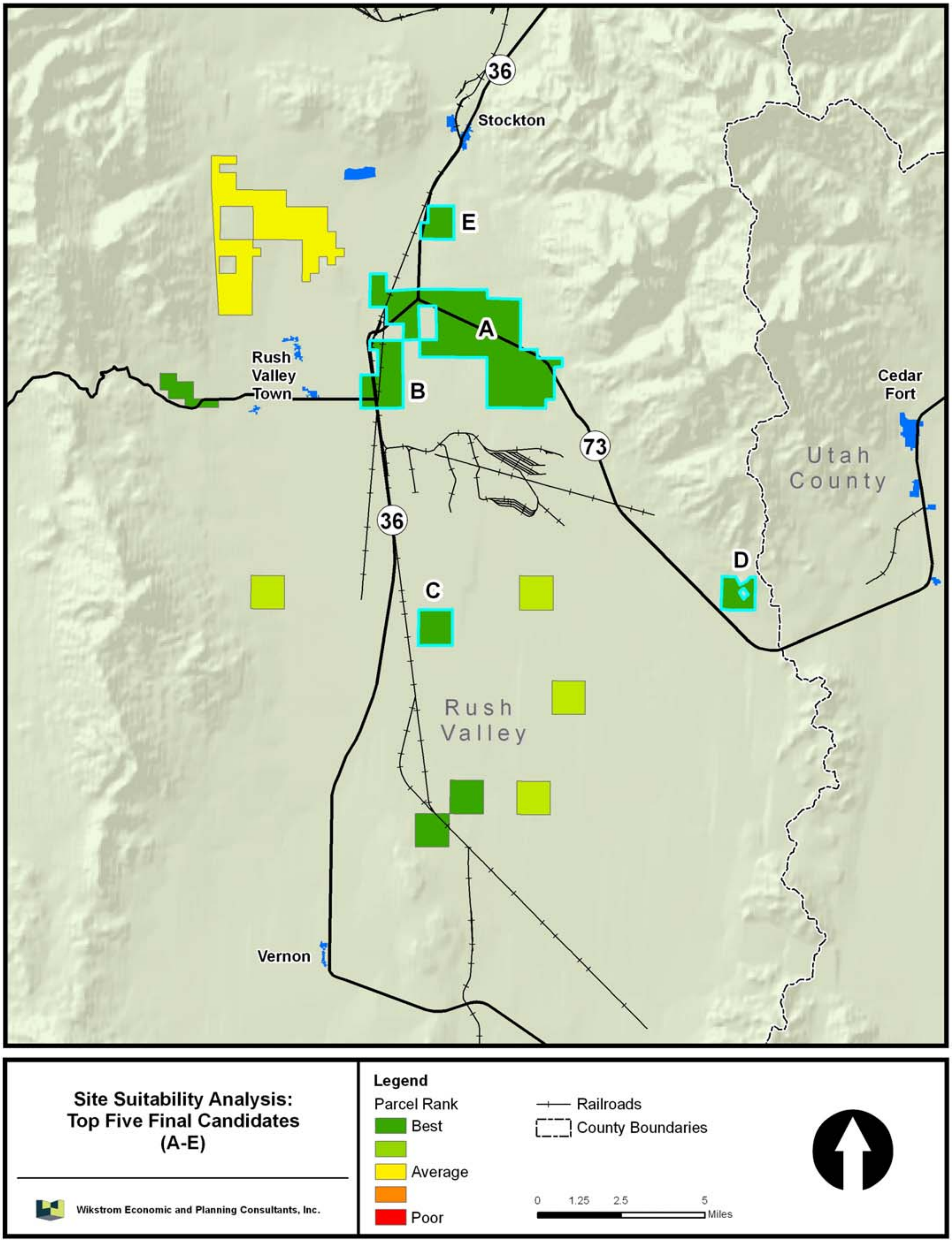

36
Stockton
E
A
Rush Valley Town
B
73
Cedar Fort
Utah County
36
D
C
Rush Valley
Vernon
Site Suitability Analysis: Top Five Final Candidates (A-E)
Wikstrom Economic and Planning Consultants, Inc.
Legend
Parcel Rank
Best
Average
Poor
Railroads
County Boundaries
0
1.25
2.5
5
Miles

Figure 1.11

Site E is closer to Tooele, but farther away from Utah County. Site E is also uncomfortably close to the small town of Stockton.

SELECTED SITE

PROPERTY LOCATION

The selected site is located in Rush Valley, which is a very sparsely populated area south of the city of Tooele. The site itself is about nine and a half miles south of Tooele. There are three small municipalities in the valley: Rush Valley, Stockton, and Vernon. The valley has a population of roughly 1,600 people according to estimates published by the Tooele County Planning and Economic Development Division. The closest town is Rush Valley, the residential areas of which are about 3.5 miles from the site in a straight line. Distance along roads would be approximately 5.5 miles. The next closest town to the site is Stockton, the residential areas of which are about 4.5 miles north (travel distance) from the site. To the south the site borders the Deseret Chemical Depot, which is discussed later in the Property Investigation section. Figure 1.12 is a photograph of the property taken from Highway 73 looking east.

Figure 1.12

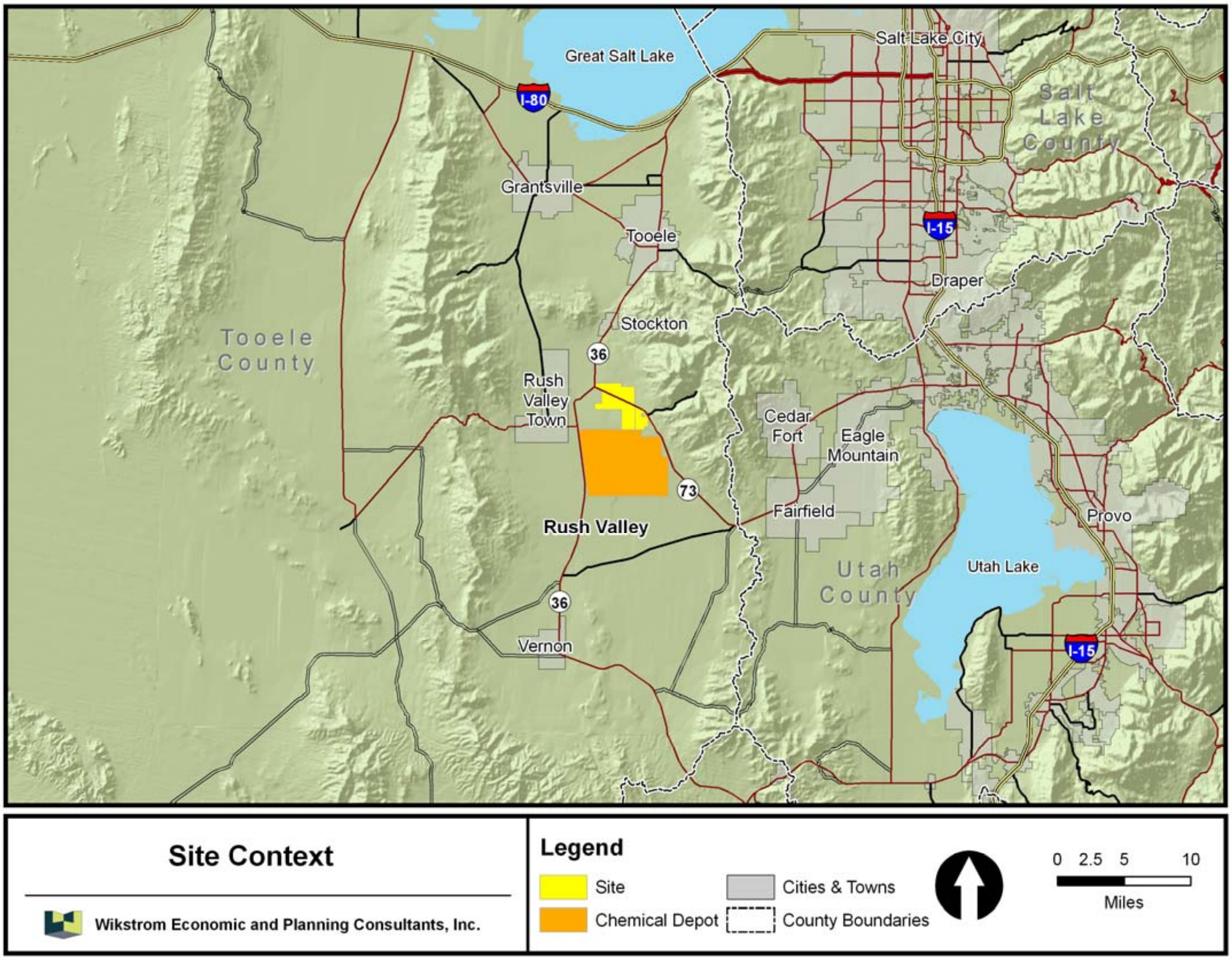


Figure 1.13

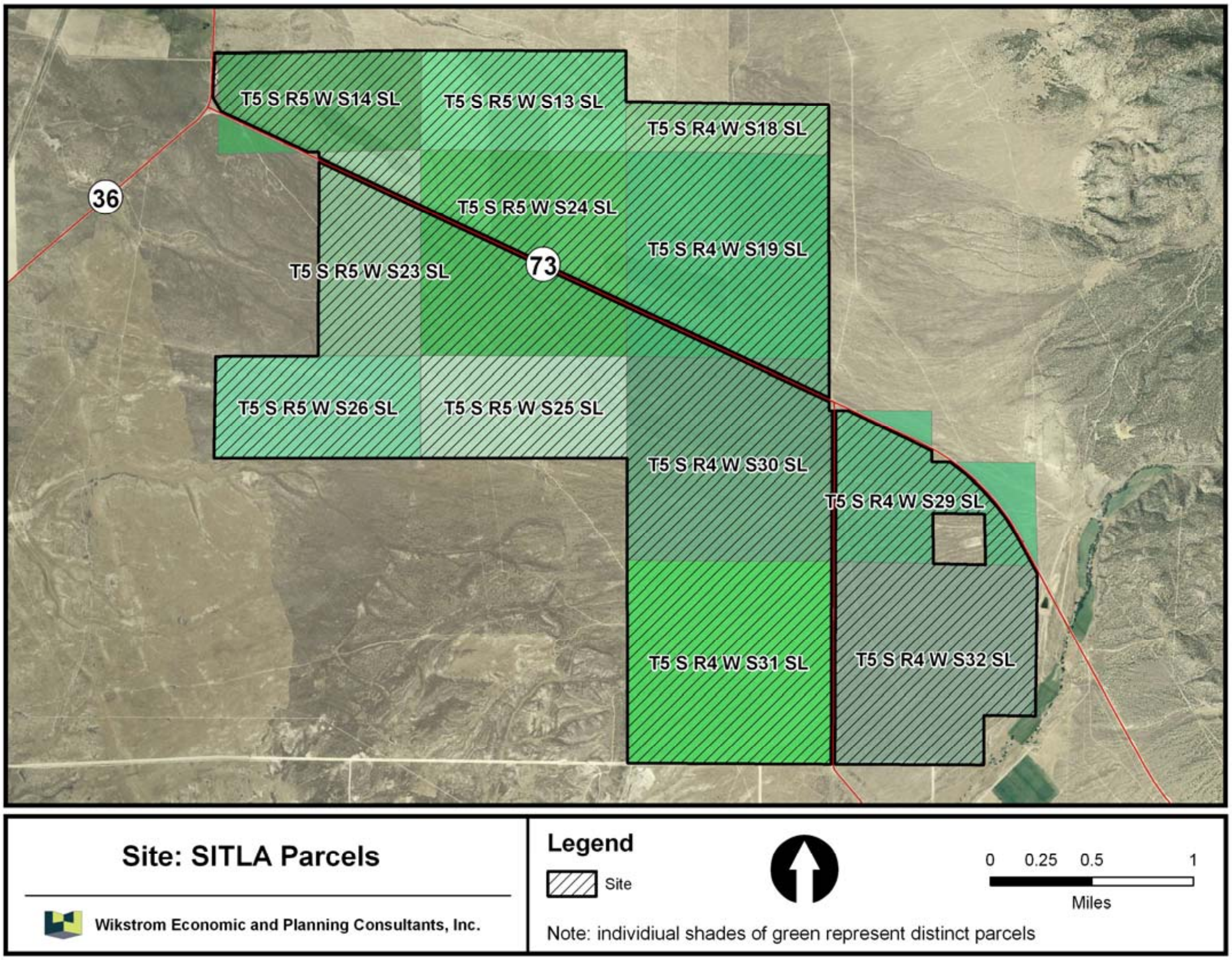


Figure 1.14

Figure 1.13 shows the site in a regional context. The map brings into sharp focus the locational benefit of the site, which is the fact that it is close to the State's largest employment base, yet located in a very rural location surrounded by natural barriers.

The property itself if owned by SITLA, which parcels its land according to a geographical system that includes townships ranges and sections. Figure 1.14 shows the individual parcels within the defined site. All but two of the parcels shown fall completely within the site. Table 3 contains a detailed description of the site in its entirety. It is composed of 12 distinct parcels and contains approximately 5,161 acres.

Table 3. Parcels Identified for Prison Site

Parcel ID (Township, Range, Section, Meridian)	Legal Acres Entire Parcel	Estimated Acres Within Site for Partial Parcels	Portion Included in Site
T5 S R5 W S14 SL	320.00	287	Portion north of SR-73
T5 S R5 W S13 SL	320.00		All
T5 S R4 W S18 SL	160.10		All
T5 S R5 W S23 SL	320.00		All
T5 S R5 W S24 SL	640.00		All
T5 S R4 W S19 SL	640.02		All
T5 S R5 W S26 SL	320.00		All
T5 S R5 W S25 SL	320.00		All
T5 S R4 W S30 SL	640.16		All
T5 S R4 W S29 SL	360.00	274	Portion south of SR-73
T5 S R4 W S31 SL	640.35		All
T5 S R4 W S32 SL	600.00		All
Total Acreage		**5,161**	

Source: SITLA, Wikstrom

PROPERTY INVESTIGATION

The Utah School and Institutional Trust Lands Administration ("SITLA") was interviewed in September of 2008. SITLA indicated there were no water rights associated with the subject property.[5] It was not aware of any problems associated with the property that could inhibit construction of buildings. SITLA allows grazing on some properties by permit; however, these permits can be revoked simply by giving 30 days notice to the permit holder. The property is not currently being leased to any organization. As mentioned previously, as of the publication of this document SITLA has not been formally made aware of the Department of Corrections' interest in the selected site.

Water

As part of the site selection process a preliminary analysis of water availability and quality was performed. A detailed discussion of water availability and quality is given in Section 3 of this report. In summary, the water available at the selected site is normal and would require no unusual treatment in order to make it potable.

Substantial water rights would need to be purchased in order to locate a prison in Rush Valley. The challenge in this case is that Rush Valley is a closed basin; new water rights in the magnitude needed for a prison cannot be issued by the State, but must be purchased from current owners. According to research done by Wikstrom and Stantec, the DOC could expect to pay between $10,000 and $15,000 per acre-foot. Using an average of $12,500 per share, the price for water rights for a 6,000 bed facility would be approximately $9.6 million.

Infrastructure

A fiber optic line runs along Highway 73. A natural gas line with sufficient capacity to serve the prison also parallels Highway 73. Rocky Mountain Power intends to run a major new power corridor through Rush Valley in the next few years. The corridor would provide sufficient power and redundancy to the site.

Deseret Chemical Depot

The Deseret Chemical Depot is located immediately to the south of the site on a plot of land nearly 20,000 acres in size. There are two main access roads to the Depot—one on the north and one on the east. As shown on Figure 1.15 the northern access road travels through the selected site for about 1.75 miles before reaching the Chemical Depot property.

The depot has stored chemical weapons since the 1940's and has been destroying the weapons since 1996. In 1997 the United States agreed to destroy all its chemical weapons by 2007, but in 2007 the goal was far from achievement. In April of 2006 the Organization for the Prohibition of Chemical Weapons granted a five-year extension for the U.S. to destroy all chemical weapons.[6] The Deseret Chemical Depot is ahead of this schedule and anticipates the destruction of all its chemical weapons by August of 2011, at which time the closure process will begin.[7] While the Deseret Chemical Depot is on schedule to meet the 2012 deadline, other facilities in the U.S. are not. A congressional mandate that all chemical weapons be destroyed by 2017 triggered a response from Pentagon that this could only be done by transporting chemical weapons.[8] This has fueled speculation that additional weapons could be brought in from other states to be incinerated at the Deseret Chemical Depot; however, this is highly unlikely because transportation of chemical weapons is politically unpopular and currently against federal law.[9] In addition, the 2005 Base Closure and Realignment Report stated, "there is no additional chemical demilitarization workload slated to go to Deseret Chemical Depot."[10] It appears the Deseret Chemical Depot will cease operations well before a new prison would begin operating.

After the Deseret Chemical Depot has closed the Depot property will continue to be used by the U.S. Army as a storage facility for conventional weapons. In fact, the Tooele Army Depot has already started using a portion of the site for conventional weapons storage.[11] In 2005 the Defense Base Closure and Realignment (BRAC) Commission made some recommendations affecting the Tooele Army Depot and Deseret Chemical Depot. First, BRAC recommended the Deseret Chemical Depot be closed and that its storage buildings be used by the Tooele Army Depot. Second, BRAC recom-

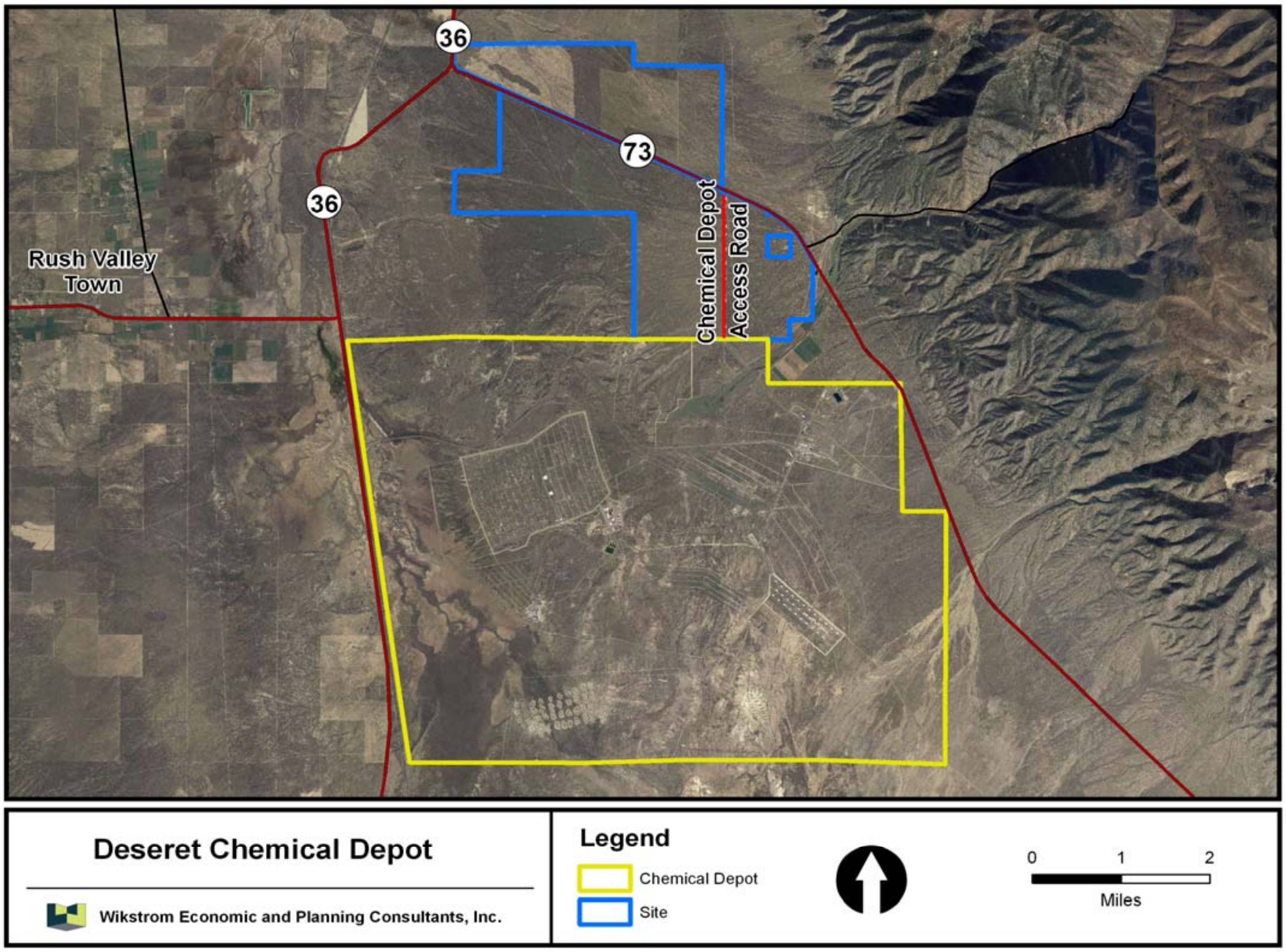


Figure 1.15

mended weapons storage operations from two facilities (Sierra Army Depot, CA and Hawthorne Army Depot, NV) be relocated to the Tooele Army Depot to increase efficiency.[12] BRAC's actions seem to indicate the Tooele Army Depot is increasing in importance and that the current Deseret Chemical Depot site will be used as a conventional weapons storage facility for a long time to come.

Land Use Regulations

The State is not bound by local land use regulations; however, local land use regulations can be helpful in identifying potential issues and hazards that may arise with development. Some communities have enacted laws to mitigate impacts of neighboring hazardous uses. For example, West Valley City enacted an "Overpressure Zone," which requires new construction within a certain radius of the ATK Launch Systems complex to use windows strong enough to withstand shock waves and fragments. The Tooele County Planning and Zoning Division was contacted and asked if there were any special regulations for building next to the Deseret Chemical Depot or the Tooele Army Depot, which has begun using the Deseret Chemical Depot's empty storage buildings for conventional weapons storage. The Division responded that there were no special regulations for building next to either the Deseret Chemical Depot or the Tooele Army Depot.[13]

SECTION I - FOOTNOTES

[1] State of Utah. Division of Facilities Construction and Management, Department of Administrative Services, Department of Corrections. *Evaluation of the Feasibility of Relocating the Utah State Prison*. Salt Lake City. 2006.

[2] State of Utah. Division of Facilities Construction and Management, Department of Administrative Services, Department of Corrections. *Evaluation of the Feasibility of Relocating the Utah State Prison*. Salt Lake City. 2006.

[3] State of Utah. Division of Facilities Construction and Management, Department of Administrative Services, Department of Corrections. *Evaluation of the Feasibility of Relocating the Utah State Prison*. Salt Lake City. 2006.

[4] United States. Army Corps of Engineers Sacramento District. *Great Salt Lake Flood Plain Management Services Study*. 1997.

[5] Burton, Kay. SITLA. personal interview. 12 September, 2008.

[6] U.S. Army Chemical Materials Agency. *Tooele Deseret Chemical Depot.* Aberdeen Proving Grounds Edgewood Area, Maryland.

[7] Blauser, Amy. Tooele Chemical Stockpile Outreach Office. personal Interview. 9 September, 2008.

[8] Brook, Tom. “Chemical Weapons Transport Plan Draws Fire.” USA Today July 2, 2008: http://www.usatoday.com/news/military/2008-07-01-chemweapons_N.htm

[9] Grieser, Alaine. Deseret Chemical Depot Public Affairs. personal interview. 15 September, 2008.

[10] United States. Department of Defense. *Base Closure and Realignment Report*. May 2005.

[11] Grieser, Alaine. Deseret Chemical Depot Public Affairs. personal interview. 15 September, 2008.

[12] United States. Department of Defense. *Base Closure and Realignment Report*. May 2005.

[13] Hilderman, Matthew. Tooele County Planning and Zoning Division. 12 September, 2008.

SECTION II: ARCHITECTURAL PLANNING

METHODOLOGY

This study is based on an initial prison population of approximately 6,000 and a final population of approximately 10,000. Initial discussions were conducted with Utah Department of Corrections (UDOC) representatives to determine the gender mix and management segregations for each of those population totals. Based on those discussions, it was determined that the gender targets would be 5,000 male beds and 1,000 female beds for the first phase and linear extension of those counts for the second phase. Phase one represents a complete replacement of the existing facilities in Draper. Phase two represents estimated population growth over the 50 to 100 year life of a new facility.

A conceptual building program has been developed to determine the scope of the two phases of the project. The determining factor to develop the program is the number of secure beds served, which leads to the amount of support, both secure and non-secure, administration, and program spaces necessary. Once the bed counts are established, the management segregation and housing type can be determined and a housing scenario can be developed.

HOUSING CONFIGURATION

The basic housing planning modules used for the study are the 192 bed cell module and the 288 bed dorm module currently being utilized in the expansion at the Gunnison site. The 192 module consists of 6 units, each comprised of 16 double-bunked cells and supporting outdoor recreation space (Figure 2.1). The 288 module is comprised of 6 units, each with 4 – 12 bed dorm cells and an exercise room (Figure 2.2). Application of the 192 versus the 288 module is based on management segregation requirements. UDOC uses Levels 1 through 5 to describe the behavioral characteristics of the inmate population, where Level 1 are the least manageable and present the highest risk to staff, other inmates and themselves, and Level 5 is the lowest risk. Level 1 inmates have the fewest privileges and are held in the closest confinement, while Level 5 inmates have greater privilege and live in less confinement. Thus, Levels 1, 2 and some 3's are housed in cells. The rest of the 3's, Level 4 and Level 5 inmates are housed in dorms.

Housing modules are grouped by fours into housing complexes, with support spaces common to all housing forming a core around which the modules are arranged. A housing complex is best suited for a single management segregation or segregations that are closely aligned. For example, Level 1's and 2's are often considered together, and although inmates of those two levels would not cohabitate in a housing unit, they might share a module, and would certainly be acceptable as individual modules within a complex. Thus, the 192 and 288 modules can be arranged in any combination to form housing complexes that provide the right segregation mix for the intended population (Figure 2.3).

In addition to the General Population Housing, counts for residential medical beds, mental health beds and administrative segregation were added to the totals to establish a total bed count. For the sake of this study these beds are illustrated within the 192/288 module parameters. It is likely that some of this population's housing, particularly residential medical and acute mental health, would be organized somewhat differently than illustrated. However, for the purposes of establishing the amount of site needed for the proposed facility and estimating costs, the 192/288 modules provide a reasonable approximation.

Once the gross bed counts were established, the populations were divided utilizing management segregations based on existing UDOC standards. Those break downs are described in Table 2.1.

Utilizing these guidelines, the bed count for each gender population was distributed into appropriate management segregations and housing types mathematically. These raw calculations were then adjusted to match the bed count of the basic unit of the assigned housing type. For example, single bunked cells occur in 16 bed units, double bunked cells occur in 32 bed units and dorms in 48 bed units.

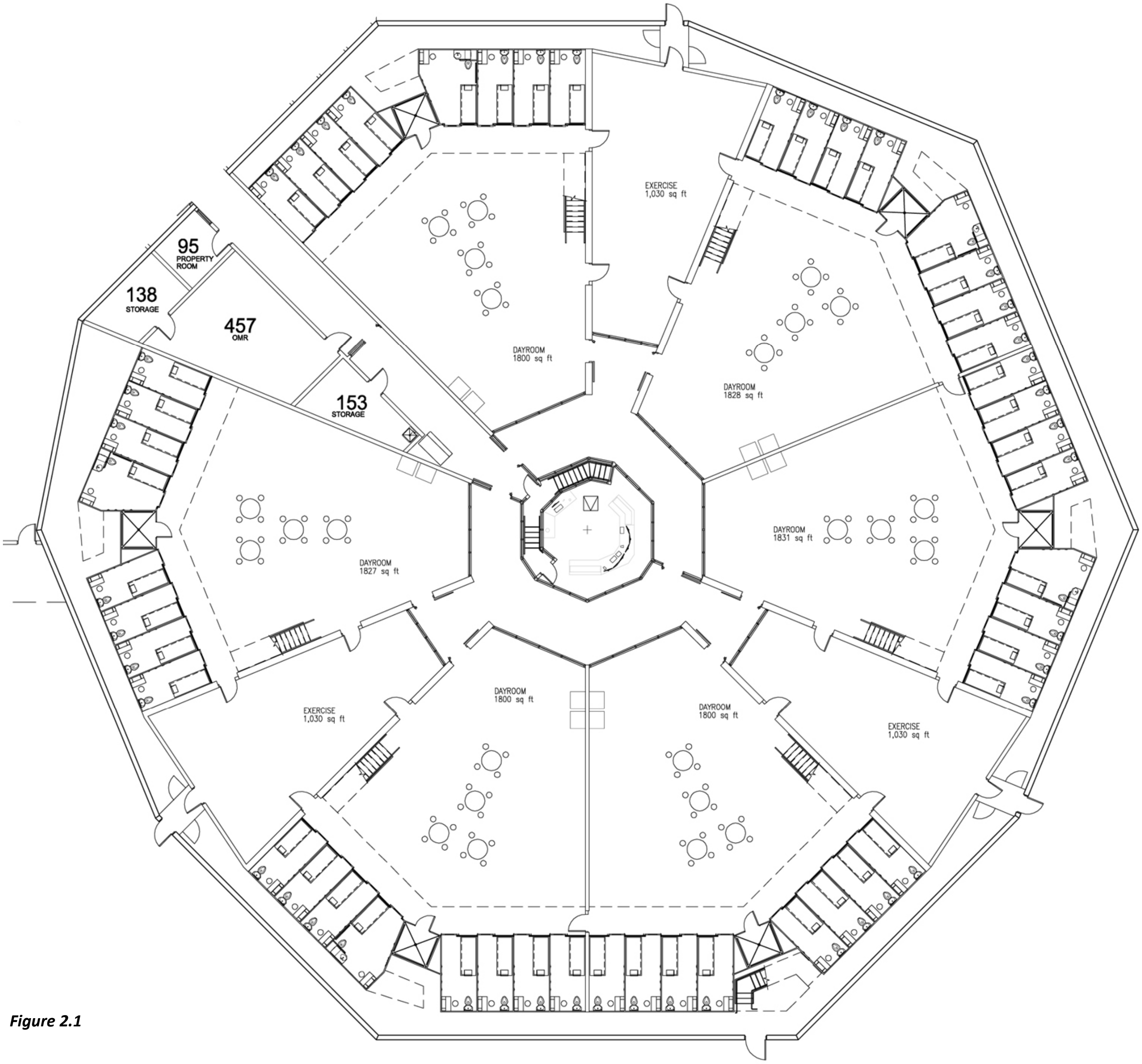


Figure 2.1

Table 2.1

Male:	% of Total	Housing Unit Type	Female:	% of Total	Housing Unit Type
Level 1	20%	Cell/192 Module	Level 1	5%	Cell/192 Module
Level 2			Level 2		
Level 3	40%	Cell/192 50% Dorm/288 50%	Level 3	95%	Dorm/288 Module
Level 4	20%	Dorm/288 Module	Level 4		
Level 5			Level 5		

The next step in the process was to aggregate the units into modules. Each prototypical housing module is comprised of 6 units of either cells or dorms. In general, it is not good practice to mix populations within a module, so we would not allow a module to contain four units of Level 1 & 2 inmates and two units of Level 3 inmates. Thus, the bed counts were adjusted again to reflect the module configurations. Note that there are specific instances where separate populations are allowed to share the same module, specifically Intake/Classification with Mental Health Observation.

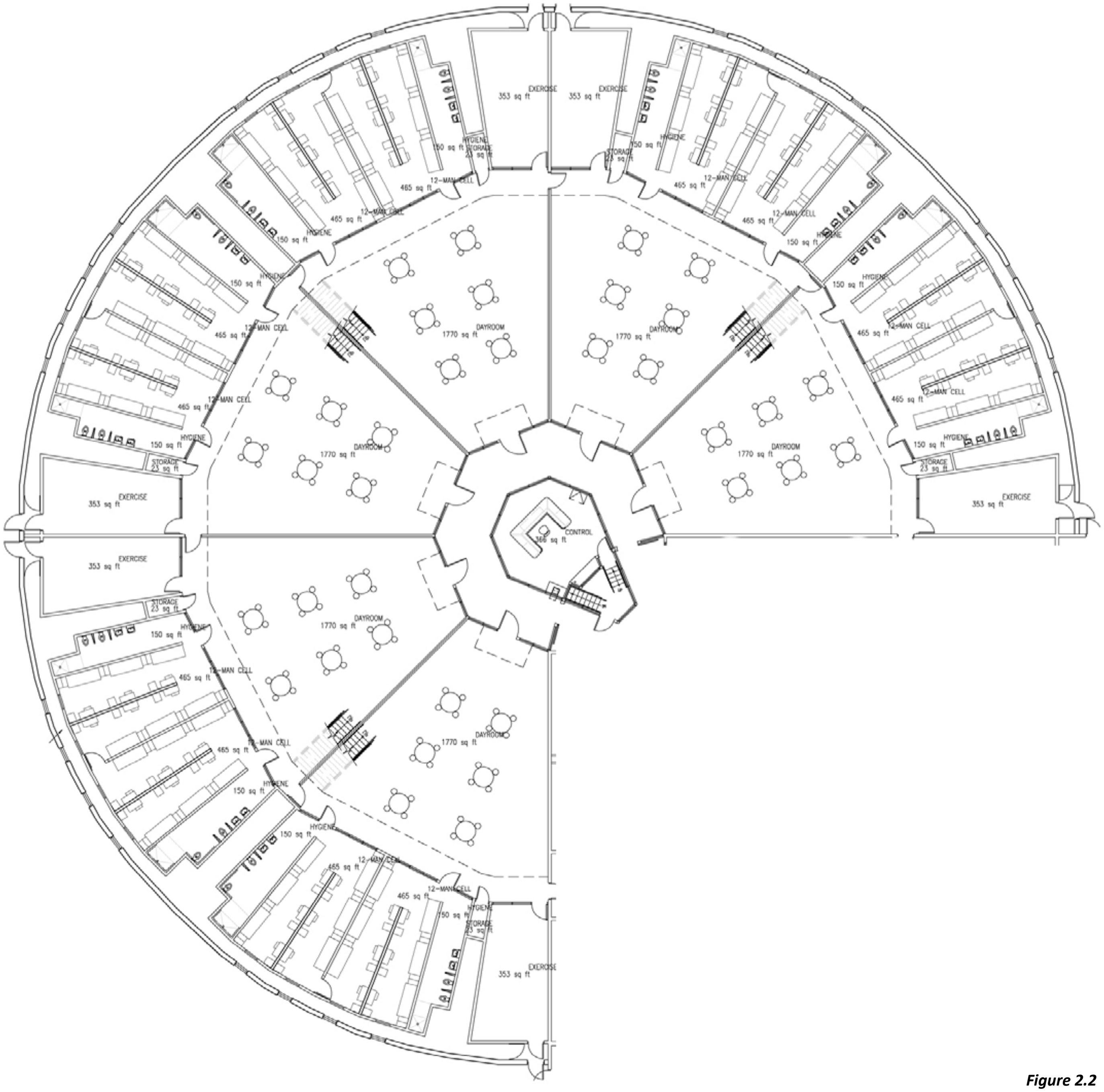


Figure 2.2

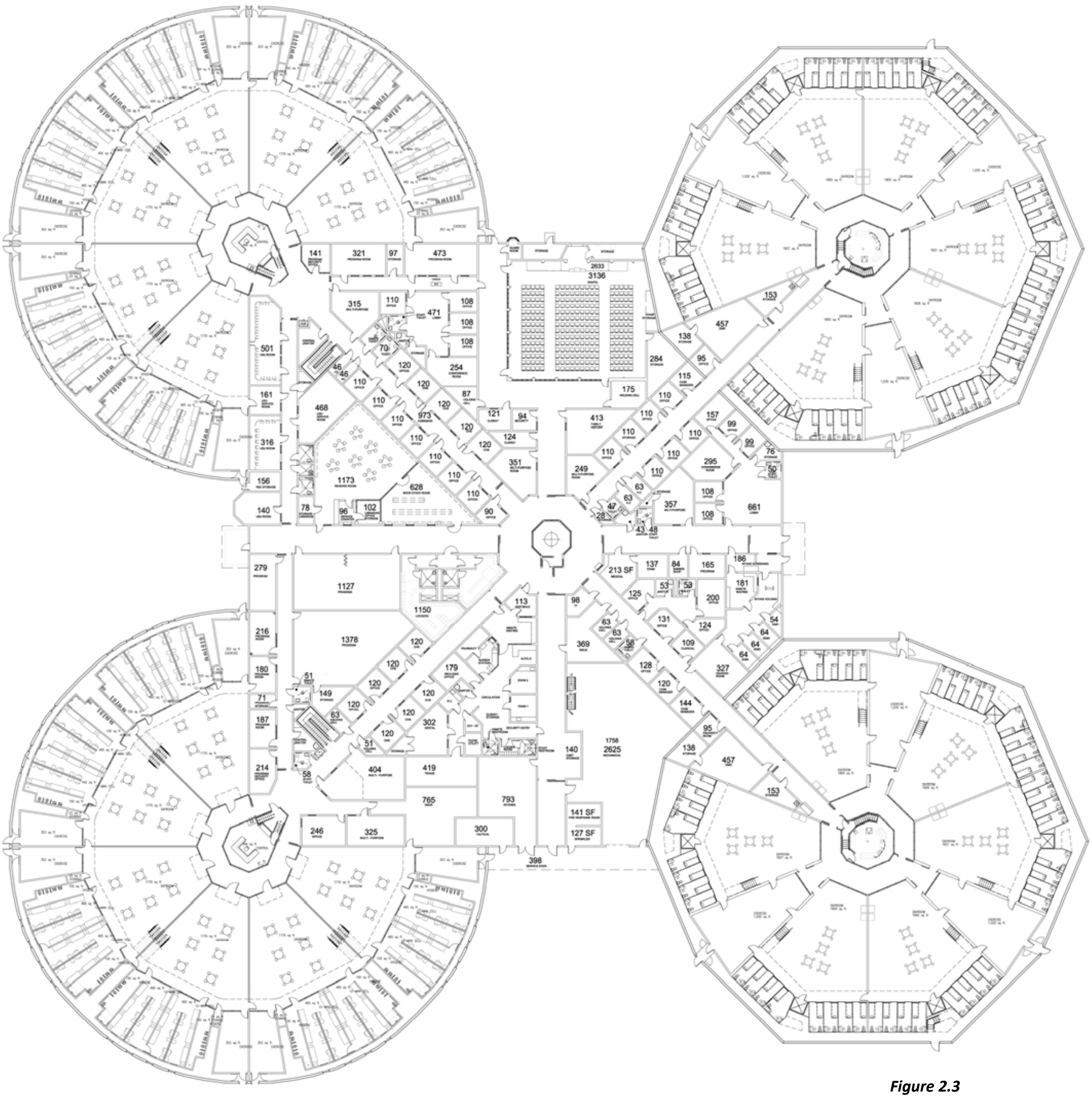


Figure 2.3

The next adjustment in the bed count came as the modules were formed into housing complexes. Each complex is comprised of four housing modules and an associated supporting core of functional spaces. As with the previous steps, sound, secure facility design practice dictates that, where possible, basic segregations not share a complex. Ideally, each management segregation forms its own prison within the larger prison complex and should be as self-contained as possible.

The study began with the assumption that at the conclusion of each phase, the project will be 100% built-out, meaning that each complex has four completed modules. This assumption leads to a final adjustment in bed counts to reflect a fully completed housing concept. So, what started as 5,000 male beds and 1,000 female beds at the conclusion of phase 1, became 5,424 male beds and 988 female beds reflecting all of the discussed adjustments. For phase 2 the bed counts are 7,776 and 1,668 as compared to 8,333 and

1,667 respectively. Graphical representation of each management segregation and the deployment of the required beds into units, modules and complexes is included in the Appendix X.

Lastly, note that the female population does not meet the 100% built-out expectation at the end of phase 2. An additional module to complete the phase 2 complex would have resulted in an excess bed count of almost 20% beyond the linear growth model. Because the phase 2 bed count requirement is so far in the future when management practices, population characteristics and statutory requirements may change significantly, it was decided to adhere to the growth model and ignore the “completeness” criteria.

NON-HOUSING FACILITIES

Non-housing facilities are based on serving the populations outlined previously. These facilities are divided as follows:

- Perimeter Control
- Miscellaneous Improvements
- Outside the Secure Perimeter
- Inside the Secure Perimeter

PERIMETER CONTROL

Functional Characteristics: Perimeter control facilities include a site traffic station to control access to the property, a vehicle sally-port to allow secure transfer of vehicles into and out of the secure perimeter and security towers at strategic points along the secure fence line. The planning of the security towers anticipates point to point visual control of the perimeter fencing system. In addition to these building elements, there are additional features of the perimeter control system that are described in the site development section of this report.

Construction Typology

Perimeter control facilities are designed to withstand the highest levels of potential attack because they occur at the interface point between the public and the secure environments. Bullet and blast resistant glazing, concrete, concrete masonry and steel are appropriate building materials for these facilities.

MISCELLANEOUS IMPROVEMENTS

Functional Characteristics: Miscellaneous improvements include the Sewage Treatment Facility and Culinary Water Facility to provide those services to the remote site. Also included are staff and visitor parking lots, and kennels and training area for the working dogs. Visitor parking has been reduced based on the anticipated usage of video visitation systems. Contact visitation normally generates the highest volume of public traffic.

Construction Typology

Miscellaneous improvements are designed to meet the utilitarian functions contained within those facilities. Industrial building types are appropriate for these facilities.

OUTSIDE SECURE PERIMETER

Functional Characteristics: Facilities included outside of the secure perimeter are those that do not require, or would be negatively impacted by direct inmate access. These include the administration facilities, the enforcement center, vehicle pool facilities, a central plant and warehousing. It is anticipated that the male and female facilities would, to some extent, have their own administrative facilities, but that the balance of the facilities in this category would be shared by the two prisons.

Construction Typology

Buildings constructed outside the secure perimeter may be designed of materials suitable for that building type in a non-justice facility.

INSIDE SECURE PERIMETER

Functional Characteristics

Facilities included within the secure perimeter are those that service direct inmate needs or are accessed by inmates on a regular basis. Inmate services include contact visitation, court facilities, education, religious worship and education, central library facilities, mental health, medical care and industry programs. Also included are the central laundry, culinary, and refuse management facilities. Lastly, inmate reception and orientation facilities are included in this group. With the exception of the culinary program, all of these facilities are required in both prison campuses. UDOC anticipates utilizing a single cook-chill plant, shown as a part of the men's prison, to produce the food for both populations.

Construction Typology

Buildings constructed inside the secure perimeter, with the exception of housing facilities, may be designed of materials suitable for that building type in a non-justice facility. Housing facilities are constructed of durable, abuse and attack resistant materials suitable to the inmate type housed. Housing facilities are designed to keep the inmates securely confined. The UDOC secure facility standards describe appropriate materials.

CONCEPT PROGRAM

The previous discussions are summarized in a concept development program, included as in Appendix X. The program document lists all of the major functions required for a prison. Gross square footage has been assigned to each of the functions, and then appropriate functions are grouped together to describe required buildings. In addition to the building areas, developed site area requirements are also summarized in the program document.

The characteristics of the programmed facility are:

- Phase 1
  Male Facility
  Beds – 5,424
  Programmed Gross Square Feet – 1,790,625
  (includes shared facilities)

- Female Facility
  Beds – 988
  Programmed Gross Square Feet – 286,496

- Phase 2
  Male Facility
  Beds – 7,776
  Programmed Additional Gross Square Feet – 644,600

- Female Facility
  Beds – 1,668
  Programmed Additional Gross Square Feet – 173,567

SITE DEVELOPMENT

Based on the concept program, building masses have been developed and arranged on the preferred site. The arrangement of the buildings is based on the model developed in Gunnison, with the Administration Building serving as the gateway into the secure facility for pedestrian traffic. The Administration Building is connected via a corridor or tunnel to the secure portion of the facility. Housing complexes are arranged into segregation zones that isolate each inmate type from the others. Some functions, culinary, for example, are located in proximity to the inmate population that will staff them.

A non-secure fence line will define the full extent of the prison property, including utility plants, agricultural activities and treatment facilities. The secure areas of the prison are contained within a double fence-line with 25 feet between the two lines. The characteristics of the secure fence are described in the UDOC Secure Facility Standards. The secure fence must be located a minimum of 300 feet from a public road, and 250 feet from the non-secure fence line. Housing units are then located no closer than 150 feet from the inside line of the security fence system.

Drawings of the anticipated improvements are included on the following pages. These drawings illustrate the following:

Master Site Plan, illustrating the intended usages of the entire available parcel at the conclusion of phase 2.

Phase 1 Site Plan, illustrating the end-state improvements of the phase 1 program supporting 6,412 beds specifically in the area of prison development.

Phase 1 aerial views:

- Men's Facility – view looking to the northeast.
- Men's Facility – view looking to the southwest.
- Women's Facility – view looking to the northeast.
- Women's Facility – view looking to the southwest.

Phase 2 Site Plan, illustrating the end-state improvements of the phase 2 program supporting 9,444 beds specifically in the area of prison development.

Phase 2 aerial views:

- Men’s Facility – view looking to the northeast.
- Men’s Facility – view looking to the southwest.
- Women’s Facility – view looking to the northeast.
- Women’s Facility – view looking to the southwest.

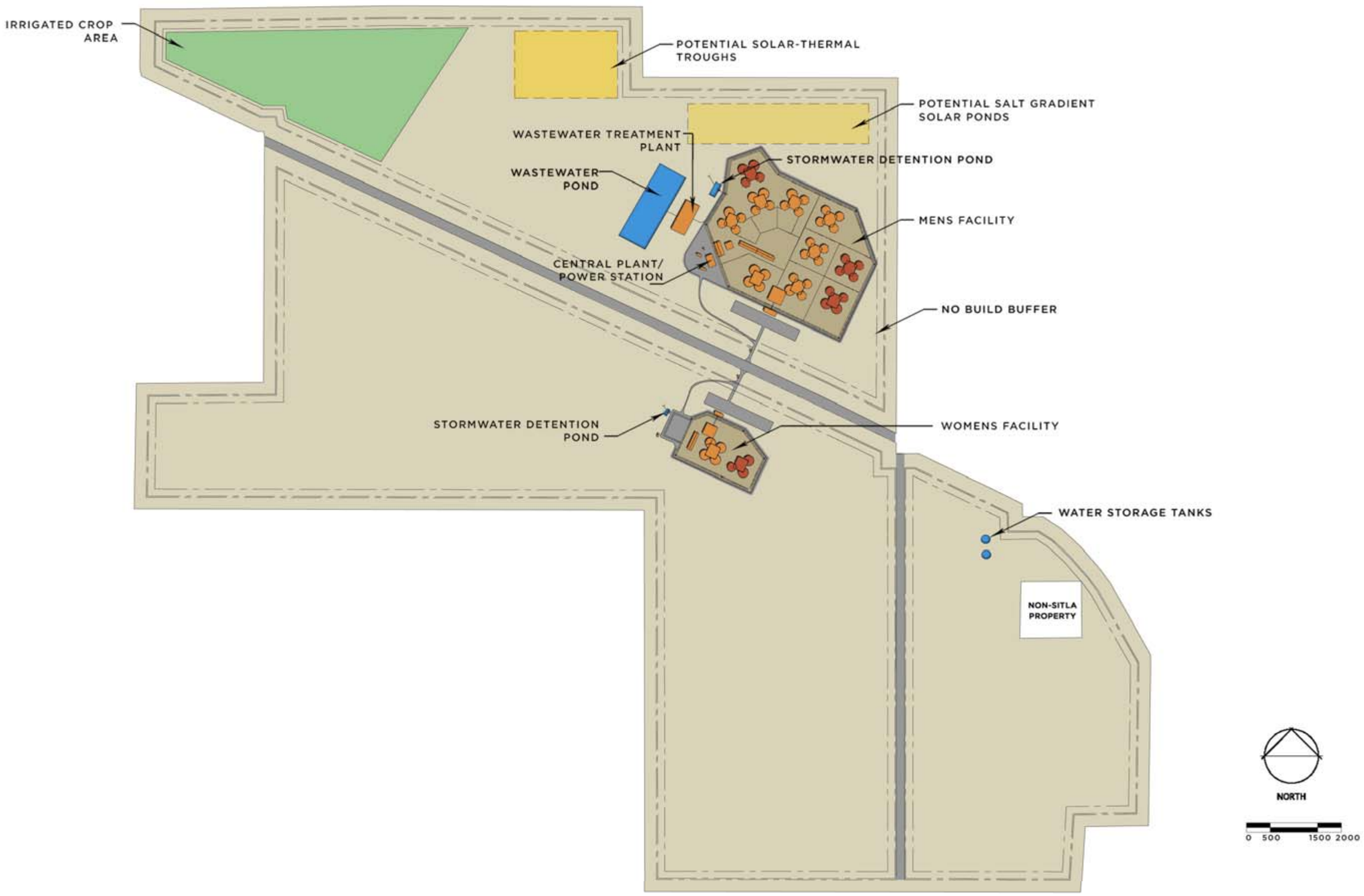


Figure 2.4: *Master Site Plan*

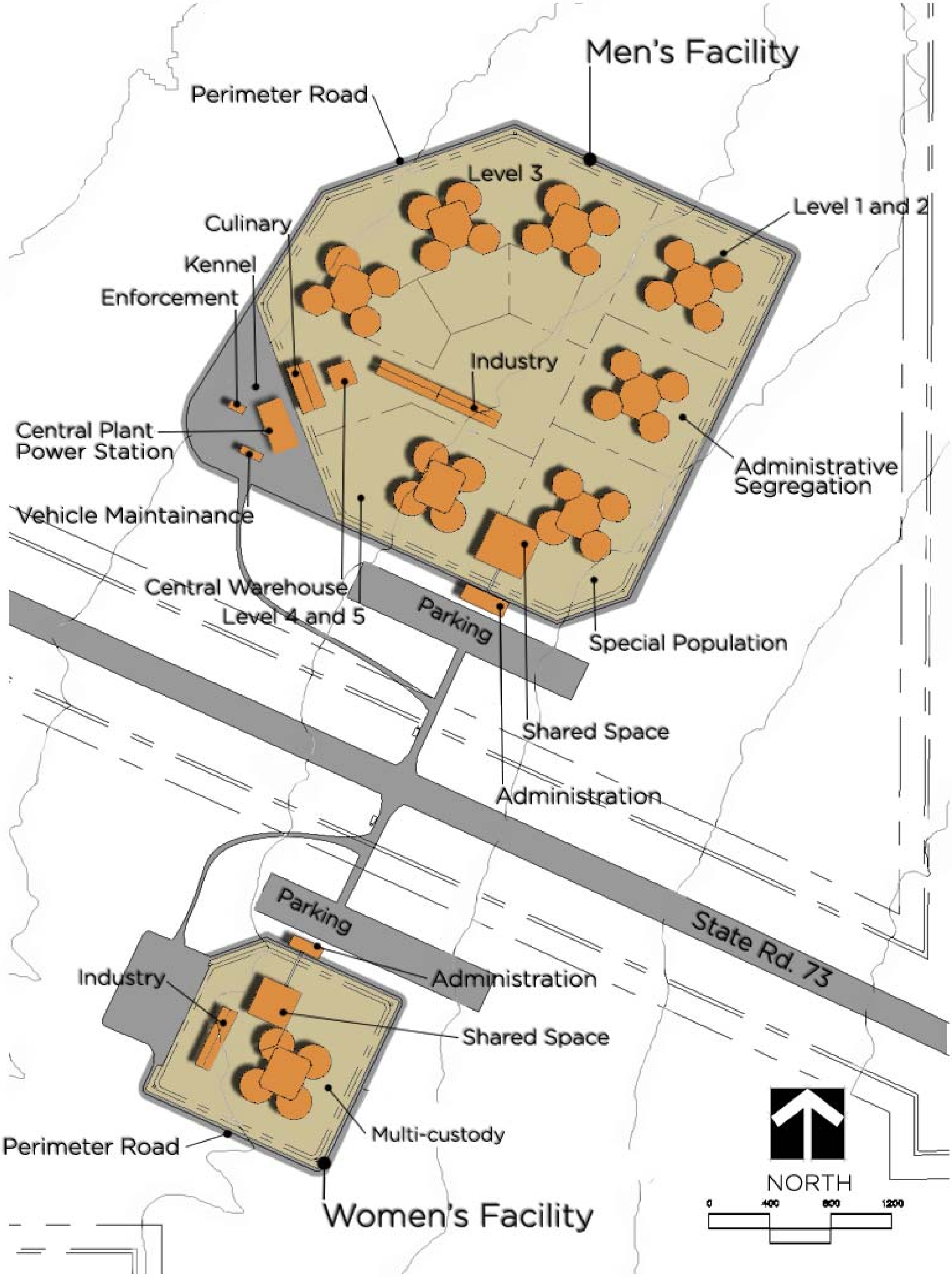


Figure 2.5: *Phase 1 Site Plan*

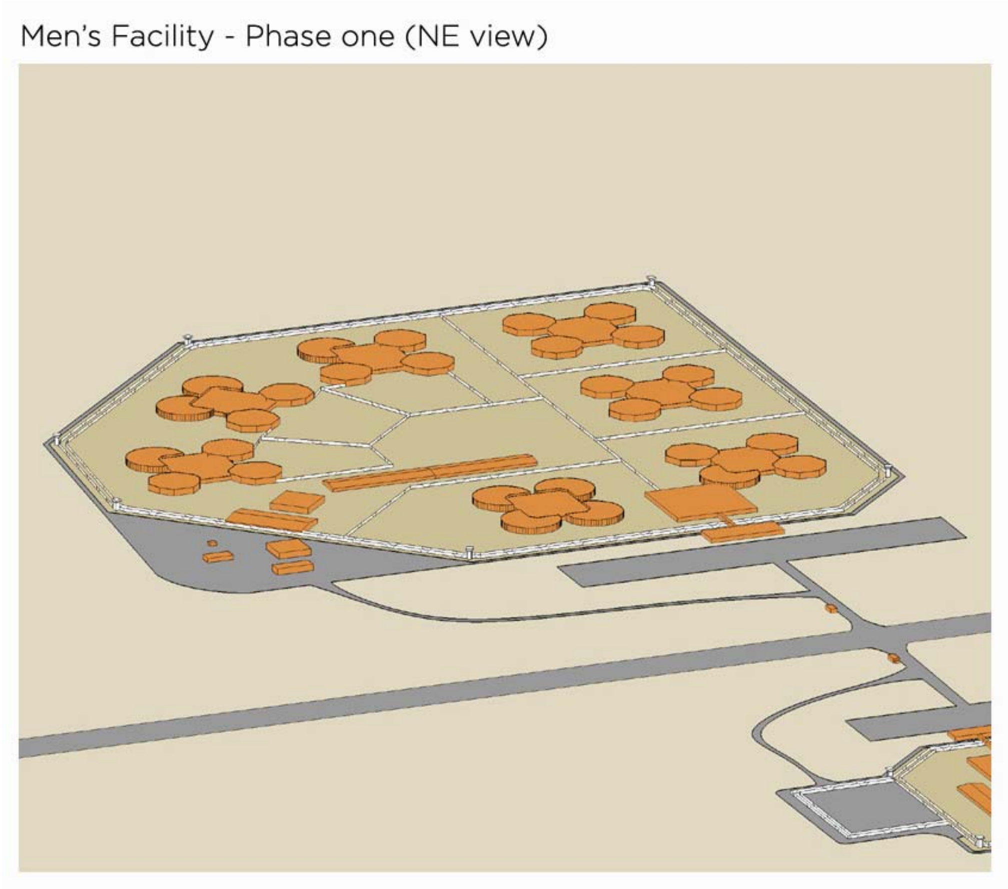


Figure 2.6: *Men's Facility Phase 1 NE View*

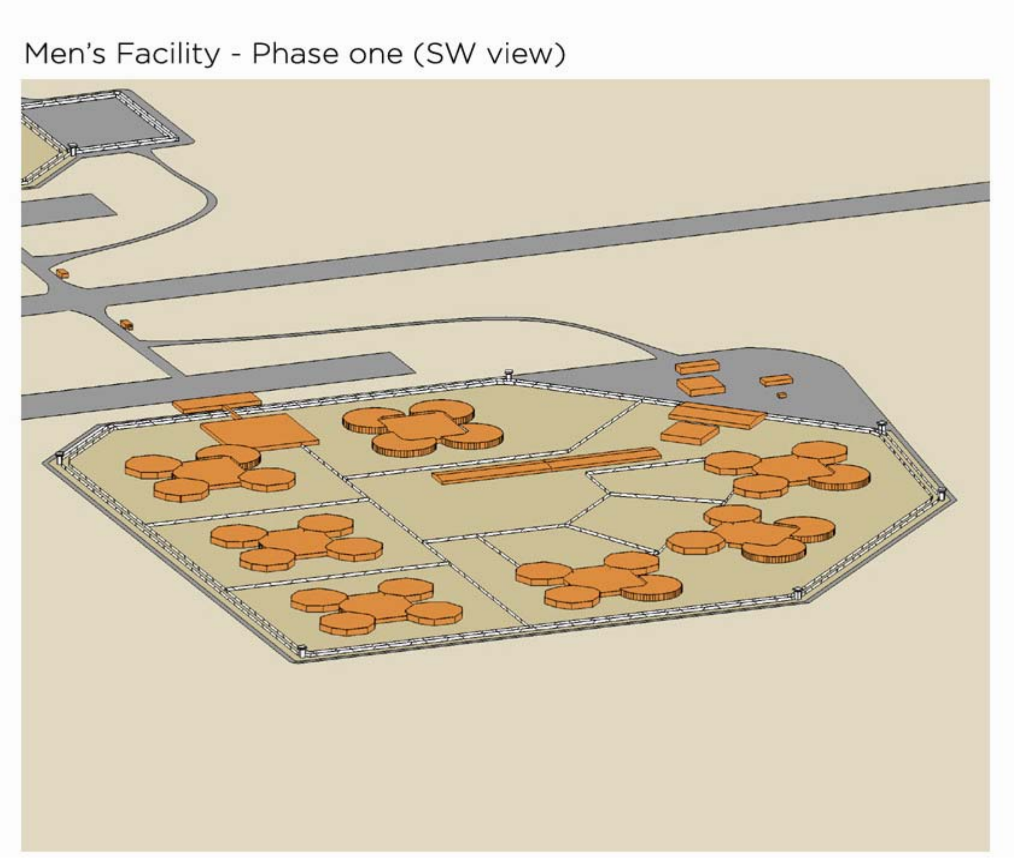


Figure 2.7: *Men's Facility Phase 1 SW View*

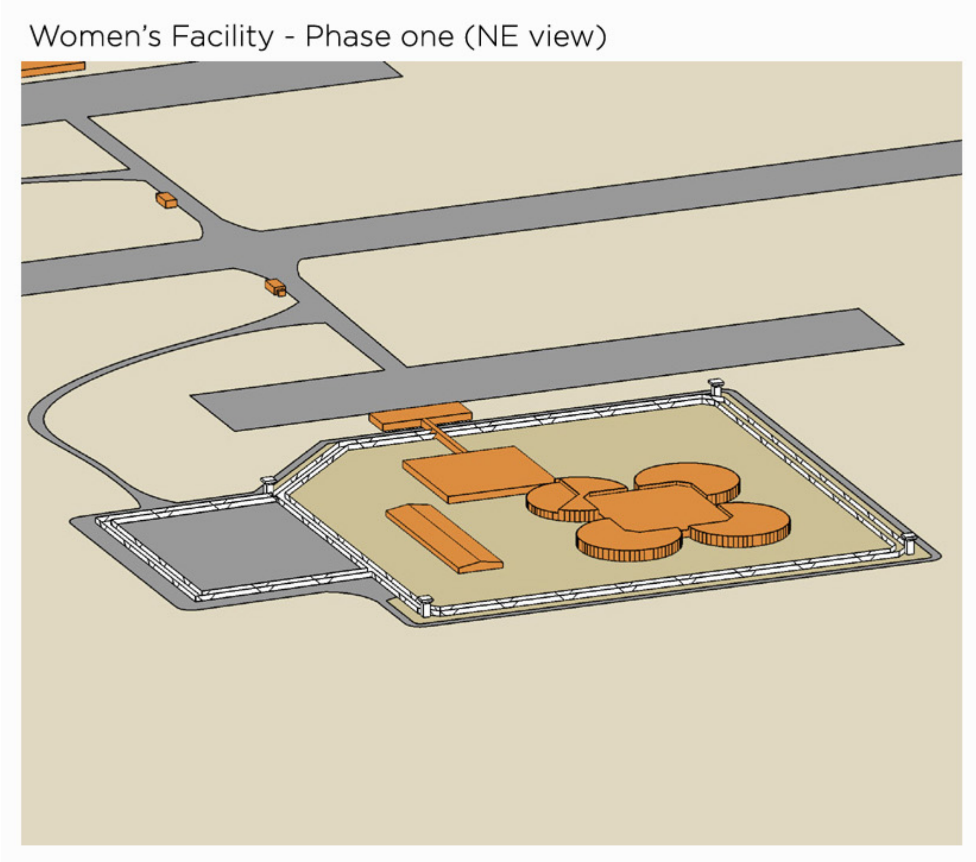


Figure 2.8: *Women’s Facility Phase 1 NE view*

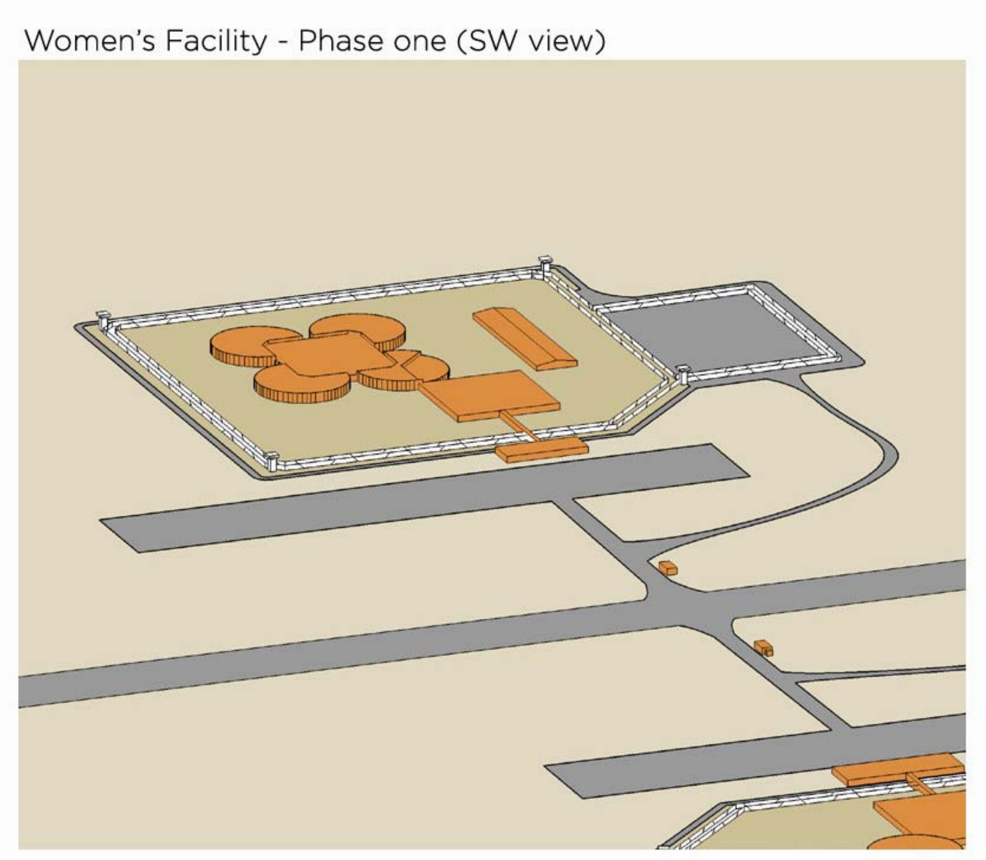


Figure 2.9: *Women’s Facility Phase 1 SW view*

Figure 2.10 *Phase 2 Site Plan*

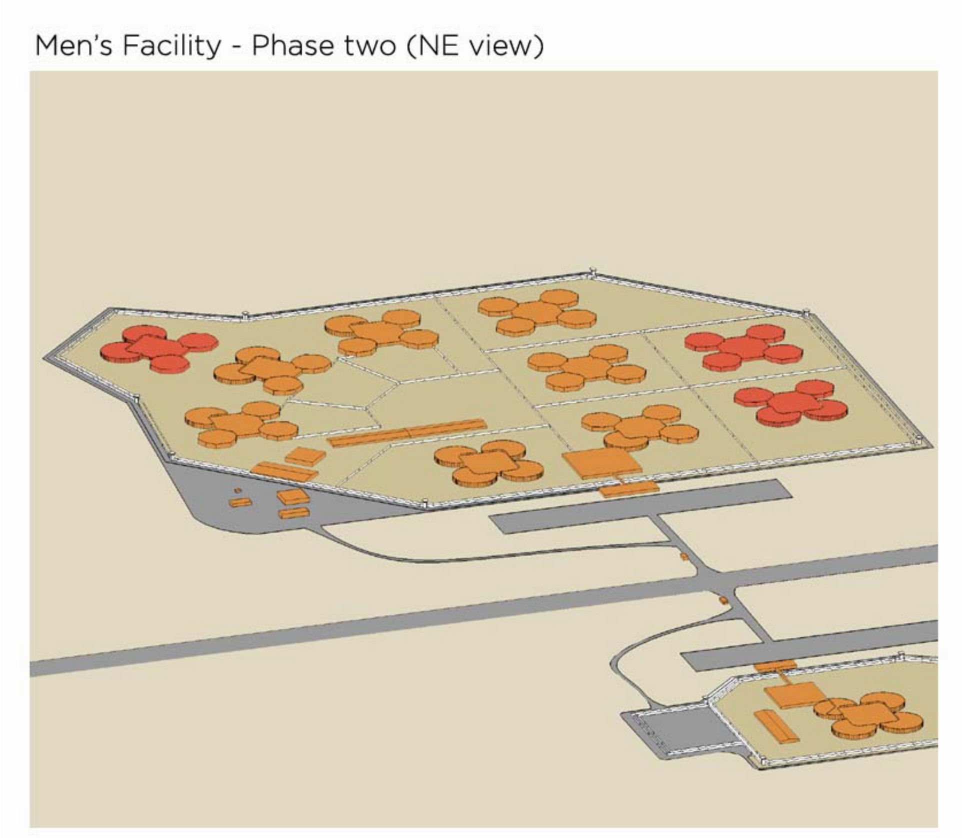


Figure 2.11: *Men's Facility Phase 2 NE View*

Figure 2.12: *Men's Facility Phase 2 SW View*

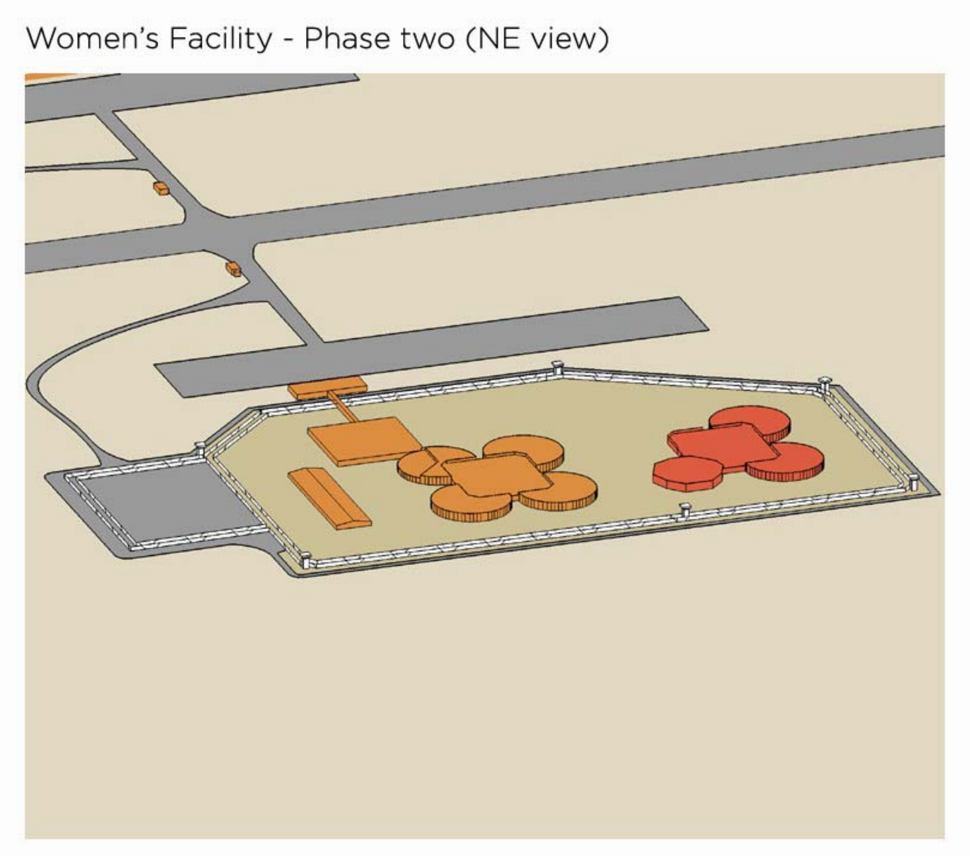


Figure 2.13: *Women's Facility Phase 2 NE View*

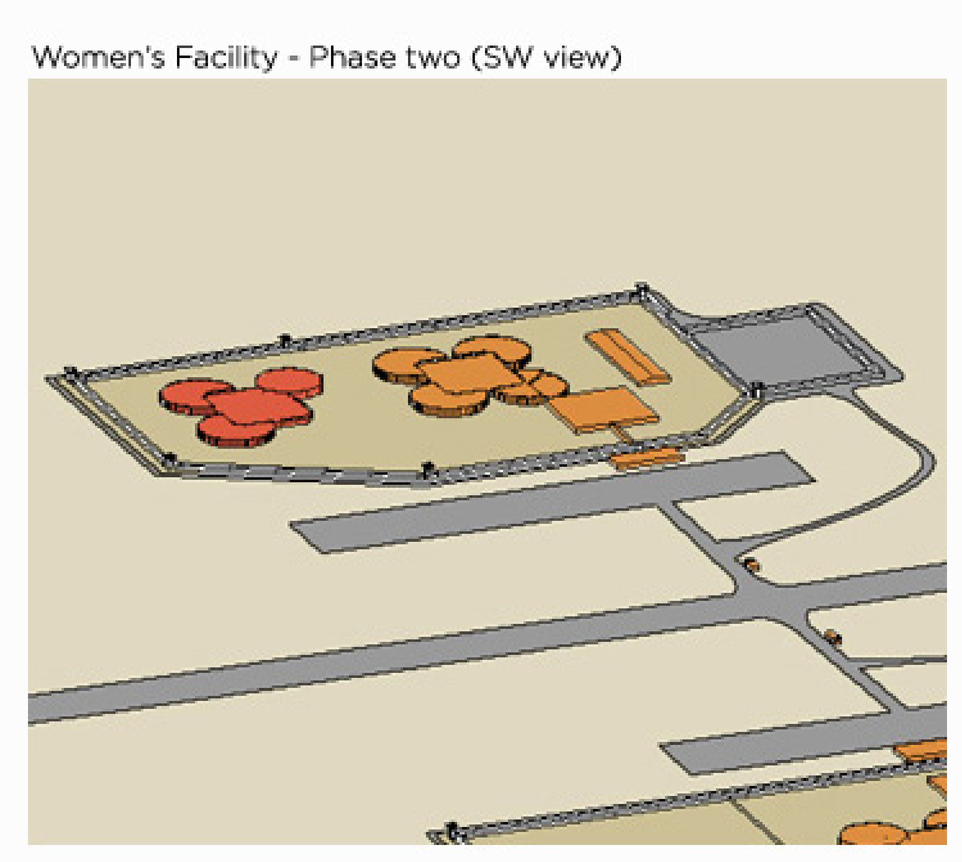


Figure 2.14: *Women's Facility Phase 2 SW View*

SECTION III: WATER AND WASTEWATER INFRASTRUCTURE ANALYSIS

The proposed prison site location has been studied to determine potential fatal flaws in providing the required water, wastewater, gas supply, and storm drainage infrastructure. The analysis approximated the requirements for a 6,000 bed facility and a 10,000 bed facility. The study included an investigation of culinary water sources, sanitary sewer, wastewater treatment, natural gas supply, storm drainage, facility placement, and geologic conditions. This study is a fatal flaw analysis as well as a budgeting analysis. It should be used for planning purposes only. See Figure 3.1 for a site map of the major water infrastructure.

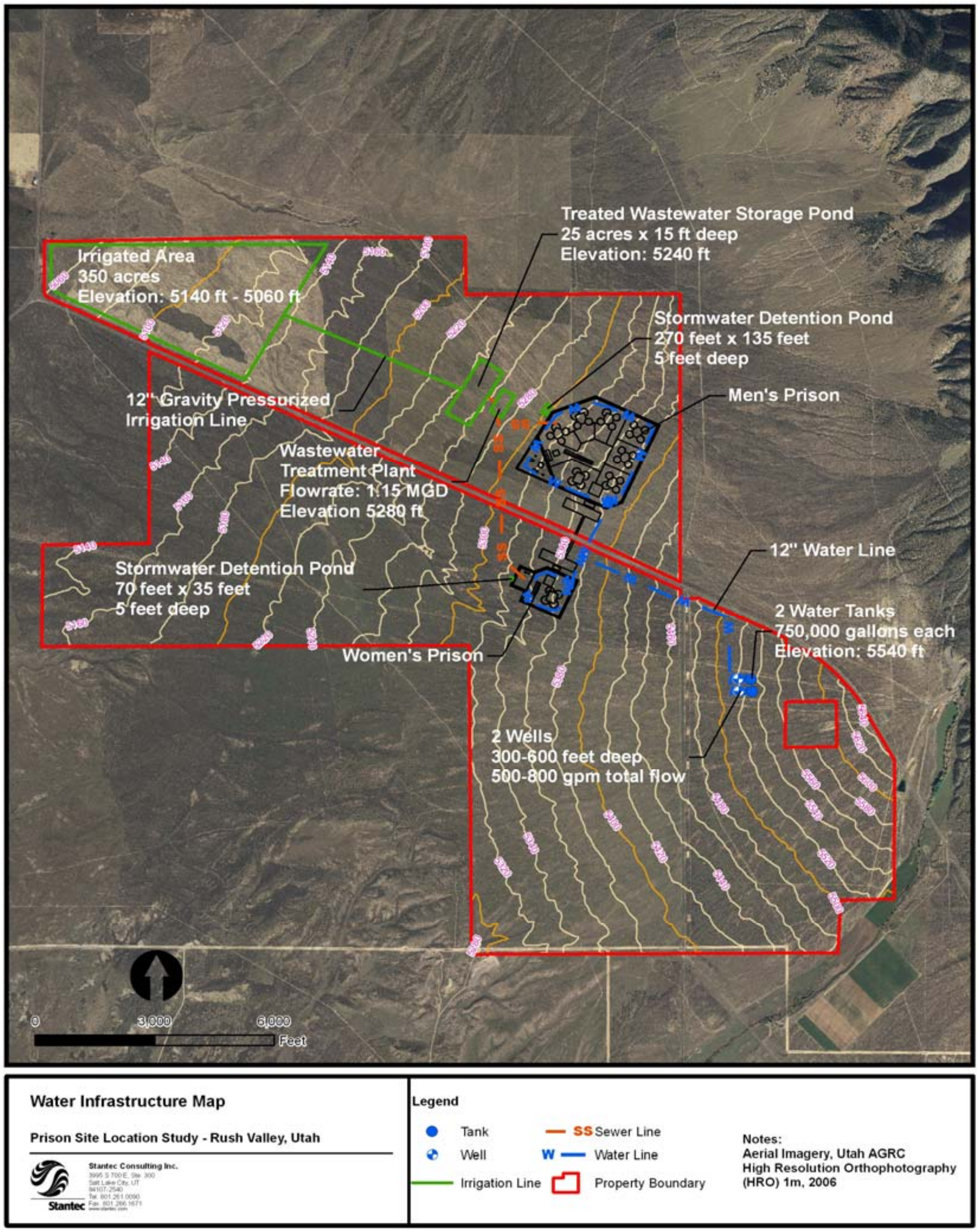


Figure 3.1: *Water Infrastructure Map*

CULINARY WATER ANALYSIS

The culinary water analysis included an investigation of water supply and infrastructure requirements. The study included a water demands analysis , a preliminary investigation of the availability of water rights appropriations, a preliminary groundwater quality analysis, a preliminary water rights analysis, a preliminary hydrogeologic review of potential groundwater sources, and an engineering analysis of major water distribution infrastructure requirements. A preliminary hydrogeologic analysis was conducted to determine the feasibility of drilling wells adequate to supply the site.

WATER DEMANDS ANALYSIS

Data from the existing Draper facility was used to determine the water demands for the future prison site. Demands at the Draper site were reported by the Department of Corrections to be:

- 115 gallons per prisoner bed per day.

This demand was used to estimate a total demand for a 6,000 bed facility to be:

- 0.7 MGD (million gallons per day), this is equivalent to approximately: 400 gpm (gallons per minute)

Total demand for a 10,000 bed facility would be:

- 1.15 MGD, this is equivalent to approximately: 800 gpm.

This flow rate was used to establish the required flow rate from the source wells.

A peaking factor of 2x was used to determine the peak day demand and as well as an assumed fire flow of 1,500 gpm.

- The peak flow rate for the 6,000 bed facility is 2,300 gpm.
- The peak flow rate for the 10,000 bed facility is 3,100 gpm.

The fire flow of 1,500 gpm was assumed, further investigation into this value will be required.

PRELIMINARY GROUNDWATER QUALITY ANALYSIS

A preliminary groundwater quality analysis was conducted for the parcel in the Rush Valley area. The data that were utilized include:

- Technical publications by the Utah Division of Water Rights (UDWR), including Technical Publication No. 23 and Technical Publication No.18;
- UDWR database search for existing points of diversion; and
- Data obtained from studies by Stantec Consulting Inc.

It is important to note that the water quality data obtained from the published reports are from the late 1960's and water quality in the region may have changed since these data were published. No attempts were made to obtain water quality records for public supply wells in the region from the Utah Division of Drinking Water (UDDW) through the Government Records Access and Management Act (GRAMA) process.

For the purposes of this investigation, the primary water quality parameter that was investigated is Total Dissolved Solids (TDS). The primary standard set forth by the UDDW for TDS is 1,000 milligrams per liter (mg/l) unless the supplier can satisfactorily demonstrate that no better water is available. The secondary standard for TDS is 500 mg/l, which means that levels in excess of this value will likely cause consumer complaint.

In the vicinity of the proposed prison parcel, the concentration of total dissolved solids (TDS) ranges from 350 to 2,180 ppm [Technical Publication 23]. See Figure 3.2 for a diagram of the distribution of dissolved solids in ground and surface waters from Technical Publication 23 [Technical Publication 23]. Most of the water in Rush Valley contains more than 181 ppm of hardness as calcium carbonate and is classed as very hard by the United States Geological Survey. Edges of the Ophir Canyon fan, near these parcels, may yield large quantities of groundwater to wells, but it is unknown how much.

PRELIMINARY WATER RIGHTS ANALYSIS

Rush Valley is restricted for new appropriations to small water rights appropriations only. No new appropriations are greater than 4.73 acre-feet per year. See Figure 3.3 for a map of groundwater appropriations policy. Water usage for the prison site was estimated to be between 770 and 1,290 ac-ft per year. This volume of water rights could not be obtained from new appropriations, but would need to either be purchased or transferred from another basin. The Utah Department of Corrections (UDC) owns water rights shares in the Salt Lake Valley. The UDC could potentially transfer rights from this basin to the Rush Valley Basin; however, moving water rights from one basin to another basin is very difficult. It is beyond the scope of this analysis to determine the feasibility of transferring existing water rights from another basin to Rush Valley. Stantec recommends that a water rights attorney be consulted in order to assess the feasibility of moving rights from another basin to this piece of property.

If water rights are purchased, the cost would be between $10,000 and $15,000 per acre-foot according to research done by Wikstrom and Stantec. The cost of water rights for a 6,000 bed facility would be approximately $9.6 million assuming an average of $12,500 per share.

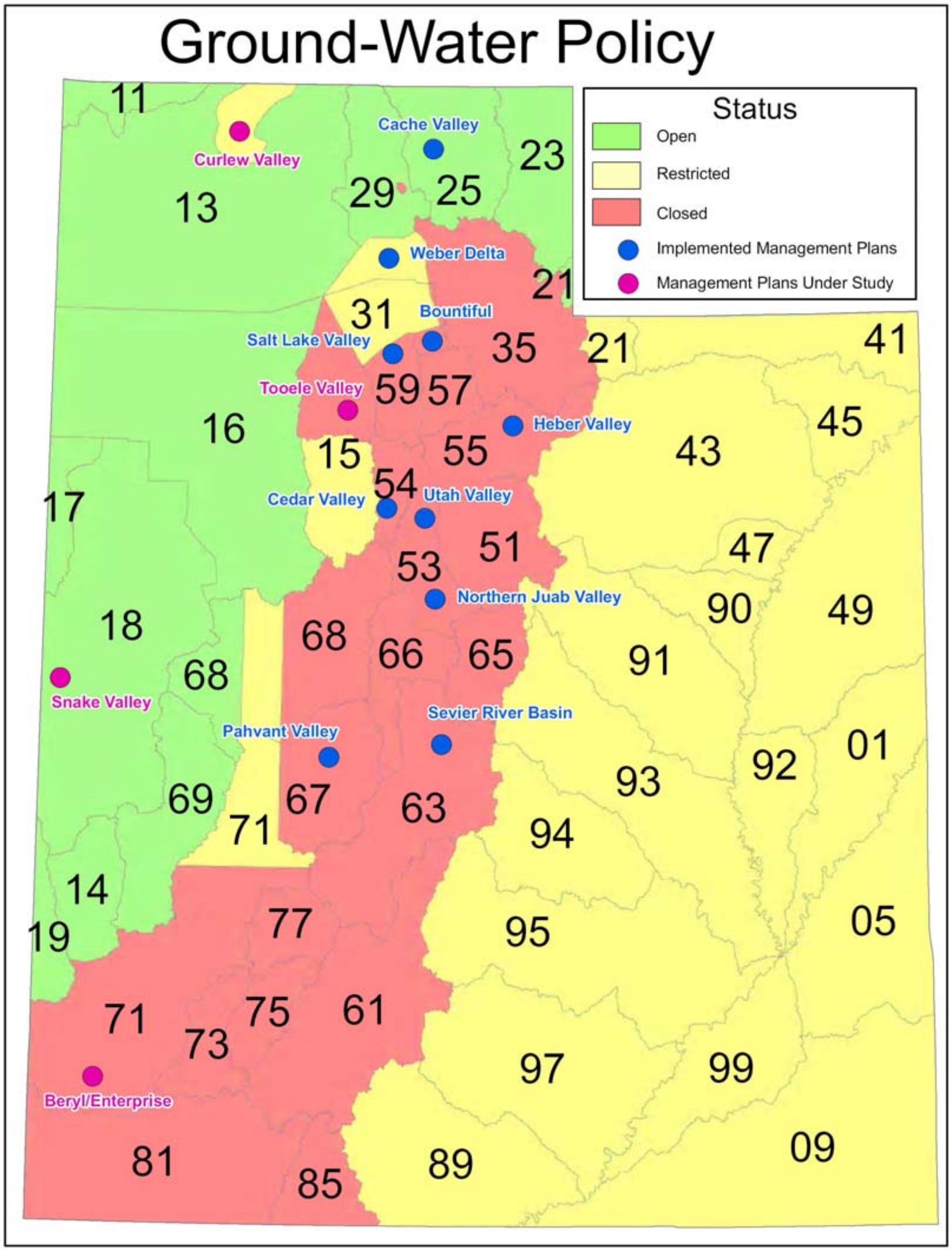


Figure 3.2: *Groundwater Water Rights Appropriations Map*

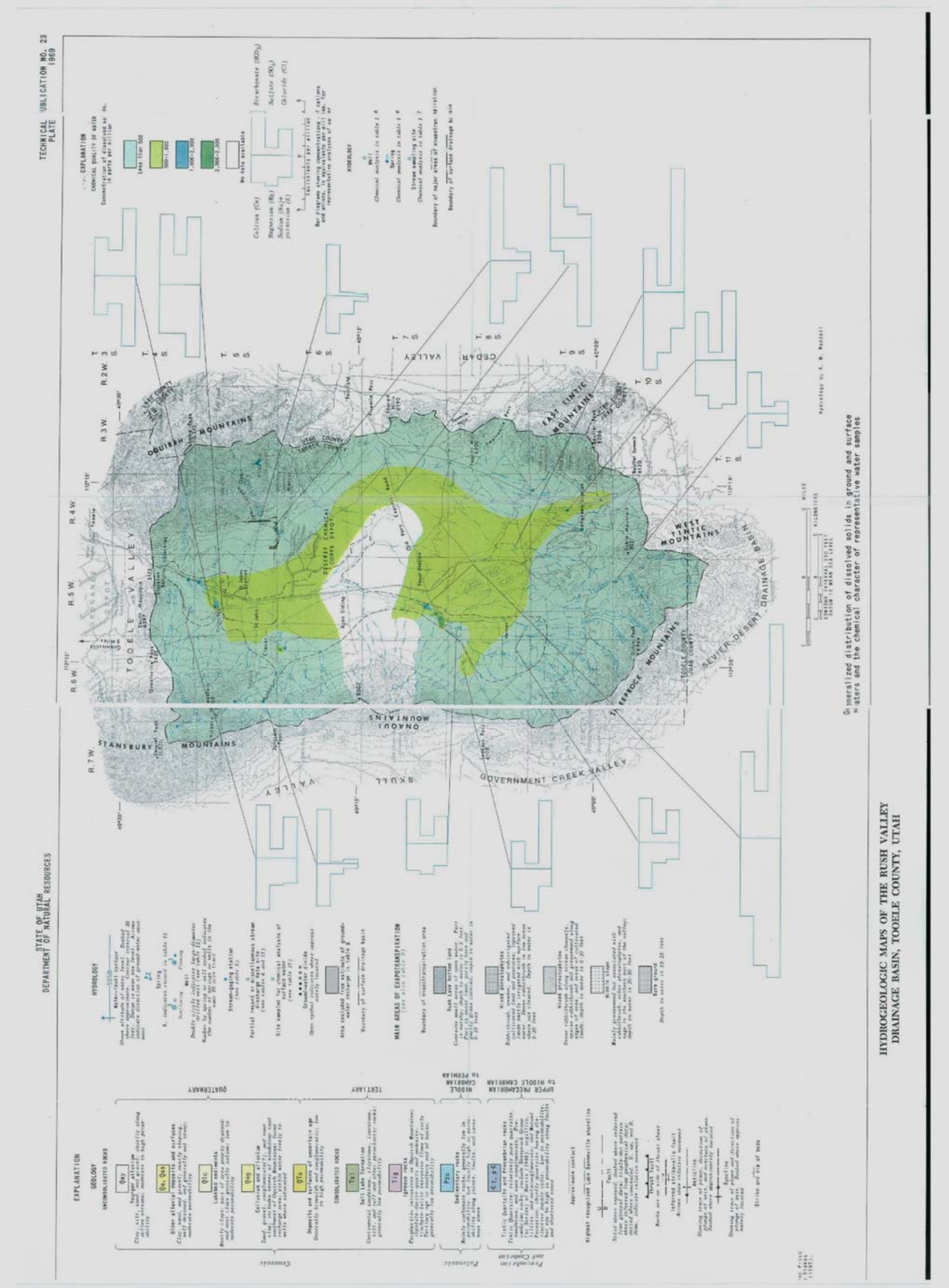


Figure 3.3: *Distribution of Total Suspended Solids in Groundwater in Rush Valley*

PRELIMINARY HYDROGEOLOGIC ANALYSIS

The preliminary hydrogeologic review studied the areas surrounding the proposed prison site including the areas located several miles south of the town of Stockton and directly east of the town of Rush Valley. The purpose of the review was to examine the production capabilities of groundwater sources in the vicinity of the proposed prison site with respect to meeting the future water demand of 500 – 800 gallons per minute (gpm). The preliminary hydrogeologic analysis used the following sources of information:

- Existing published geologic and hydrogeologic information for the region.
- Technical Publications authored by the Utah Department of Natural Resources Division of Water Rights and the U.S. Geologic Survey.
- Well Logs from existing wells
  - 1 meter aerial photographs from the National Agricultural Imagery Program (NAIP) from 2006.

PHYSIOGRAPHIC AND HYDROGEOLOGIC SETTING

Rush Valley covers approximately 250,000 acres and is a closed basin typical of the Basin and Range Physiographic Province [Technical Publication 18]. The mountains that surround Rush Valley are folded and faulted sedimentary, metamorphic and igneous rocks. These include the Oquirrh and East Tintic Mountains on the East, the Stansbury and Onaqui chains on the west and the Sheeprock and West Tintic Mountains to the south.

Consolidated rocks form the mountains surrounding Rush Valley. The consolidated rocks can be divided as follows:

1 Metasedimentary rocks of Precambrian Age and the Tintic Quartzite of Cambrian Age. The Precambrian rocks and Tintic Quartzite crop out only in the Sheeprock Mountains and the quantity of water stored is small.

2 Paleozoic sedimentary rocks which are mainly carbonates. The Paleozoic sedimentary rocks are exposed in the mountains and underlie younger rocks in parts of Rush Valley. Some formations of Paleozoic age yield large quantities of water including the Manning Canyon Shale and the Oquirrh Formation. The Oquirrh Formation yields large quantities to two wells owned by Tooele City drilled north of Vernon, with rates estimated at 4,100 gpm and 8,600 gpm, respectively. These two wells were drilled on the trace of a covered fault and another well drilled west of the fault trace yielded much less. Therefore large well yields appear to depend on localized favorable conditions. These wells are approximately 14 miles south of Parcels 2 and 3.

3 Tertiary igneous rocks, and the Salt Lake Formation of Pliocene age. Both the Tertiary igneous rocks and the Salt Lake Formation have low permeability and do not have much potential to yield water.

Although groundwater may be locally available from bedrock formations, the main groundwater reservoir in Rush Valley is in the unconsolidated rocks of late Tertiary and Quaternary age. The source of all water in Rush Valley is precipitation that falls on the mountains. The normal annual precipitation in Rush valley is less than 10 inches in the lowlands to more than 40 inches in the Oquirrh and Stansbury Mountains. In the vicinity of the Prison Parcels, the unconsolidated rocks consist of 20-100 feet of coarse-grained deposits that rest on a thick section of pre-Lake Bonneville lacustrine clay. The majority of wells surrounding Parcels 2 and 3 yield less than 50 gpm except those that will be discussed in more detail in the following section.

Existing Wells

Based on a Utah Division of Water Rights (UDWR) database search around the proposed prison site, although most nearby wells yield less than 100 gpm, several wells were found that yield quantities of water in excess of 100 gpm. These wells are illustrated in Figure 3.4 and details about each well follow.

1 Sep-Stockton LLC Wells (WR 15-2972)

The Sep-Stockton Wells include several existing and abandoned wells. The first well drilled in 1987 flowed artesian and was capable of 1,350 gpm with 60 feet of drawdown. This well was drilled to a depth of 340 feet and was later abandoned. A second well was drilled in 1990 to a depth of 315 feet and was capable of 1,000 gpm with 90 feet of drawdown. This well was also later abandoned. A third well was drilled in 2000 to a depth of 425 feet and flowed artesian at a rate of approximately 12 gpm. This well was never developed or tested, and was later abandoned. A fourth well was drilled in 2005 to a depth of 900 feet. According to the Well Driller's Report (Appendix X), this well encountered quartzite bedrock at an approximate depth of 517 feet. This well was later pumped at a rate of 2,250 gpm with 271 feet of drawdown.

2 USA Department of the Army – Tooele Army Depot (WR 15-73)

The United States Army has two wells at the Deseret Chemical Depot. Both wells were drilled in 1942 to depths of 404 feet and 428 feet, respectively. Both were completed in gravels and are capable of approximately 370 gpm with 5 to 10 feet of drawdown (see Well Driller's Report in Appendix X).

3 Hogan Brothers Inc (WR 15-136 and 15-137)

The Hogan Brothers Wells include three well sources. Two have no information on production potential while a third that was drilled in 1973 to a depth of 209 feet is capable of 1,140 gpm with 77 feet of drawdown. According to the Well Drillers Report (Appendix X) this well was completed in unconsolidated sands and gravels.

4 Georgia Monroe – formerly Snyder Mines Inc (WR 15-2330)

Two wells formerly owned by Snyder Mines Inc were drilled in 1937 to depths of 86 feet and 90 feet, respectively (see Well Driller's report in Appendix X). The first is capable of 146 gpm with 15.5 feet of drawdown. The second is capable of 178 gpm with 15.5 feet of drawdown.

5 Joe Sandino (WR 15-163)

This well was completed to a depth of 300 feet in 1963 and flowed artesian. Based on the Well Driller's Report (Appendix X), the well was estimated to flow 650 gpm in 1963 when it was drilled. The well appears to be completed in unconsolidated sands and gravels.

HYDROGEOLOGIC SUMMARY AND RECOMMENDATIONS

Based on a review of the Utah Division of Water Rights database there are several wells in the vicinity of the proposed prison site that are capable of discharge rates greater than 100 gpm and as great as 2,250 gpm. The well that yielded 2,250 gpm was drilled to a depth of 900 feet and encountered bedrock conditions. All other wells investigated target unconsolidated sands and gravels.

Based on the information provided in this hydrogeologic review, it may be possible to drill several wells in the unconsolidated sands and gravels on the proposed prison site that could supply the required demand of 500 – 800 gpm. It is unclear if the required demand could be supplied by only one well. It is likely that more than one well would need to be drilled to supply the required demand. It also may be possible to target a bedrock aquifer(s), but a more detailed well siting study would be required. Regardless of the target formation, if wells are drilled in the area a test well program is recommended. A test well program would provide the additional data needed to further evaluate the groundwater resource.

WATER SUPPLY INFRASTRUCTURE ANALYSIS

The water supply infrastructure analysis developed approximate sizes of the major infrastructure components only. The main water supply infrastructure components includes: the multiple well system, well pumps, water storage tanks, the main water distribution lines, and the water distribution loops. This infrastructure analysis was conceptual and does not include minor equipment such as control valves, altitude valves or pressure reducing valves.

The water supply conceptual analysis assumed that the required groundwater supply was available from the multiple well system. The conceptual water supply infrastructure includes:

- 2(or more) wells approximately 300-600 feet deep with a 10-12 inch casing. Elevation: 5520 ft.
- Well flow of approximately 500-800 gpm.

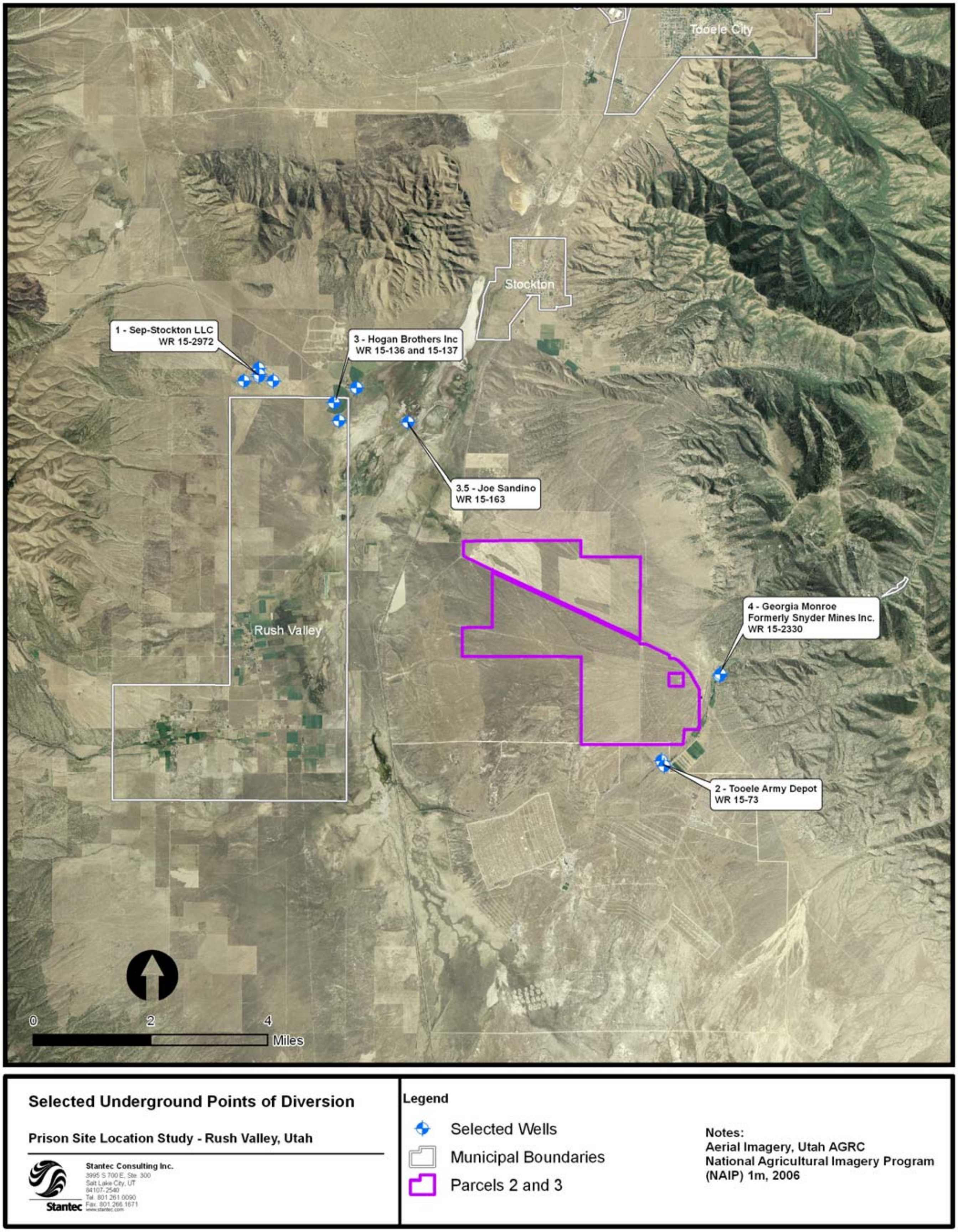


Figure 3.4 *Water Rights Map – Selected Underground Points of Diversion*

- 2 tanks with 750,000 gallons of storage each. Elevation: 5540 ft.
- 12 inch water supply line, Length: 7,200 feet, Elevation drop: 160 feet.
- A water supply loop inside the fence in each complex.
- The prison site at an elevation range of: 5400 ft to 5300 ft.

The system can potentially be served by gravity flow if the site is arranged with the elevations and pipe sizes recommended above.

The water storage tanks were sized to provide a 1 day supply of stored water and adequate water storage to provide a fire flow 1500 gpm for 2 hours.

The water supply line was sized to provide a peak service flow of 1,600 gpm and allow for service pressure of 50 to 80 psi at the prison site through gravity flow. Pipeline head loss calculations for the main water supply line were based on High Density Polyethylene (HDPE) pipe material (roughness coefficient, C, of 145), a flow rate of 1,600 gpm, an elevation loss of 160 feet, and a total pipe length of 7,200 feet. Input variables and output pressure values are shown in Table S2.

Table 3.1 Main Water Supply Line Headloss

Roughness, C	145
Length, L	7,200 feet
Flowrate, Q	1,600 gpm
Inside Diameter, D	12 inches
Head Loss, h_L	36 feet
Service Pressure	Upper Prison (Elevation 5380), 54 psi
	Lower Prison (Elevation 5300), 80 psi

Water supply distribution infrastructure is shown in Figure 3.1.

WATER SYSTEM RECOMMENDATIONS

This preliminary fatal flaw and water supply analysis has identified the major water supply systems that will be required for the prison site. More detailed studies of these systems will need to be performed. These future studies include:

- A detailed water demands analysis to determine design demands for water capacity and storage requirements.
- A detailed hydrogeologic study including a well siting study and a test well program.
- A detailed site layout with grading plans and infrastructure designs.

SANITARY SEWER AND WASTEWATER ANALYSIS

The sanitary sewer and wastewater analysis included an investigation of the site constraints and potential for a slow percolation system and the production of crops from recycled wastewater. Preliminary major sewer collection lines have been drawn and a proposed treatment plant site location has been shown in Figure 3.1. Wastewater flow rates have been determined based on a 6,000 bed facility and a 10,000 bed facility. A conceptual wastewater system has been determined.

The conceptual wastewater system includes:

- Major wastewater collection lines (approximately 6,300 feet in total length).
- A wastewater treatment plant with a flow rate of 0.7 MGD for a 6,000 bed facility and 1.15 MGD for a 10,000 bed facility. Located at an elevation of 5280 ft.
- A wastewater storage pond that is 15 acres for a 6,000 bed facility and 25 acres for a 10,000 bed facility and 15 feet deep in total. Elevation: 5240 ft.
- A gravity flow irrigation line that is approximately 4,900 feet long.
- An irrigated area of approximately 350 acres. Elevation: 5140 ft to 5060 ft.

The wastewater storage pond was sized to allow adequate storage for the non-irrigation season.

WASTEWATER TREATMENT ALTERNATIVES

Two major wastewater treatment alternatives were investigated in this study. These include:

- An Oxidation Ditch Process with Mechanical Sludge Dewatering.
- Membrane Bio-Reactor (MBR) Process with Mechanical Sludge Dewatering.

- Both of these options are capable of producing Type I water, which can be used to irrigate food crops.

MBR Plant Process Outline

The MBR Plant depicted in Figure 3.5 and Figure 3.6, consists of:

- Influent Pump Station.
- Headworks with Grit Collector and Bar Screen.
- Anoxic Tank for De-Nitrification.
- Aerated Activated Sludge with Membrane Filter System.
- Waste Sludge Handling.
- Chlorination Disinfection.
- Sludge Handling Equipment.
- Recycled Water Storage Pond.
- Recycled Water System.

The influent lift station consists of submersible pumps or screw pumps to run the raw water through the headworks of the plant. The pumps would need to be capable of handling 4" solids and provide enough head to pump the influent. The headworks are usually placed after the influent lift station and include a bar screen system to remove larger solids and a grit collector tank to settle out finer solids.

After the passing through the headworks, the water flows into the process tanks. In a typical MBR system, there are three major processes: an anoxic tank, an aerobic tank, and a membrane filtration system. The anoxic tank is typically the first step, followed by an aeration basin, followed by membrane filtration. The solids in the MBR tank are recycled back to the anoxic basin through a return line. MBR systems are typically run at mixed liquor suspended solids (MLSS) concentrations of 10,000 mg/L, which are higher than more conventional methods of wastewater treatment. This feature allows the plant to produce the same level of treatment in a smaller footprint.

The anoxic tank is typically well mixed but is not aerated. The suspended solids recycle line feeds into this tank. The solids are recycled from the membrane filtration process. The anoxic tank is essential for de-nitrification, a process that removes nitrate from the water and improves effluent quality. The aerobic tank provides aerobic breakdown of the wastewater as well as nitrification. This tank provides the breakdown of treatment by converting organic matter to substrate. The membrane filters provide the final filtration step that removes sludge and solids from the final effluent. This is the last step in the membrane system. Effluent is typically pumped by permeate pumps on the suction side of the filters and the effluent is sent to the storage pond or chlorine disinfection step. The membranes are constantly scoured by an aeration system within the filter casing to keep the filters clear of solids and the solids suspended in solution. The suspended solids are pumped back to the anoxic tank through Return Activated Sludge (RAS) pumps.

The plant also requires a sludge de-watering system and a sludge disposal method. There are many techniques for dewater sludge such as a belt press system, or a screw press system. Waste sludge can be sent to the landfill, composted on-site, or put into an anaerobic digester system. Due to the size of the prison site, composting of waste sludge would likely be the best option.

MBR plants combine clarification and tertiary filtration into one step. This feature allows the plant to be placed on a smaller footprint than a conventional plant. Plant flow rates are limited by the hydraulic capacity of the pump and piping systems, not the nutrient or BOD loading.

Membrane systems are costly and require replacement approximately every 10 years. Although no tertiary filters are required, disinfection must be incorporated into the process design to produce Type I, Recycled Water.

Oxidation Ditch Plant Process Outline

The Oxidation Ditch system shown in Figure 3.7 and Figure 3.8 consists of:

- Influent Pump Station.
- Headworks with Grit Collector and Bar Screen.
- Anoxic Region for De-nitrification.
- Oxidation Ditch with Aerated Activated Sludge.
- Conventional Circular Clarifiers.
- Waste Sludge and Return Activated Sludge System (RAS).
- Tertiary Filters.
- Chlorination Disinfection.

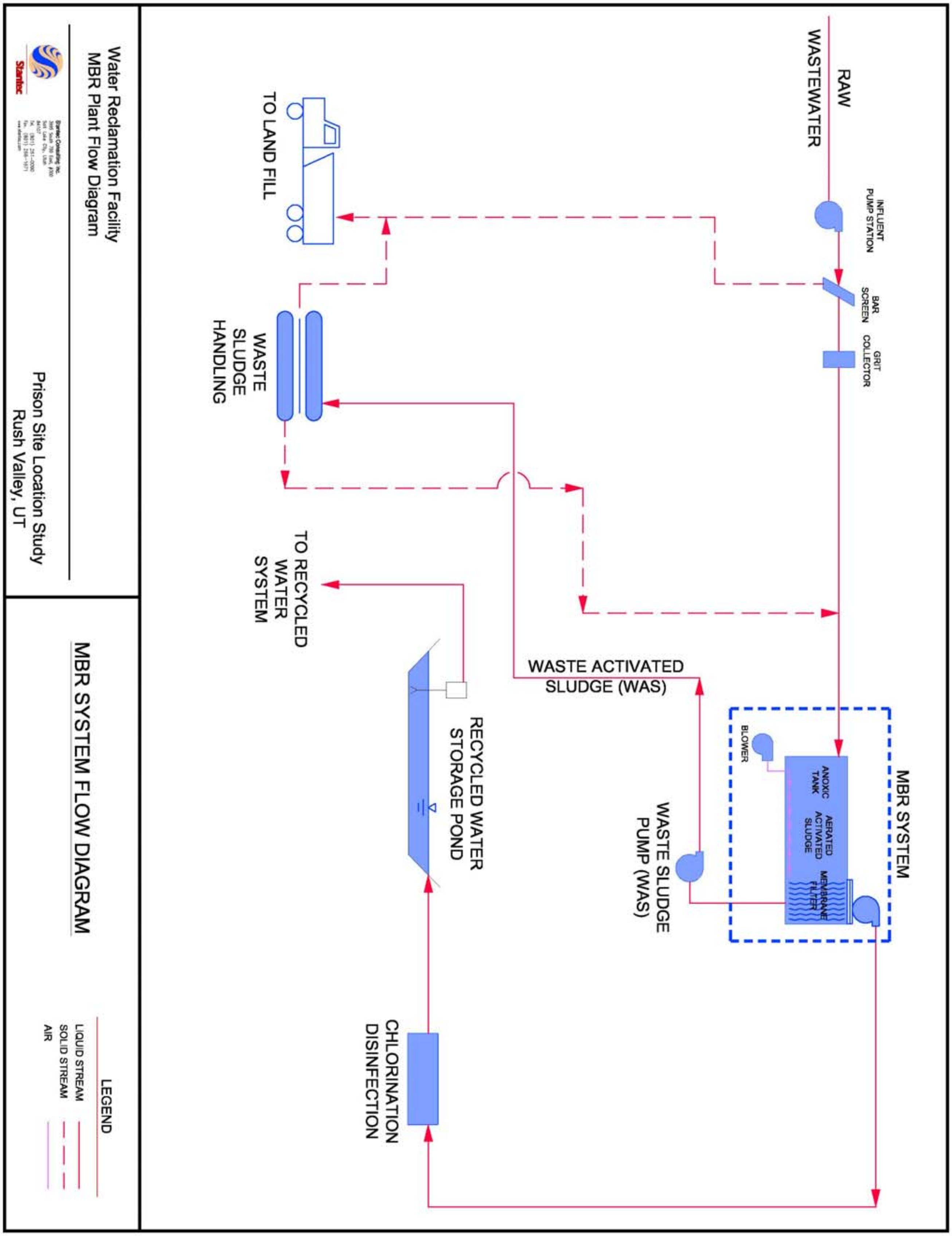


Figure 3.5 *MBR Process Flow Diagram*

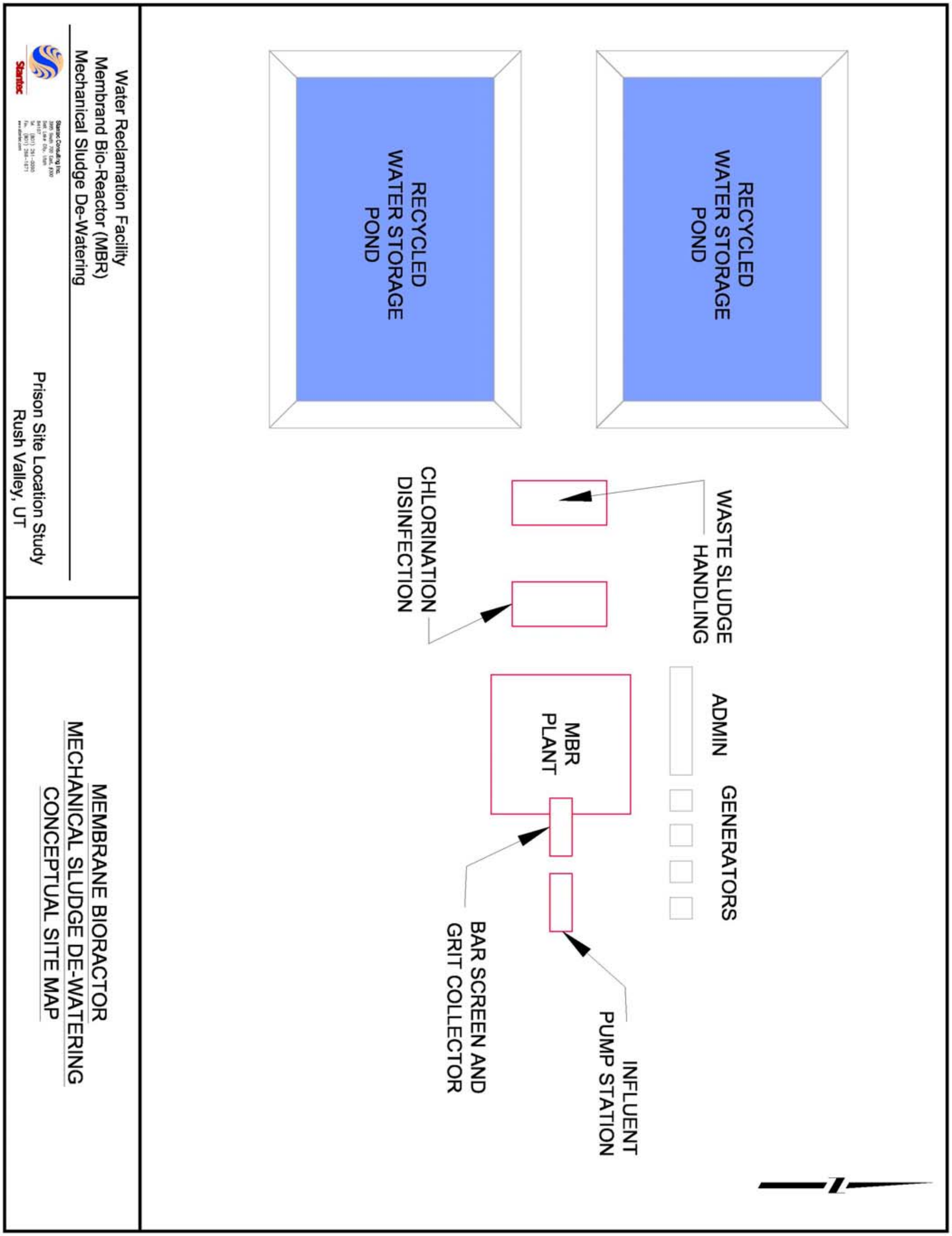


Figure 3.6 *MBR Site Plan*

- Sludge Dewatering System.
- Recycled Water Storage Pond.
- Recycled Water Pump Station.

The influent lift station and plant headworks are similar to the MBR system.

The aerated activated sludge basin (oxidation ditch) is typically larger than a MBR aeration basin. Oxidation ditches are usually circular trenches with brush-shaped aerators. RAS is recycled back into the oxidation ditch. Oxidation ditch MLSS concentrations are usually less than 4,000 mg/L. Due to the lower MLSS concentrations, a much larger footprint is required than a typical MBR plant.

The anoxic zone is similar to the MBR process and also serves as a method for de-nitrification.

Conventional clarifiers operate differently than an MBR process. Conventional clarifiers use settling instead of filtration to separate the solids. Clarifiers are typically circular in shape. Mixed Liquor (MLSS) from the oxidation ditch is sent to the clarifier bottom and effluent is allowed to flow over a weir into the effluent launder. A sludge recycling pump is located at the bottom of the clarifier that pumps the recycled sludge back to the oxidation ditch. These recycle pumps are typically centrifugal pumps.

The Oxidation Ditch system will produce Type II water at the end of the clarifier stage. Type II water has not undergone as much treatment as Type I water and cannot be used for food crops unless the water does not contact the food. In other words, sprinklers cannot be used. If Type II water is acceptable for a use other than crop irrigation, then further treatment at the tertiary filter will not be required. The tertiary filter will be employed if the desired use for the water requires Type I, Recycled Water. The probable capital cost for the 6,000 bed facility Oxidation Ditch Plant will be approximately $6.2 million. The probable capital cost for the 10,000 bed facility Oxidation Ditch Plant will be approximately $10.3 million. These values may be considered average values for all proposed processes. Details on the estimates can be seen in Tables 3.2 and 3.3.

LEED CERTIFICATION

There is a Leading Energy and Environmental Design (LEED) credit for wastewater technologies design. The intent of the credit is to reduce generation of wastewater and potable water demand, while increasing the local aquifer recharge. There are two options available for obtaining the credit; the second one is applicable to this project. Option 2 requires that 50% of the wastewater be treated on-site to tertiary standards and the treated water be used on-site. Both of the proposed treatment processes will be capable of treating 50% of the wastewater on-site. The credit will also be fulfilled if the treated water is used for crop irrigation.

RECYCLED WATER ANALYSIS

The wastewater system at the proposed prison site will require a wastewater disposal system. Such disposal could consist of a rapid infiltration system or a slow percolation system. A rapid infiltration system will provide wastewater disposal into unlined disposal ponds. This option would provide rapid wastewater disposal but would not provide irrigation benefits. This system may be desirable in situations where excess wastewater is produced or irrigated land is not available. A slow percolation system provides wastewater disposal through an irrigation system. This provides a secondary benefit as irrigation water. Disposed water can be used to irrigate crops or landscaping.

Due to the availability of area for irrigation on the property, the prison site would be amenable to a slow percolation system. Slow percolation would allow for the production of crops such as alfalfa that would assist in the disposal of water and nutrients through consumption. Re-use water may be used to produce crops for food purposes and irrigate landscaped areas. Water treatment requirements differ depending on the purpose of the reuse water.

The definition of Type II water and its irrigation uses is shown below in Utah State Regulation R-317-3-11:
11.5 Use of Treated Domestic Wastewater Effluent Where Human Exposure is Unlikely (Type II)

A. Uses Allowed

1. *Irrigation of sod farms, silviculture, limited access highway rights of way, and other areas where human access is restricted or unlikely to occur.*
2. *Irrigation of food crops where the applied treated effluent is not likely to have direct contact with the edible part, whether the food will be processed or not (spray irrigation not allowed).*

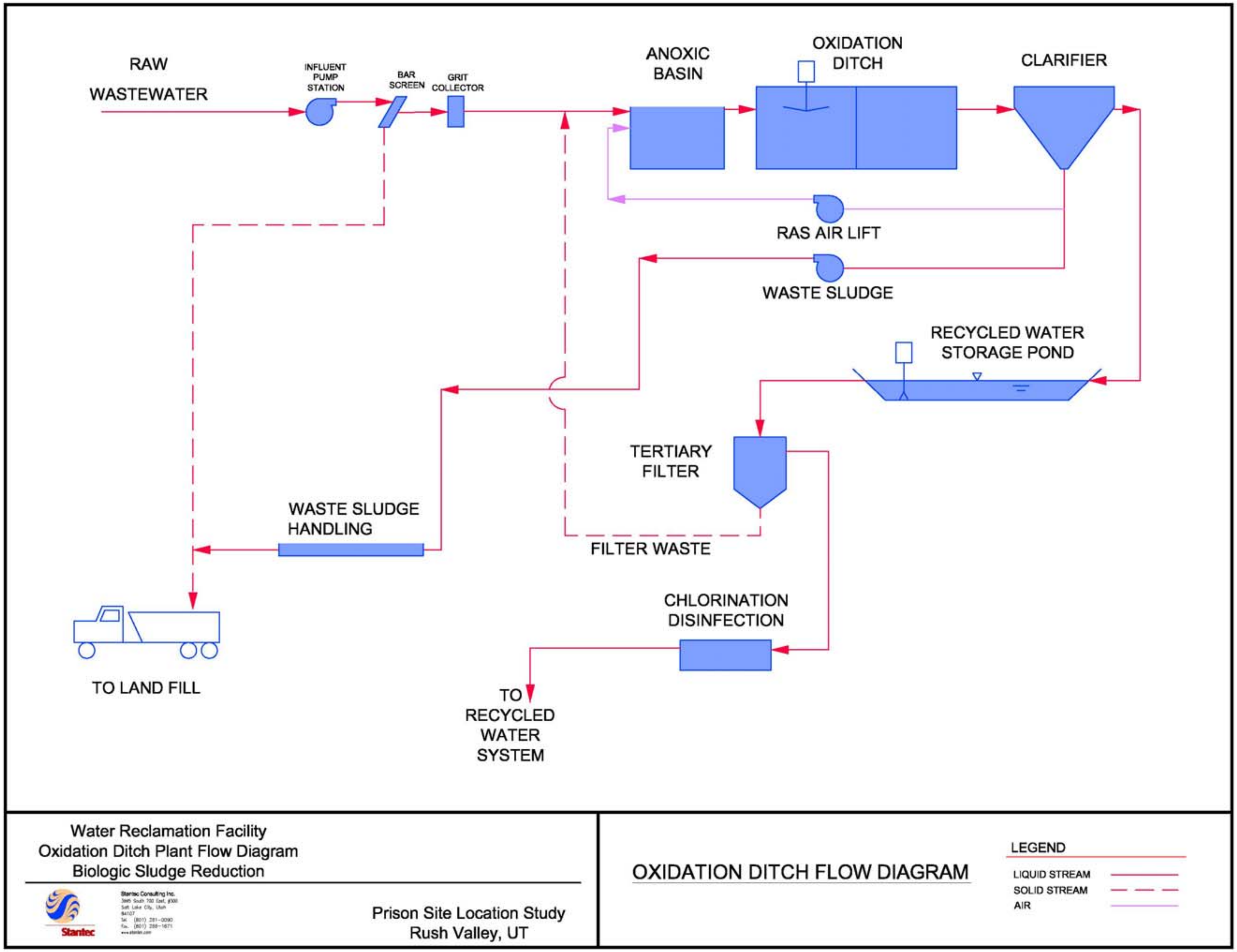


Figure 3.7 *Oxidation Ditch Process Flow Diagram*

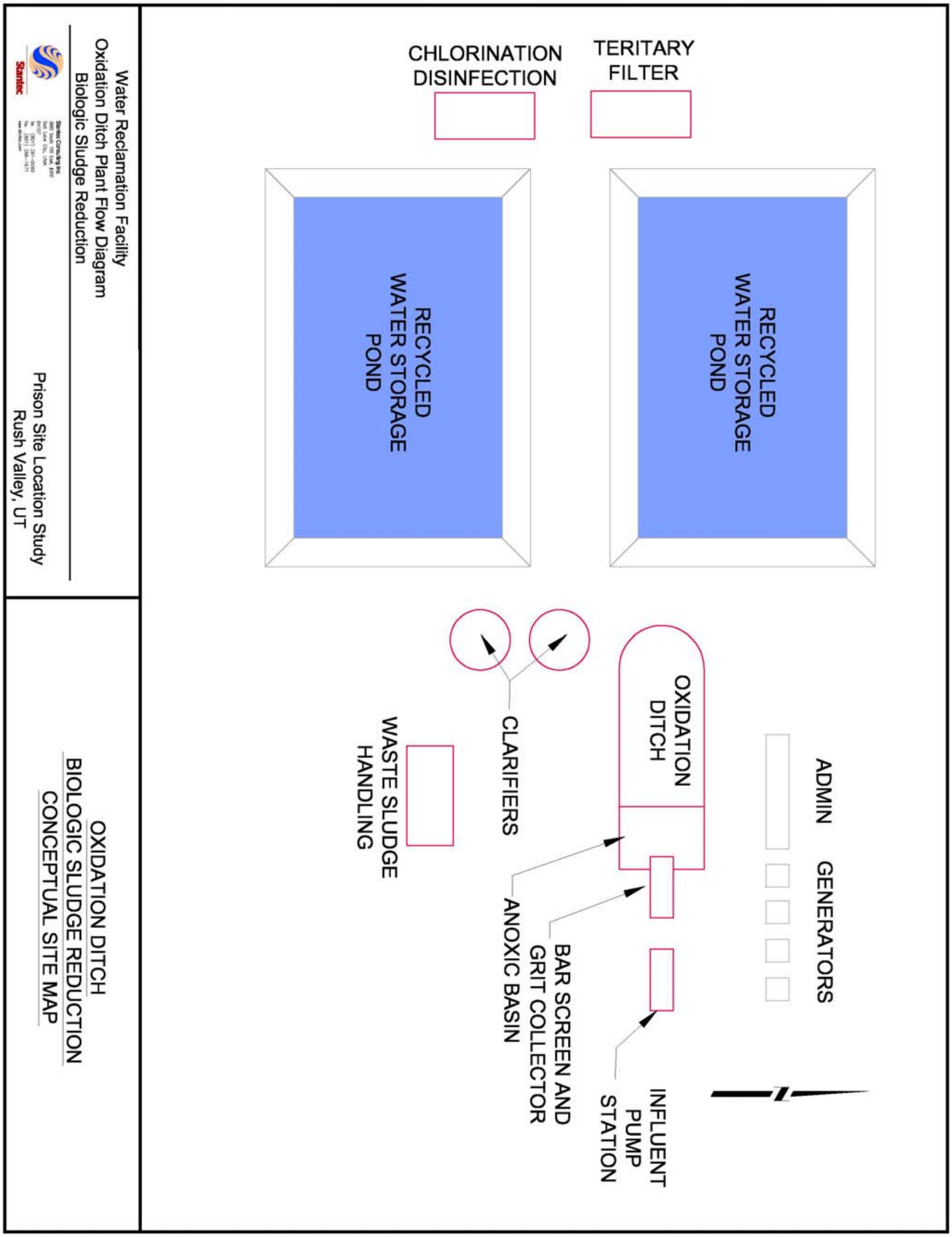


Figure 3.8 *Oxidation Ditch Site Plan*
]

Table 3.2 *Opinion of Probable Construction Cost Summary*
(Mechanical Sludge Dewatering System)
(6,000 Bed Facility, 0.7 MGD Flowrate)

LINE NO.	**Direct Construction Costs**		**Item Totals**	**Project Totals**
00	General Plant Site Work		$249,000	
01	Influent Submersible Pump Station		$76,800	
02	Headworks		$353,400	
03	Oxidation Ditch		$587,400	
04	Clarifiers		$396,000	
05	RAS Pump System		$75,000	
07	Effluent Pump Station		$94,800	
08	Sludge Dewatering and Processing		$1,057,200	
09	Disposal Pump Station		$54,000	
10	Storage Lagoon		$1,655,400	
11	Gas Chlorination Disinfection System		$18,000	
12				
13		**Direct Construction Cost Subtotal**	**$4,617,000**	$4,617,000
14				
15	**In-Direct Construction Costs**			
16	Miscellaneous = 5%		$231,000	
17		**Sub Total**	**$231,000**	
18	Engineering = 12%		$581,760	
19		**Sub Total**	**$812,760**	
20	MOB / DE-MOB = 5%		$231,000	
21	Contingency = 5%		$271,000	
22	Admin & Legal = 5%		$231,000	
23	**In-Direct Construction Cost Subtotal**		**$1,546,000**	$1,546,000
24		**Total Project Construction Cost:**		**$6,163,000**

Table 3.3 *Opinion of Probable Construction Cost Summary*
(Mechanical Sludge Dewatering System)
(10,000 Bed Facility, 1.15 MGD Flowrate)

LINE NO.	**Direct Construction Costs**		**Item Totals**	**Project Totals**
00	General Plant Site Work		$415,000	
01	Influent Submersible Pump Station		$128,000	
02	Headworks		$589,000	
03	Oxidation Ditch		$979,000	
04	Clarifiers		$660,000	
05	RAS Pump System		$125,000	
07	Effluent Pump Station		$158,000	
08	Sludge Dewatering and Processing		$1,762,000	
09	Disposal Pump Station		$90,000	
10	Storage Lagoon		$2,759,000	
11	Gas Chlorination Disinfection System		$30,000	
12				
13		**Direct Construction Cost Subtotal**	**$7,695,000**	$7,695,000
14				
15	**In-Direct Construction Costs**			
16	Miscellaneous = 5%		$385,000	
17		**Sub Total**	**$385,000**	
18	Engineering = 12%		$969,600	
19		**Sub Total**	**$1,354,600**	
20	MOB / DE-MOB = 5%		$385,000	
21	Contingency = 5%		$452,000	
22	Admin & Legal = 5%		$385,000	
23	**In-Direct Construction Cost Subtotal**		**$2,577,000**	$2,577,000
24		**Total Project Construction Cost:**		**$10,272,000**

3. Irrigation of animal feed crops other than pasture used for milking animals.

4. Impoundments of wastewater where direct human contact is not allowed or is unlikely to occur.

5. Cooling water. Use for cooling towers which produce aerosols in populated areas may have special restrictions imposed.

6. Soil compaction or dust control in construction areas.

B. Required Treatment Processes

1. Treatment processes that are expected to produce effluent in which both the BOD and total suspended solids concentrations do not exceed secondary quality effluent limits as defined in R317-1-3.2.

2. Disinfection to destroy, inactivate, or remove pathogenic microorganisms by chemical, physical, or biological means. Disinfection may be accomplished by chlorination, ozonation, or other chemical disinfectants, UV radiation, or other approved processes.

The definition of Type I water and its irrigation uses is shown below in Utah State Regulation R-317-3-11:

11.4 Use of Treated Domestic Wastewater Effluent Where Human Exposure is Likely (Type I)

A. Uses Allowed

1. Residential irrigation, including landscape irrigation at individual houses.

2. Urban uses, which includes non-residential landscape irrigation, golf course irrigation, toilet flushing, fire protection, and other uses with similar potential for human exposure. Internal building uses of treated effluent will not be allowed in individual, wholly-owned residences; and are only permitted in situations where maintenance access to the building's utilities is strictly controlled and limited only to the services of a professional plumbing entity. Projects involving effluent reuse within a building must be approved by the local building code official.

3. Irrigation of food crops where the applied reuse water is likely to have direct contact with the edible part. Type I water is required for all spray irrigation of food crops.

4. Irrigation of pasture for milking animals.

5. Impoundments of wastewater where direct human contact is likely to occur.

6. All Type II uses listed in 11.5.A below.

B. Required Treatment Processes

1. Treatment processes that are expected to produce effluent in which both the BOD and total suspended solids concentrations do not exceed secondary quality effluent limits as defined in R317-1-3.2.

2. Filtration, which includes passing the wastewater through filter media such as sand and/or anthracite, approved membrane processes or other approved filtration processes.

3. Disinfection to destroy, inactivate, or remove pathogenic microorganisms by chemical, physical, or biological means. Disinfection may be accomplished by chlorination, ozonation, or other chemical disinfectants, UV radiation, or other approved processes.

Type II water can be used to irrigate non-contact food crops and animal feed crops such as alfalfa. Type II water is defined as water that meets effluent BOD and TSS standards and has undergone a disinfection step. This water has not undergone a final tertiary filtration step.

Type I water can be used for irrigation of food crops, parks, golf courses, and landscaped areas. Table 3.4 shows the crop consumptive use on a monthly basis. For the purposes of this study, preliminary crop water consumption and re-use water storage pond requirements have been calculated. Crop water consumption was estimated by using the following data:

- Evaporation data.
- Crop consumption data
- Mean monthly temperature
- % of Daytime Hours with consumption
- Deep Percolation

The K value shown in Table 3.4 is an indicator of the amount of water that the crops will require during the respective month. A higher K value indicates that more water will be consumed by the crop. The percent of daytime hours is the percent of time during the day that irrigation is required. The mean monthly temperature was also utilized in calculating the crop consumptive use. Table 3.4, Table 3.5, Table 3.6, and Figure 3.9 illustrate the storage pond and irrigation calculations.

Recycled water storage will also be a major consideration. A treated wastewater pond is proposed to the northwest of the proposed treatment plant. This pond will have a maximum surface area of 25 acres and depth of 15 feet. This size will allow an area of approximately 350 acres to produce crops with irrigation. The pond will be constructed at an elevation of 5240 feet. This will allow for a 12” irrigation line to run on gravity to the proposed irrigation area with a maximum elevation of 5140 feet. The irrigation system could potentially be served by gravity flow and the site would have a minimum elevation of 5,060 feet. (See Figure 3.1)

FUTURE PLANT EXPANSION

The prison site wastewater infrastructure has been estimated for a 6,000 bed facility with the potential for expansion to a 10,000 bed facility in mind. This expansion will affect the way that the initial treatment plant will be designed. The main process infrastructure, influent headworks, and pump stations will need to be designed for the 10,000 bed flow rate.

The storage pond system can be easily phased to accommodate prison expansion. The easiest way to do this is through a multiple pond system. Pond storage size can be scaled in proportion to the wastewater flow rate. Initial pond storage will require 15 acres of pond area and future expansion will require 25 acres. Multiple 5-acre ponds could be constructed in phases to accommodate these storage requirements.

Table 3.5 Wastewater Storage Pond Calculations

Site name:	**STATE PRISON**
Location:	**RUSH VALLEY, UTAH**
System average daily flow: (MG/D)	**1.15**
Yearly evaporation rate: (in/year):	73.76
Total lake and free water surface area:	25.00
Lagoon Depth (ft.)	15.0
Landscape acreage:	350.00
Summer crop:	**Alfalfa**
Winter crop:	**Alfalfa**
Estimated Storage required (gal./mo.):	95,461,600
Water balance total/year:	(1,265,148)

A positive value indicates insufficient water usage, a negative value is indicated by (parentheses).

Table 3.4. *Crop Consumptive Use*

Month	K Value	% Daytime Hours	Mean Monthly Temperature (°F)
January	0.00	7.10	26.7
February	0.00	6.91	29.9
March	0.48	8.35	37.1
April	0.58	8.80	46.4
May	0.64	9.71	55.9
June	0.75	9.71	64.6
July	0.80	9.88	74.5
August	0.80	9.34	72.8
September	0.80	8.35	62.9
October	0.64	7.90	50.5
November	0.48	7.02	36.5
December	0.00	6.93	29.9

Source: Blaney, H.F., and Criddle, W.D., 1962, Determining Consumptive Use Irrigation Water Requirements. USDA Technical Bulletin Number 1275, 59 pages.

Table 3.6 *Water Balance Spreadsheet*

	Monthly effluent available: gallons:	Rainfall inches per month:	Rainfall gallons per month:	Total evaporation: gallons per month:	System leakage and percolation if allowable: gallons per month:	Consumptive use of grasses: inches per acre:	Consumptive use of grasses: gallons per month:	Consumptive use of trees: gallons per month:	Total landscape water demand: gallons per month:	Total water available: gallons per month:	Net water balance gallons per month:
January	35,650,000	0.95	9,673,043	0	28,470,750	0.00	0	0	0	16,852,293	16,852,293
February	32,200,000	0.94	9,571,221	0	28,470,750	0.00	0	0	0	13,300,471	13,300,471
March	35,650,000	1.45	14,764,118	2,484,445	28,470,750	1.49	14,131,162	0	14,131,162	19,458,923	5,327,760
April	34,500,000	1.58	16,087,797	4,208,622	9,490,250	2.35	22,327,041	0	22,327,041	36,888,925	14,561,884
May	35,650,000	1.63	16,596,905	6,238,264	9,490,250	3.47	32,983,645	0	32,983,645	36,518,391	3,534,746
June	34,500,000	1.00	10,182,150	8,064,263	9,490,250	4.68	44,475,261	0	44,475,261	27,127,637	(17,347,624)
July	35,650,000	0.85	8,654,828	9,774,864	9,490,250	5.89	55,960,228	0	55,960,228	25,039,714	(30,920,514)
August	35,650,000	0.72	7,331,148	8,600,523	9,490,250	5.44	51,659,016	0	51,659,016	24,890,375	(26,768,641)
September	34,500,000	0.49	4,989,254	5,824,190	9,490,250	4.20	39,930,374	0	39,930,374	24,174,814	(15,755,560)
October	35,650,000	1.18	12,014,937	3,299,017	9,490,250	2.55	24,240,664	0	24,240,664	34,875,670	10,635,007
November	34,500,000	1.34	13,644,081	1,574,839	28,470,750	1.23	11,672,185	0	11,672,185	18,098,492	6,426,307
December	35,650,000	1.15	11,709,473	0	28,470,750	0.00	0	0	0	18,888,723	18,888,723
SUMS:	419,750,000	13.28	135,218,952	50,069,026	208,785,500	31.29	297,379,575	0	297,379,575	296,114,426	(1,265,148)

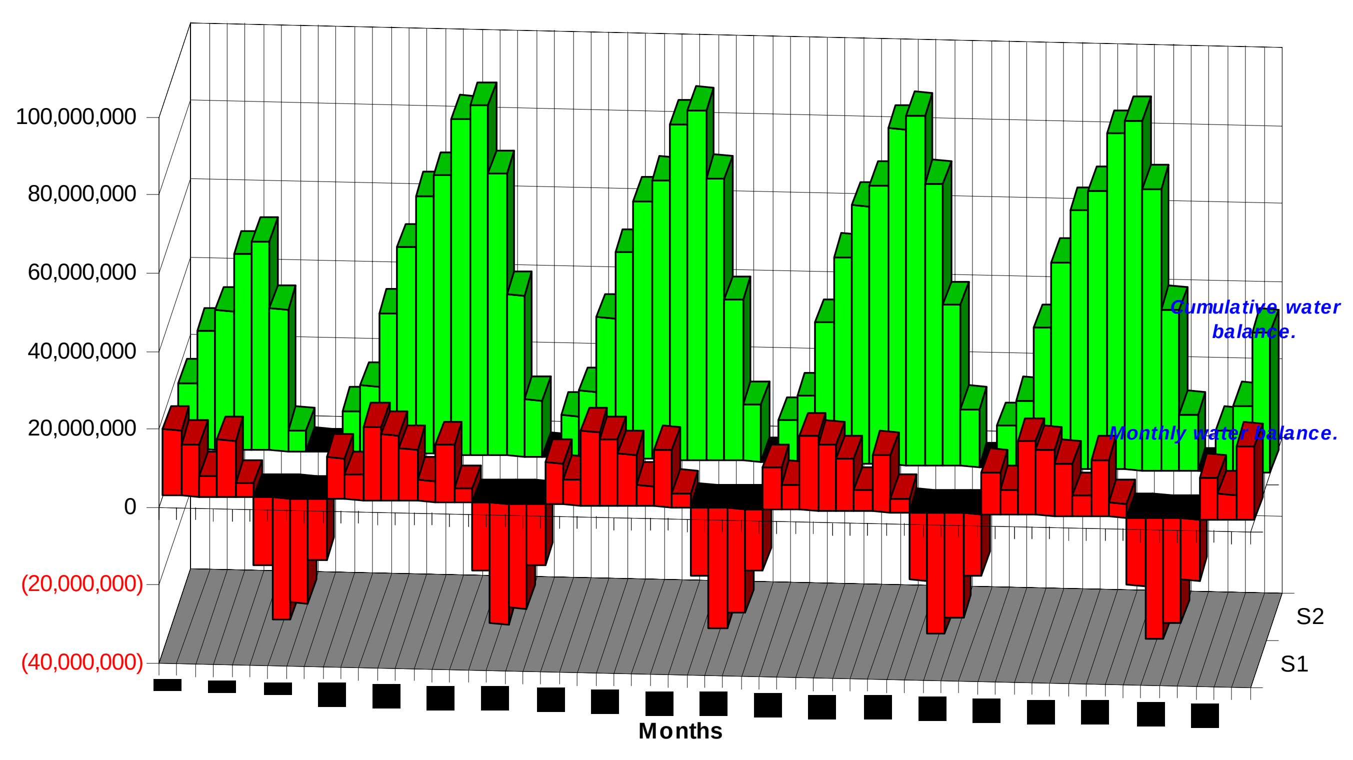


Figure 3.9 *Monthly Water Balance (Red) and Cumulative Water Balance (Green), the Y-axis is in gallons.*

NATURAL GAS ANALYSIS

There are currently multiple 8” high pressure natural gas lines that cross through the proposed prison site on Highway 73. The prison site would require an 8” supply line with a minimum of 50 psi. According to the Questar Gas Company (Questar), the existing gas supply lines under Highway 73 would provide adequate supply to the proposed site. Adequate gas supply was determined by Questar in their supply model. This assumption was based on a 10,000 bed prison facility.

Cost estimates have been provided by Questar to construct a new gas connection and any required piping. Questar supplied gas construction would include tapping the existing high pressure main in Highway 73, and providing an 8” supply line to the site. This estimate does not include the onsite gas line distribution and sub-metering. See the site figure at the end of the document for gas line location information. The cost estimate provided by Questar for a new gas connection at the proposed prison site was: $31,000.

STORM DRAINAGE ANALYSIS

The storm drainage analysis looked at two different types of storm drainage systems—a detention pond system and a retention pond system. A detention pond system reduces peak stormwater flow rates in order to reduce the potential for downstream flooding and erosion. A retention pond system eliminates all stormwater discharges to surface water. Stormwater is infiltrated instead.

The analysis included a study of pre-development versus post-development runoff volumes and peak flow rates, major storm drainage line requirements, and detention or retention storage requirements. Consideration has also been given to meeting requirements for storm drainage credits to apply for Leadership in Energy and Environmental Design (LEED) certification. No re-use of stormwater for irrigation purposes was considered. This is due to the much greater volume of recycled wastewater and State regulations that prohibit the mixing of stormwater with recycled wastewater.

RUNOFF CALCULATIONS

Runoff volumes and peak flow rates were calculated based on the preliminary site layout. The area of roofs, parking lots, and landscaping were estimated and input into the rational runoff equation. This equation uses different runoff coefficients for each type of area, producing different runoff amounts for landscape area and roof area (see Table 3.7).

Table 3.7. *Roof, Pavement, and Landscape Area*

Description	Area (ft^2)
Roof	2,571,000
Pavement	452,000
Landscape	100,000
Total	**3,123,000 (72 acres)**

Rainfall data used in the runoff calculations is shown in Table S8. These data were used to estimate the intensity of rainfall and probability of rainfall events. Generally stormdrainage systems are designed to handle 10-year storm events. A ten year return interval indicates a 10 percent annual chance of occurrence.

Table 3.8. *Rainfall Data for 24-hour Rainfall Events*

Return Interval	Total Rainfall
1-year	1.11 in
2-year	1.55 in
10-year	2.23 in

Table 3.9 shows the peak runoff flow rates that were calculated for the site under pre-developed conditions and post-developed conditions. Stormwater detention ponds and retention ponds were preliminarily sized to reduce peak discharge rates to pre-development conditions.

Table 3.9. Pre-Development versus Post-Development Runoff

	Pre-Development	Post-Development
10-yr Peak Flow Rate	26 cfs	109 cfs
2-yr Peak Flow Rate	16 cfs	68 cfs

LEED CERTIFICATION

The intent of LEED certification for stormwater is to limit the disruption of natural hydrology be reducing impervious cover, increasing on-site infiltration, reducing or eliminating pollution from stormwater runoff, and eliminating contaminants. There are two LEED stormwater credits: Stormwater Design: Quantity Control, and Stormwater Design: Quality Control.

Stormwater Design: Quantity Control

The LEED Stormwater Design: Quality Control Requirements are shown below.

CASE 1 – Existing Imperviousness is less than or equal to 50%

> *Implement a stormwater management plan that prevents the post-development peak discharge rate and quantity from exceeding the pre-development peak discharge rate and quantity for the one- and two- year 24-hour design storms.*
>
> *OR*
>
> *Implement a stormwater management plant that protects receiving stream channels from excessive erosion by implementing a stream channel protection strategy and quantity control strategies. "LEED for New Construction & Major Renovations", U.S. Green Building Council.*

The preliminary storm drainage study for the prison site location has determined detention pond or retention pond requirements to meet the first half of this standard. Storm drainage detention ponds have been sized to retain stormwater to the predevelopment peak flow rate for one and two-year 24 hour design storms. These ponds will provide more retention storage than traditional design. This extra pond volume decreases peak flow rates and reduces the potential for erosion at the stormdrain discharge point. Additional retention storage improves discharge water quality due to additional solids settling.

Consideration was also given to a stormwater retention system. A system such as this would provide water quality treatment as well as infiltration and groundwater recharge. It would require larger ponds to allow adequate time for infiltration, but would provide more treatment than a detention system. It would also mimic a natural drainage system because it allows stormwater to infiltrate back into the groundwater like a natural drainage system.

Stormwater Design: Quality Control

The LEED Stormwater Design: Quality Control Requirements are shown below:

> *Implement a stormwater management plant that reduces impervious cover, promotes infiltration, and captures and treats the stormwater runoff from 90% of the average annual rainfall using acceptable best management practices (BMPs). BMPs used to treat runoff must be capable of removing 80% of the average annual post development total suspended solids (TSS) load based on existing monitoring reports. BMPs are considered to meet these criteria if (1) they are designed in accordance with standards and specifications from a state or local program that has adopted these performance standards, or (2) there exists in-field performance monitoring data demonstrating compliance with the criteria. Data must conform to accepted protocol (e.g., Technology Acceptance Reciprocity Partnership [TARP], Washington State Department of Ecology) for BMP monitoring.*
> *"LEED for New Construction & Major Renovations", U.S. Green Building Council.*

The LEED requirements encourage the use of alternative surfaces such as vegetated roofs and pervious pavement and nonstructural techniques such as vegetated swales, and disconnected imperviousness. They also promote stormwater quality design strategies such as constructed wetlands, settling ponds, and vegetated filters and open channels.

Stantec recommends that the prison site consider the use of stormwater quality measures. These include drainage structures such as stormwater swales, wet settling ponds, and filter fabrics that provide increased detention time, additional solids removal, and increased residence time to treat contaminants. Many of these structures can be included with landscape features and water features. Such structures have additional maintenance requirements but have major environmental quality benefits.

DETENTION PONDS

Stormwater detention ponds were sized to reduce peak runoff potential to pre-development levels during a 10-year event. These pond sizes are:

- A 1.9 acre-foot pond (5 ft deep, 140ft x 140 ft) on the Men's side.
- A 0.2 acre-foot pond (5 ft deep, 20ft x 20 ft) on the Women's side.

These ponds would reduce peak runoff flow rates to pre-development levels. Ponds would discharge to existing swales. See the following sizing calculations for more detail.

RETENTION PONDS

Stormwater retention ponds would require more available volume than the detention ponds. Retention ponds have been sized to retain 2-yr 24-hour storm events. Two stormwater retention ponds have been sized for the site, they include:

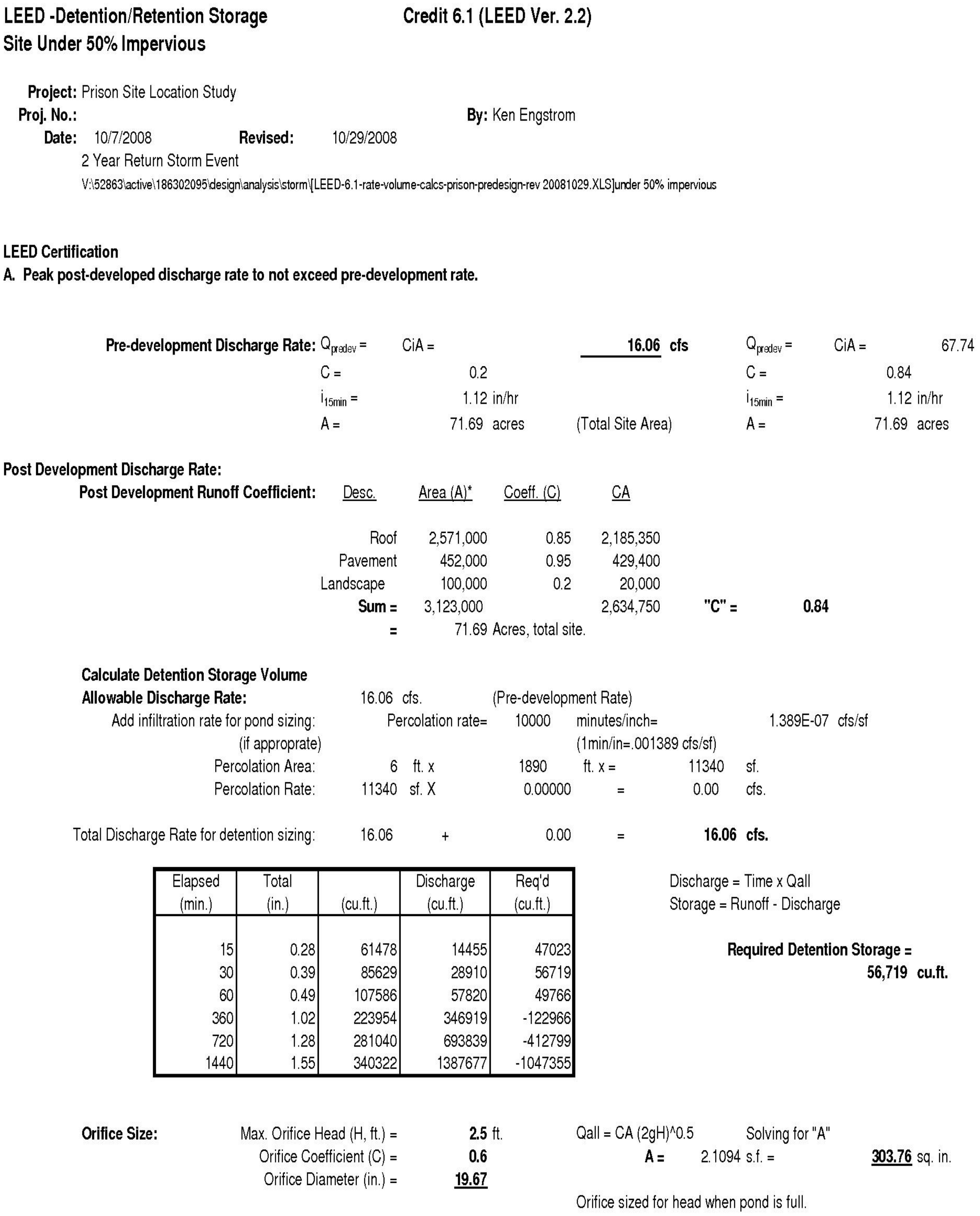
- A 5.0 acre-foot pond (5 ft deep 270 ft x 135 ft) on the Men's side.
- A 0.5 acre-foot pond (5 ft deep 70 ft x 35 ft) on the Women's side.

These retention ponds would allow one-year and two-year storm events to infiltrate into groundwater and not discharge into surface water. See the following sizing calculations for more detail.

STORM DRAIN COLLECTION SYSTEM

A storm drain collection system will be required to convey stormwater to the ponds. The major storm drain lines will need to be designed for a 10-year flow rate of 109 cfs. This will require a 36" diameter main trunk line with a minimum slope of 2.7%. Smaller stormdrain lines would be located on the uphill side of the site and the larger lines on the downhill side. The storm drain inlets would be located in the prison yard, near building runoff collection systems and parking lots. Security would be required for the lines within the fenced perimeter.

The stormdrain collection system would utilize vegetated swales where possible and infiltration trenches along storm drain pipe routes. Existing drainage pathways would be routed around the uphill side of the prison site and be separate from the storm drain system. These measures will potentially reduce the runoff load on the storm drain collection system.



LEED -Detention/Retention Storage **Credit 6.1 (LEED Ver. 2.2)**
Site Under 50% Impervious

Project: Prison Site Location Study
Proj. No.: **By:** Ken Engstrom
Date: 10/7/2008 **Revised:** 10/29/2008
2 Year Return Storm Event
V:\52863\active\186302095\design\analysis\storm\[LEED-6.1-rate-volume-calcs-prison-predesign-rev 20081029.XLS]under 50% impervious

LEED Certification
A. Peak post-developed discharge rate to not exceed pre-development rate.

Pre-development Discharge Rate:	Q_{predev} =	CiA =		**16.06 cfs**	Q_{predev} =	CiA =	67.74	
	C =	0.2			C =	0.84		
	i_{15min} =	1.12	in/hr		i_{15min} =	1.12	in/hr	
	A =	71.69	acres	(Total Site Area)	A =	71.69	acres	

Post Development Discharge Rate:

Post Development Runoff Coefficient:	Desc.	Area (A)*	Coeff. (C)	CA		
	Roof	2,571,000	0.85	2,185,350		
	Pavement	452,000	0.95	429,400		
	Landscape	100,000	0.2	20,000		
	Sum =	3,123,000		2,634,750	**"C" =**	**0.84**
	=	71.69	Acres, total site.			

Calculate Detention Storage Volume
Allowable Discharge Rate: 16.06 cfs. (Pre-development Rate)
Add infiltration rate for pond sizing: (if appropate) Percolation rate= 10000 minutes/inch= 1.389E-07 cfs/sf (1min/in=.001389 cfs/sf)
Percolation Area: 6 ft. x 1890 ft. x = 11340 sf.
Percolation Rate: 11340 sf. X 0.00000 = 0.00 cfs.

Total Discharge Rate for detention sizing: 16.06 + 0.00 = **16.06 cfs.**

Elapsed (min.)	Total (in.)	(cu.ft.)	Discharge (cu.ft.)	Req'd (cu.ft.)
15	0.28	61478	14455	47023
30	0.39	85629	28910	56719
60	0.49	107586	57820	49766
360	1.02	223954	346919	-122966
720	1.28	281040	693839	-412799
1440	1.55	340322	1387677	-1047355

Discharge = Time x Qall
Storage = Runoff - Discharge

Required Detention Storage =
56,719 cu.ft.

Orifice Size:
Max. Orifice Head (H, ft.) = **2.5** ft.
Orifice Coefficient (C) = **0.6**
Orifice Diameter (in.) = **19.67**

Qall = CA (2gH)^0.5 Solving for "A"
A = 2.1094 s.f. = **303.76** sq. in.

Orifice sized for head when pond is full.

Figure 3.10

LEED -Detention/Retention Storage Site Under 50% Impervious

Credit 6.1 (LEED Ver. 2.2)

Project: Prison Site Location Study
Proj. No.:
By: Ken Engstrom
Date: 10/7/2008 **Revised:** 10/29/2008
2 Year Return Storm Event
V:\52863\active\186302095\design\analysis\storm\[LEED-6.1-rate-volume-calcs-prison-predesign-rev 20081029.XLS]under 50% impervious

B. Post-developed discharge quantity is not to exceed the pre-developed discharge quantity.

2 year - 24 hour Storm total runoff = 1.55 in. = 0.13 ft

C_{predev} = 0.20 $C_{postdev}$ = 0.84

A = 3,123,000 sf = 71.69 Acres, total site.

Predev V_{tot} = C_{predev} * total runoff * A = 80,678 ft^3

Postdev V_{tot} = $C_{postdev}$ * total runoff * A = 340,322 ft^3

Retention Volume Required: V_{retain} = Postdev V_{tot} - Predev V_{tot} = **259,644** **ft^3**

C. Storage Volumes Provided:

Detention Pond Volume Estimate:

		width (ft)		length (ft)
Area (top) =	25088 ft^2	112	x	224
Area (bot) =	20808 ft^2	102	x	204
Depth =	2.5 ft			

Detention Pond Vol. = $(d/3)*A_T+A_B+(AT*AB)^{1/2}$ = **57,287** ft^3

This is greater than 56,719 ft^3 required.

Retention Pond Volume Estimate:

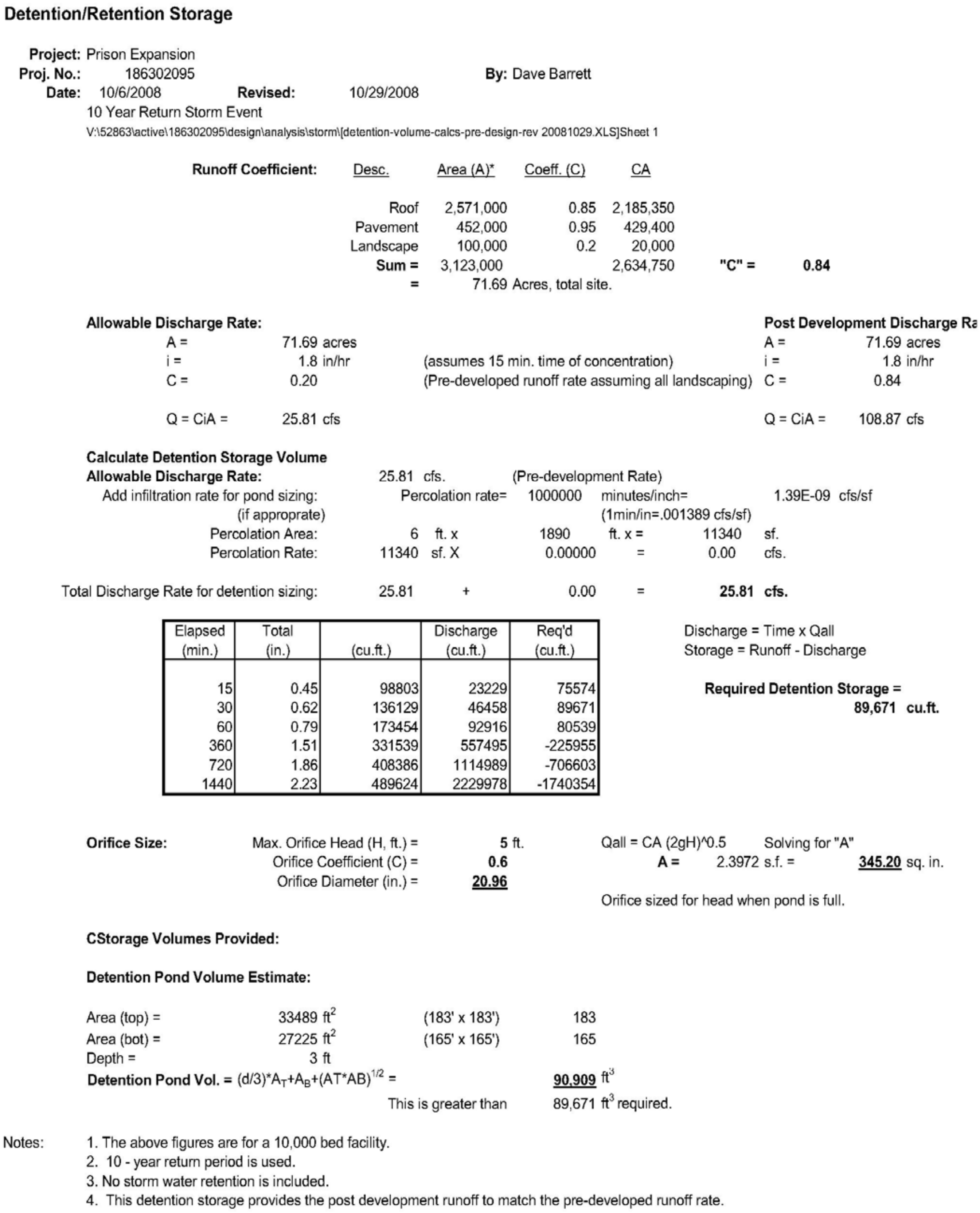
		width (ft)		length (ft)
Area (top) =	55278.125 ft^2	166	x	332.5
Area (bot) =	48828.125 ft^2	156	x	312.5
Depth =	5 ft			

Retention Pond Vol. = $(d/3)*A_T+A_B+(AT*AB)^{1/2}$ = **260,099** ft^3

This is greater than 259,644 ft^3 required.

Notes:
1. The above figures are for a 10,000 bed facility.
2. 2 - year return period is used.
3. This detention storage provides the post development runoff to match the pre-developed runoff rate.

Figure 3.11



Detention/Retention Storage

Project: Prison Expansion
Proj. No.: 186302095 **By:** Dave Barrett
Date: 10/6/2008 **Revised:** 10/29/2008
10 Year Return Storm Event
V:\52863\active\186302095\design\analysis\storm\[detention-volume-calcs-pre-design-rev 20081029.XLS]Sheet 1

Runoff Coefficient:

Desc.	Area (A)*	Coeff. (C)	CA
Roof	2,571,000	0.85	2,185,350
Pavement	452,000	0.95	429,400
Landscape	100,000	0.2	20,000
Sum =	3,123,000		2,634,750
=	71.69 Acres, total site.		

"C" = **0.84**

Allowable Discharge Rate:
A = 71.69 acres
i = 1.8 in/hr (assumes 15 min. time of concentration)
C = 0.20 (Pre-developed runoff rate assuming all landscaping)

Q = CiA = 25.81 cfs

Post Development Discharge Ra
A = 71.69 acres
i = 1.8 in/hr
C = 0.84

Q = CiA = 108.87 cfs

Calculate Detention Storage Volume
Allowable Discharge Rate: 25.81 cfs. (Pre-development Rate)
Add infiltration rate for pond sizing: Percolation rate= 1000000 minutes/inch= 1.39E-09 cfs/sf
(if approprate) (1min/in=.001389 cfs/sf)
Percolation Area: 6 ft. x 1890 ft. x = 11340 sf.
Percolation Rate: 11340 sf. X 0.00000 = 0.00 cfs.

Total Discharge Rate for detention sizing: 25.81 + 0.00 = **25.81 cfs.**

Elapsed (min.)	Total (in.)	(cu.ft.)	Discharge (cu.ft.)	Req'd (cu.ft.)
15	0.45	98803	23229	75574
30	0.62	136129	46458	89671
60	0.79	173454	92916	80539
360	1.51	331539	557495	-225955
720	1.86	408386	1114989	-706603
1440	2.23	489624	2229978	-1740354

Discharge = Time x Qall
Storage = Runoff - Discharge

Required Detention Storage =
89,671 cu.ft.

Orifice Size:
Max. Orifice Head (H, ft.) = **5** ft.
Orifice Coefficient (C) = **0.6**
Orifice Diameter (in.) = **20.96**

Qall = CA (2gH)^0.5 Solving for "A"
A = 2.3972 s.f. = **345.20** sq. in.

Orifice sized for head when pond is full.

CStorage Volumes Provided:

Detention Pond Volume Estimate:

Area (top) = 33489 ft^2 (183' x 183') 183
Area (bot) = 27225 ft^2 (165' x 165') 165
Depth = 3 ft
Detention Pond Vol. = $(d/3)*A_T+A_B+(AT*AB)^{1/2}$ = **90,909** ft^3
This is greater than 89,671 ft^3 required.

Notes:
1. The above figures are for a 10,000 bed facility.
2. 10 - year return period is used.
3. No storm water retention is included.
4. This detention storage provides the post development runoff to match the pre-developed runoff rate.

Figure 3.12

GEOLOGIC AND SOILS CONDITIONS

Geologic data availability for the Rush Valley area is limited, however a general geologic and soils investigation of available published literature was conducted. General geologic and soil conditions at the site were determined from the Natural Resource Conservation Service (NRCS) soil mapping data, Utah Automated Geographic Reference Center (AGRC) Geologic Hazards Layer and 1:100,000 scale US Geologic Survey (USGS) Geologic maps. See Figure 3.13 and Figure 3.14 for the geologic map and soils map.

The Utah AGRC geologic hazards map provides information on geologic hazards such as: Liquefaction, Surface Fault Rupture, Landslides, Rock Fall, Alluvial-Fan Flooding, and Problem Soils. No specific geologic hazards were identified at this site. The USGS Geologic maps describe the local deposits as unconsolidated Quaternary colluvium and alluvium (Qag) and conglomeratic deposits of uncertain age with low to high permeability (QTu). Deposits consist of a sand gravel conglomerate that includes a veneer of windblown sand.

The NRCS soils report identifies two types of soils on the site these consist of: Hiko Peak gravelly loam, 2 to 15 percent slopes (Map Unit 21) and Taylorsflat loam, 1 to 5 percent slopes (Map Unit 64). The majority of the soil on the site is Hiko Peak gravelly loam. This soil is formed from alluvial deposits and is classified as well drained. The soil has a low shrink swell potential and has no zone of water saturation within a depth of 72 inches. The soil is classified as “very limited” because it is not suitable for construction of small commercial buildings when slopes are steep. This is not an issue, however, on the proposed prison site, which has an average slope of only 3%. The soil map unit has slopes that vary from 2% to 15%. The building impairment is likely to occur at slopes greater than 8%.

The organic matter content in the surface of Hiko Peak soils is approximately 2 percent and the calcium carbonate equivalent within 40 inches of the surface typically does not exceed 35 percent. The soil has a moderately sodic horizon within 30 inches of the soil surface. The natural ecological site is classified as a Semidesert Gravelly Loam (Wyoming Big Sagebrush). The natural desert plant community consists of: Bluebunch wheatgrass, Wyoming Big Sagebrush, Indian Ricegrass, Shadscale, Bottlebrush Squirreltail, and Low Rabbitbrush.

Hiko Peak soil is classified as very limited for lawns and landscaping due to: sodium content, gravel content, slope, and large stones content. For irrigation yields, Hiko Peak soils are classified as type 4e, soils that have severe limitations that restrict the choice of plants or that require very careful management due to erosion potential. It is likely that erosion controls will have to be employed at the prison site.

The Taylorsflat loam soil, which is also at the site has similar engineering and agricultural characteristics but consists of mixed alluvial and lacustrine deposits.

These soil descriptions are general classifications using generalized maps. A detailed geotechnical investigation of the site including test pits, samples, and soil classification will be required.

SITE UTILITY LAYOUT AND DISTRIBUTION

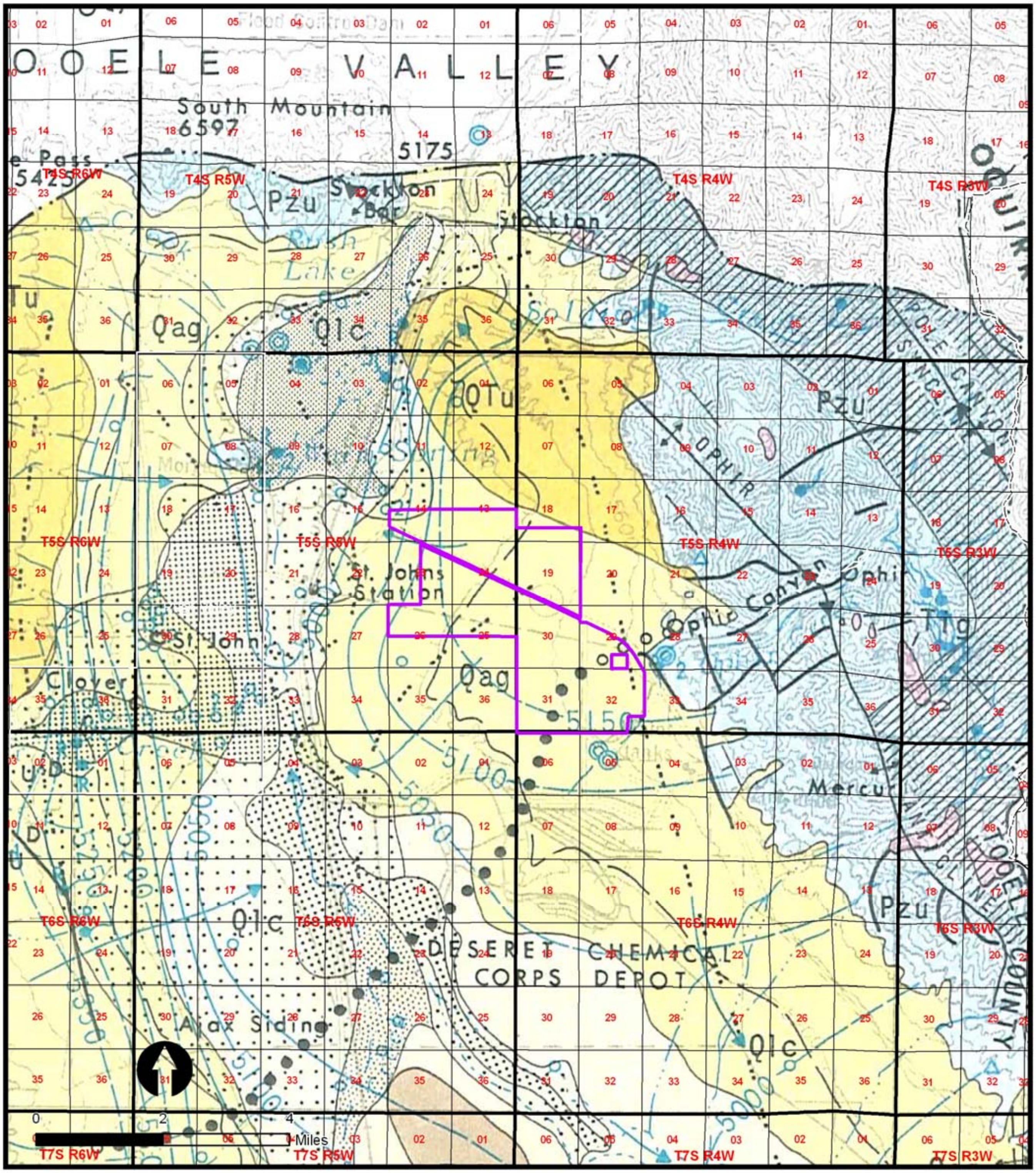
The following description was used in cost estimating and coordination of different proposed improvements.

CULINARY WATER

In order to bring potable water to the site, two wells are proposed east of the facility which would supply two storage tanks. These tanks will then deliver water to the site through a 12 inch main line water/ fire line. Once the line reaches the facility it would split and run toward the women’s and men’s portions of the prison. A 12 inch water/ fire loop will extend around the outer perimeter of both the women’s and men’s facilities. Water valves will be installed at approximately a 300 foot interval. Fire hydrants will be placed around the site. A 6 inch fire lateral and a 4 inch culinary lateral will extend from the loop to each building. Metering will be done at the well and tank location. Sizes are estimates only and may change as the design proceeds.

SANITARY SEWER

Estimated 6 inch sewer laterals are expected to sewer each building. These will run through individual sewage grinders before entering a sewer main line which will run to the north-west. Grease traps will also be installed on each building. The sewer for both the women’s and men’s portion of the prison will combine



Geologic Site Map

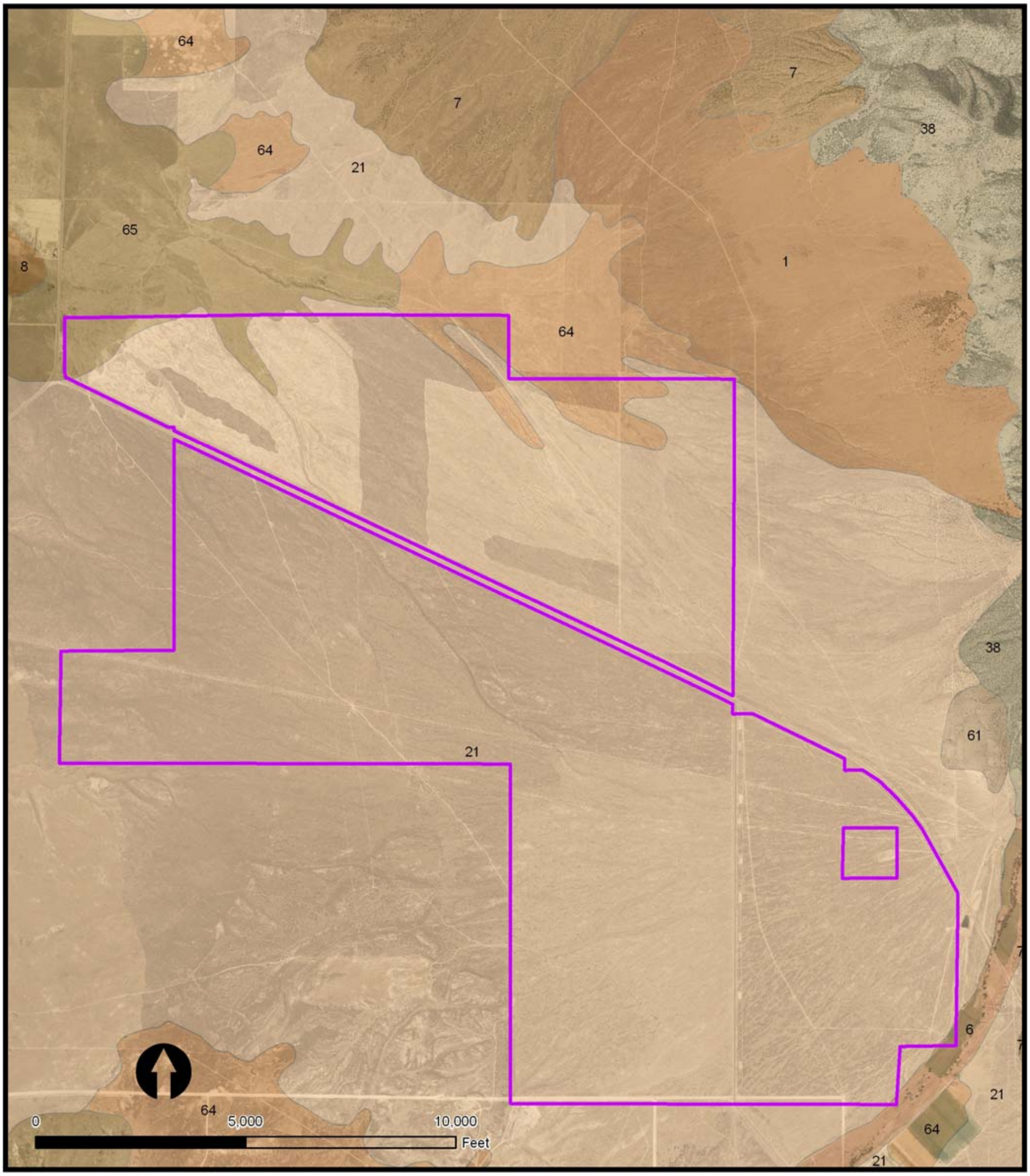
Prison Site Location Study - Rush Valley, Utah

Stantec Consulting Inc.
3995 S 700 E., Ste. 300
Salt Lake City, UT
84107-2540
Tel. 801.261.0090
Fax. 801.266.1671
www.stantec.com

QTu - Deposits and surfaces of uncertain age
QAg - Colluvium and alluvium
Pzu - Sedimentary Rocks
Qlc - Lakebed sediments

Notes:
USGS Geologic Map 1:100,000 scale

Figure 3.13 *Geologic Map*



NRCS Soils Map

Prison Site Location Study - Rush Valley, Utah

Stantec Consulting Inc.
3995 S 700 E, Ste. 300
Salt Lake City, UT
84107-2540
Tel. 801.261.0090
Fax. 801.266.1671
www.stantec.com

21 - Hiko Peak gravelly loam, 2 to 15 percent slopes
64 - Taylorsflat loam, 1 to 5 percent slopes
66 - Timpie silt loam, 0 to 3 percent slopes

Notes:
Soil Data - Natural Resources Conservation Service Map Survey # 611: Tooele County

Imagery - National Agricultural Imagery Program (NAIP) 2006, 1 m

Figure 3.14 *NRCS Soils Map*

approximately 1200 feet to the west and enter a new sewer treatment facility. This facility will consist of a treatment plant and a wastewater pond.

STORM DRAIN

Storm drain lines have been conceptually sized to handle a 10-year storm. Storm drain inlets will be placed around the site in order to direct surface runoff into the storm drain system in order to avoid ponding and surface erosion. 15 inch to 36 inch diameter pipes will carry storm water to the northwest and terminate in ponds west of the women’s and men’s portions of the prison. A 1.0 acre-foot detention pond will serve the women’s facilities and a 4.0 acre foot detention pond will serve the men’s facilities. The ponds will then be discharged in a manner so as not to cause erosion of the existing natural area to the north-west. This storm water will need to be kept separate from the treated waste water according to state regulations.

NATURAL GAS

An existing gas transmission line runs along the roadway corridor splitting the women’s and men’s facilities. A new 8 inch diameter main will connect to this transmission line and run to a new gas meter near the main entrance. After the meter this main will then be split and continue with 6 inch lines and run toward the women’s and men’s portions of the prison. The men’s facilities will have a 6 inch loop which will extend around the perimeter with laterals to each building. Isolation valves will be installed every 300 feet.

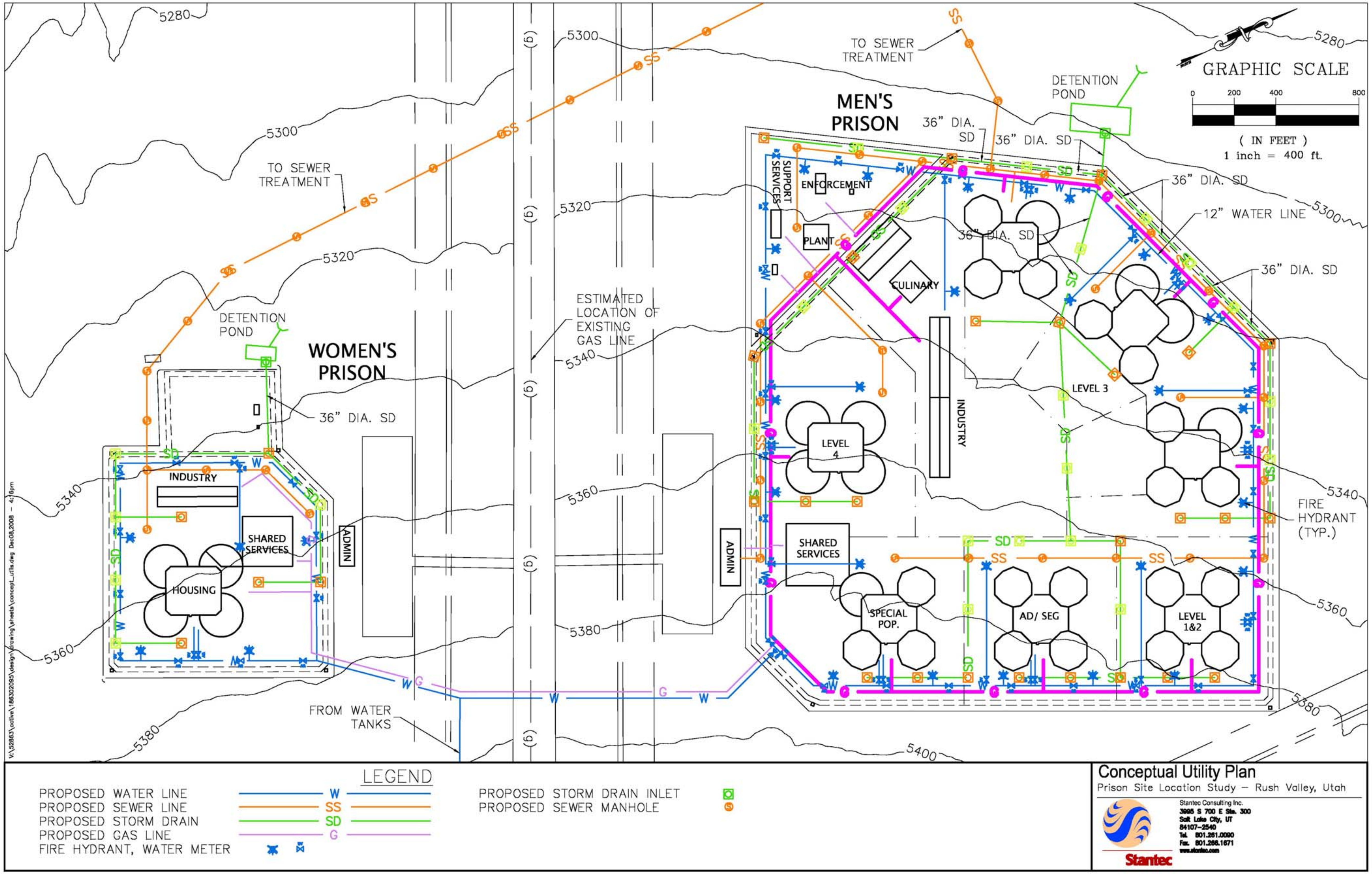


Figure 3.15 ***Conceptual Utility Plan***

SECTION IV: PRISON ELECTRICAL LOAD

NEW PRISON CAMPUS ELECTRICAL LOAD OVERVIEW

The current maximum demand load reported by Rocky Mountain Power at the Draper Prison site is in the 3.7 to 5 Mega Watt range (4,700-5,000 kW). Given the overall maximum expansion capacity of the new proposed prison site, we should anticipate from preliminary load analysis that the demand load for the new facility would be in the 10 to 15 Mega Watt range. There is a tremendous amount of variance potential in this estimate, given the current load status of the existing prison, how much energy is contributed geothermally, and what energy usage demands could change over the next 20 to 50 years. So, for the purpose of this study, a nominal demand load of 12 Mega Watts will be used in our comparative analysis.

EXISTING PRIMARY POWER AVAILABILITY

Spectrum Engineers conducted several interviews with representatives of PacifiCorp's Rocky Mountain Power regarding potential distribution service to a new prison facility located at the intersections of Utah State Routes 36 and 73 in Rush Valley, Utah.

Our first inquiry related to available transmission delivery voltages that existed in the area (either 46kV or 138kV). Rocky Mountain Power stated that at this time there is not a 138kV source anywhere close to this area. To determine what utility work would need to be implemented to provide 138kV service, the facility would require a feasibility study on the part of Rocky Mountain Power. Since the available voltage on the Primary Hi-Line really only affects line losses to the utility and the input primary voltage of the prison's substation transformers, it did not pose a major stumbling stone regarding a preliminary recommendation for substation design. If and when the project actually comes to fruition, a hi-line feasibility study on the part of Rocky Mountain Power would prove prudent.

As of today it appears that there is capacity on the existing 46kV system fed from the Tooele substation that would handle the initial on-line load of 3 to 5 Mega Watts. However, when the prison expands to its full capacity of 10,000 inmates, the Tooele substation and associated radial distribution system would require major upgrades. Rocky Mountain Power stated that a load of this magnitude would require upgrades to the overhead distribution lines as the line serving the intersections of Utah State Routes 36 and 73 is currently subject to significant voltage loss due to the distance from the Tooele substation. Rocky Mountain Power confirmed the distribution lines at the sub station would require some mitigation. A potential solution would be to install a load tap changer on the substation transformer or some type of voltage regulation at the prison's substation secondary taps.

For transmission delivery, and to receive the best utility rate possible, Rocky Mountain Power primary customers are required to build, own, maintain and operate their own substation. In addition, the customers are responsible for ALL the costs to bring the transmission line to their substation from its current available tap point. The proposed project site at the intersections of Utah State Routes 36 and 73 in Rush Valley, Utah is about 20 miles from Tooele. According to Rocky Mountain Power, the cost per mile of line for transmission line distribution construction is approximately $1.3 million per mile (a very rough estimate), and this does not included the expenses to secure rights-of-way. In urban areas, right-of-way easements could easily double the costs of line construction. Also, these numbers provided by Rocky Mountain Power are based on current 2008 construction costs and the Utility conceded these numbers could increase significantly in the next 10 years.

To provide distribution delivery at 12,470 volts, Rocky Mountain Power's nearest source is at Rush Valley, which is currently a very small substation. The Rush Valley substation is already very close to maximum capacity and a project of this magnitude would require its total reconstruction. The approximate distance from the Rush Valley substation to the proposed facility site is less than 3 miles, but no current three-phase line exists to the site. A totally new overhead line would need to be constructed to the proposed prison site at the intersections of Utah State Routes 36 and 73. The cost per mile for distribution line construction at 12,470 volts is approximately $350,000 per mile based on 2008 dollars and does not include costs to secure rights-of-way. An advantage to this scenario is that when power is delivered to the customer at the distribution service level (12,460 Volts), the Rocky Mountain Power Company would fund the line extension and upgrades up to a pre- negotiated allowed maximum with the Department of Corrections which is determined by taking 16 months of the monthly revenue the customer is expected to generate.

Rocky Mountain Power is currently in the process of determining site routing for new transmission lines at 138kV from Mona through Tooele County to provide an interconnect and supplemental with Rocky Mountain Power's Oquirrh substation located in West Jordan. Depending on the exact final site location and orientation, these new transmission level lines could foreseeably have a positive impact on the Department of Corrections long term plans for this proposed prison site. Rocky Mountain Power stated during an oral interview that this utility construction project is still pending the environmental impact study by the Bureau of Land Management (BLM) and a preferred route has yet to be determined.

Rocky Mountain Power also stated the utility has several plans for other significant system improvements over the next few years that may have a positive affect for the proposed project site. However, the utility would not discuss details of these plans stating their master plans are internal to the company and, until funded, could not be made public.

UTILITY PRIMARY POWER REDUNDANCY

Of major concern is the fact that once we achieve transmission level service to the proposed site, it will ONLY be a single three-phase radial feeder from one transmission line fed from a single substation. So the potential of a twin feed substation design with dual redundant utility primary feeders is not even on the table for consideration. Based on that assumption, which is founded in firm fact directly from Rocky Mountain Power, this preliminary study would recommend a single utility input feed to the substation with the prison's own integral co-generation station. The details and advantages of co-generation are addressed later in this study, but for the purpose of conceptualizing a substation design for estimating purposes, we will assume a single utility input with a synchronized co-generation power plant located near the campus physical plant and in close proximity to the prison's substation

A very rough estimate for the cost of a substation of this size is around $2 million.

CAMPUS SECONDARY SITE DISTRIBUTION

The recommended secondary site distribution from the substation throughout the prison campus should distribute at 15kV (12,460 volts) three-phase four wire. The secondary distribution should consist of a dual redundant loop, with each set of twin loop feeders sized to carry the maximum demand load of the entire facility. This token ring dual feeder concept would allow the maintenance staff to switch load connections between alternate feeders for repairs, and still leave the entire campus under full power capability feed from either direction on the loop. By providing a token ring dual redundant campus loop, any individual section of secondary distribution could be completely isolated for maintenance and servicing reasons with no loss of power.

The overall concept for the looped dual redundant secondary 15kV distribution system would be to feed the loops from the campus substation with twin duct banks, looped around the male site and interconnected across State Route 73 to the female campus, looping the female site. The twin duct banks would encircle each campus. Twin manholes would be placed at no more than 400-foot centers to facilitate conductor-pulling needs, and to accommodate any major changes in direction. The concept of the dual duct banks and manholes has huge merit because either redundant loop could be taken off line, with absolutely no interruption in power, and the off line conductors could be serviced in the manholes with no energized conductors in the manhole, a huge safety consideration.

At each major facility within both campuses, or loop tap point, this study would recommend installation of 15kV underground distribution switchgear. This style of low profile equipment would prove very beneficial to the overall security concept of the campus, as there would be a minimum profile for an escapee to hide behind.

The industry leader in this type of underground distribution switchgear is the S&C Corporation. Rocky Mountain Power utilizes S&C medium voltage distribution equipment exclusively because of its reliability, serviceability, and proven long-term industry track record of high performance.

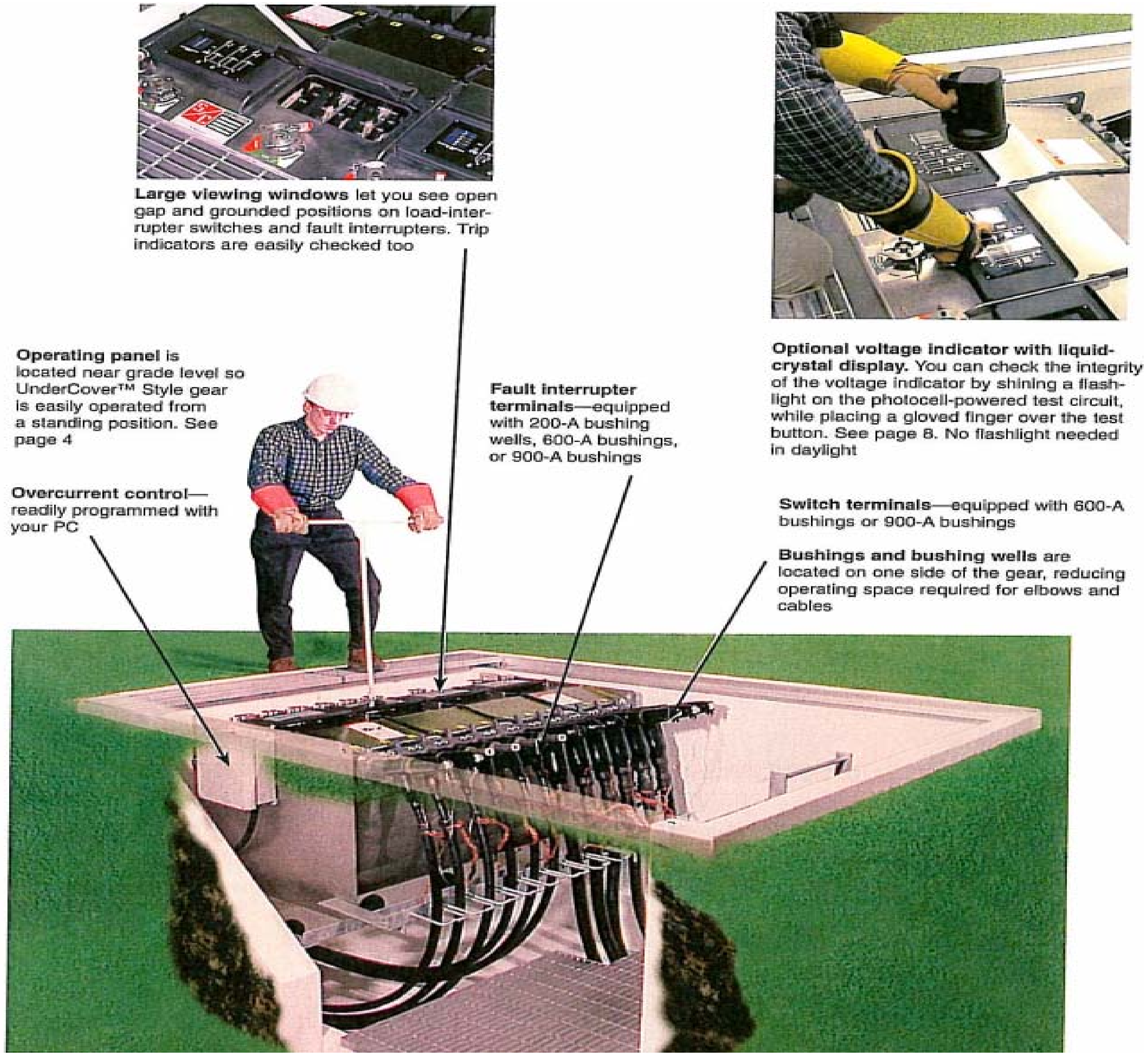
The low profile, pad mounted style, of this of switchgear is illustrated in figure 4.1.

S&C also manufactures a zero profile vault mounted style of 15kV switchgear that would be even more beneficial to the prison from a security standpoint because none of the equipment is above grade, leaving nowhere for an escapee to hide, see figure 4.2.

Figure 4.3 from S&C illustrates the at-grade servicing of a typical vault mounted underground distribution 15kV switchgear, with all the equipment underground.

Figure 4.2: *Typical S&C 15kV Vault Mounted Distribution Switchgear*

Figure 4.1: *Typical S&C Low Profile Pad Mounted 15kV Distribution Switchgear.*



Large viewing windows let you see open gap and grounded positions on load-interrupter switches and fault interrupters. Trip indicators are easily checked too

Optional voltage indicator with liquid-crystal display. You can check the integrity of the voltage indicator by shining a flashlight on the photocell-powered test circuit, while placing a gloved finger over the test button. See page 8. No flashlight needed in daylight

Operating panel is located near grade level so UnderCover™ Style gear is easily operated from a standing position. See page 4

Fault interrupter terminals—equipped with 200-A bushing wells, 600-A bushings, or 900-A bushings

Overcurrent control—readily programmed with your PC

Switch terminals—equipped with 600-A bushings or 900-A bushings

Bushings and bushing wells are located on one side of the gear, reducing operating space required for elbows and cables

Figure 4.3: *Typical Cross Section View of S&C Low Profile Pad Mounted 15kV Distribution Switchgear.*

Load interrupter switches in the vaults would provide three-pole simultaneous switching of the connected loads with no measurable loss of power downstream. The individual switches would have three positions (Open, Closed, and Grounded) and would provide a clearly visible “Gap” when opened to ensure safe serviceability.

Arc-spinning technology from S&C would be recommended for fault interruption to reduce the above grade profile of the vault mounted equipment by over 12” if the pad mounted units were chosen over the vault mounted units.

At each facility, the 15kv Distribution Switchgear would be load tapped with a radial facility feeder distributing 15kV power to the individual building transformer. Again the individual building transformers could be vault mounted to provide a clear view of the site, or the individual building electrical rooms could be designed with small unit substations inside the facilities to accommodate the interior installation of the transformers.

The 15kV secondary side distribution voltage would then be transformed at each building to 277/480 Volt building distribution voltages within the interior of each building.

A generator room would house an emergency standby generator within each facility to provide standby emergency power to each individual facility. The generator distribution and transferring scheme in each individual facility could be designed to allow and accommodate the generators synchronizing with the campus loop, and when operating in a power outage situation, actually back feeding the entire campus loop in harmony, much like the current configuration at Draper.

PERIMETER LIGHTING AND ILLUMINATION FOR ROADS AND FENCING

The ultimate goal in the design of lighting the perimeter fence and yard at any Correctional Facility is straightforward and simple: prevent escapes. Over the years, most Correctional Facilities have learned that inmates can be quite creative when plotting and carrying out a prison break.

The fences are the last obstacles prisoners would generally encounter during an escape attempt. Any lighting design should consider the alternatives required to provide the guards in the sites guard towers with as much light as possible without creating glare. The design should also want to help them distinguish colors so they could determine which inmates were involved in a potential escape.

State of the art prison site exterior site illumination techniques should employ 100-ft high-mast lighting systems installed along the perimeter fencing and also in the inmate-occupied yards. The fenced site at the proposed Rush Valley Institution is split into two large fenced areas, one for a eventual male population of approximately 8,500 inmates, and one for a separately fenced female population of 1,500 inmates. The combined sites cover an area of over 100 acres, with about 25% of that space currently programmed and devoted to yard. Inmates will have access to the yard area for recreation and exercise, with parts of the yard used as a sports field. Computer Aided Lighting Analysis (CALA) software should be employed during the actual design phase of the project to determine exact pole placement and how high the luminaires should be mounted and how they should be aimed. Current programming concepts would employ sixteen to twenty high-mast poles mounted throughout the yard areas with each pole utilizing ten to twelve 400-W metal halide luminaires mounted on each pole, depending on location and orientation. Yard poles would be spaced 350 to 370 ft apart, with light levels at 3-5 foot candles minimum maintained.

Yard areas should always be a concern from a security standpoint because the perimeter fence is located so far from the buildings. Any designed lighting system should have an ultimate goal of supplying enough light so guards can detect any movement in the yard, yet attempt to use as few poles as possible to avoid obstructing the guards' views. Each guard's limit of vision should be confined to looking across no more than 900 ft of space from the tower locations.

Perimeter fence illumination should be achieved with an appropriate number of high-mast poles mounted along the fence line with each pole utilizing 10 to 12 400-W metal halide luminaires mounted on each pole, depending on location and orientation. Ideally, these fence line poles would be located 6 to 10 feet outside the fence line and nominally be spaced 300 to 350 ft apart, with light levels in the 2-3 foot candle range minimum maintained.

Chase road illumination should be achieved with an appropriate number of high-mast poles mounted along the chase roads with each pole utilizing ten to twelve 400-W metal halide luminaires mounted on each pole, depending on location and orientation. Ideally, these chase road poles would be located 10 to 20 feet off the paved area and alternating on each side of the road. The chase road fixtures should nominally be spaced 300 to 400 ft apart, with light levels in the 2-3 foot candle range minimum maintained.

Figure 4.4: *Typical nighttime fence line illumination level of 2-3 foot candles.*

Whether in the yard or along the fence line or chase roads, luminaires should be aimed to achieve considerable overlap to eliminate dark spots in case a lamp or two burns out. The installed units should utilize differing beam patterns so the light is directed exactly where it is needed, throughout the yard and across portions of the roof where inmates may potentially gain access. Precise exterior site light control also prevents unwanted site illumination from infiltrating building interiors. All site luminaires should be controlled by a photocell and should be illuminated from dusk to dawn.

To facilitate ease of maintenance, each high-mast pole should be designed to include an internal winch and drive motor that lowers the luminaires to within 3 ft of the ground for ease of servicing and routine maintenance.

Utilization of a self-centering guiding tram will allow the lowering of units in winds up to 30 miles per hour. All moving latching components should be designed so they are mounted on the lowering ring so they may be serviced on the ground.

Figure 4.5: *Typical high mast fixture lowering device*

Maintenance protocols should mandate for the high-mast system site illumination fixtures to be group re-lamped to avoid burned out lamps and ensure maximum performance and illumination reliability.

GENERATOR SYSTEM OPTIONS FOR A COGENERATION PLANT

The next section of the study will address various options for power generation available for consideration in a proposed Main Campus Co-Generation Power Plant. This analysis will first analyze generation system options and potential fuel sources.

GAS-FIRED RECIPROCATING ENGINES

We begin our generator option discussions by considering the emergency power generation systems that the Department of Corrections currently utilizes at other facilities to generate emergency power in its existing prisons.

Direct hydrocarbon gas-fired (#2 diesel fuel) reciprocating engines utilized as the prime movers to drive generator sets are most commonly used for on-site electric generation in smaller commercial applications. These types of engines are more commonly known as internal combustion engines. They convert the energy contained in fossil fuels into mechanical energy, which rotates a piston driving a prime mover to generate electricity. Diesel-fired reciprocating engines typically generate from less than 5 kW, up to 7 megawatts (MW), meaning they can be used as a small-scale residential backup generator, or to a base load generator in industrial settings. Diesel-fired reciprocating engines offer efficiencies from 25 to 45 percent, and can also be used in a Combined Heat and Power (CHP) system to increase energy efficiency. Combined Heat and Power (CHP) applications will be detailed later in this study.

Research indicates the most efficient generation process using Gas-Fired Reciprocating Engines would be to utilize natural gas in a Combined Heat and Power (CHP) application, where the heat generated from the combustion process is captured and redirected for other uses. There are a large number of generator and fuel options available for consideration. Some of the commercially tested systems are by General Electric and Jenbacher. Product information on these units is provided for illustration in the Appendices of this report.

Figure 4.6: *Typical 3 to 5 megawatt range gas-fired Jenbacher reciprocating engine generator set.*

STEAM GENERATION UNITS

Natural gas can be used to generate electricity in a variety of ways. The most basic natural gas-fired electric generation consists of a steam generation unit, where fossil fuels are burned in a boiler to heat water and produce steam, which then turns a turbine to generate electricity. Natural gas may be used for this process, although these basic steam units are more typically a major utility utilizing large coal or nuclear generation facilities. These basic steam generation units have fairly low (poor) energy efficiency. Typically, only 33 to 35 percent of the thermal energy used to generate the steam is converted into electrical energy in these types of units. The feasibility of using a steam generation system in this case is doubtful; however, if steam generated at the prison's main physical plant were used to drive a prime mover, this option may be within the realm of possibility.

CENTRALIZED GAS TURBINES

Direct-fired industrial gas turbines or traditional internal combustion engines are also used as prime movers to generate electricity. In these types of applications, instead of heating steam to turn a turbine, hot gases from burning fossil fuels (particularly natural gas) are used to turn the turbine and subsequently generate electricity. Gas turbine and internal combustion engine plants are traditionally used primarily for handling peak-load demands. A major benefit of direct-fired units is the ability to quickly and easily turn them on. These types of plants have increased in popularity due to advances in technology and the availability of natural gas. However, they are still traditionally slightly less efficient than large steam-driven power plants.

COMBINED CYCLE UNITS

Many of the new natural gas-fired power plants are what are known as "Combined-Cycle" units. In these types of generating facilities, there is both a gas turbine and a steam unit, all in one. The gas turbine operates in much the same way as a normal gas turbine, using the hot gases released from burning natural gas to turn a turbine and generate electricity. In combined-cycle plants, the waste heat from the gas-turbine process is directed towards generating steam, which is then used to generate electricity much like a steam unit. Because of this efficient use of the heat energy released from the natural gas, combined-cycle plants are much more efficient than steam units or gas turbines alone. In fact, combined-plants can achieve thermal efficiencies of up to 50 to 60 percent.

DISTRIBUTED GENERATION

With distributed generation, turbines are located in close proximity to where the electricity will be consumed. Industrial turbines—producing electricity through the use of high temperature, high-pressure gas to turn a turbine (prime mover) that generates a current—are compact, lightweight, easily started, and relatively simple to operate. Distributed generation is commonly used by medium- and large- sized commercial establishments, such as universities, hospitals, large commercial buildings, and industrial plants. These systems are typically 21 to 40 percent efficient.

However, with distributed generation, the heat that would normally be lost as waste energy can easily be harnessed to perform other functions, such as powering a boiler or space heating. This is known as Combined Heat and Power (CHP) Systems. This option for a Central Campus Generation Plant seems to provide a viable and energy conscious alternative. Below is a discussion of the advantages of Combined Heat and Power (CHP) Systems followed by a discussion of the options of both direct-fire gas turbines and traditional combustion engines as the prime movers to turn our generators.

COMBINED HEAT AND POWER (CHP) SYSTEMS

Using energy efficiently has become a national goal across industries in the past decade. Driven by rising energy prices, an increasingly competitive marketplace, and environmental regulation of harmful pollutant emissions, commercial and industrial energy users are searching for the most efficient and cleanest energy sources. One innovation finding rapid and abundant commercial and industrial application is what is known as Combined Heat and Power (CHP) Systems. Essentially, this type of system recovers the waste heat from the burning of fossil fuels to generate electricity and applies it to power another process. For example, a basic Combined Heat and Power System might generate electricity through a large gas-fired turbine. The generation of this electricity would produce a great amount of waste heat. A Combined Heat and Power System might apply that waste heat to fire an industrial boiler instead of allowing this heat to escape into the atmosphere. In this way, more of the energy contained in the natural gas is used than with a simple gas turbine. This increases energy efficiency, which implies that less energy is needed to begin with (costing the user less), and fewer emissions are generated because a smaller amount of natural gas is used. Typically, a Combined Heat and Power System produces a given amount of electricity and usable heat with 10 to 30 percent less fuel than would be needed if the two functions were separate. A typical electric generation facility may achieve up to 45 percent efficiency in the generation process, but with the addition of a waste heat recovery unit, can achieve energy efficiencies in excess of 80 percent.

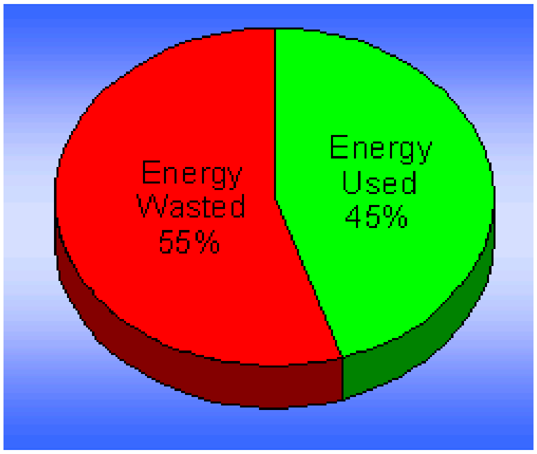


Figure 4.7: *Energy Efficiency in a Regular Electric Generation Facility*

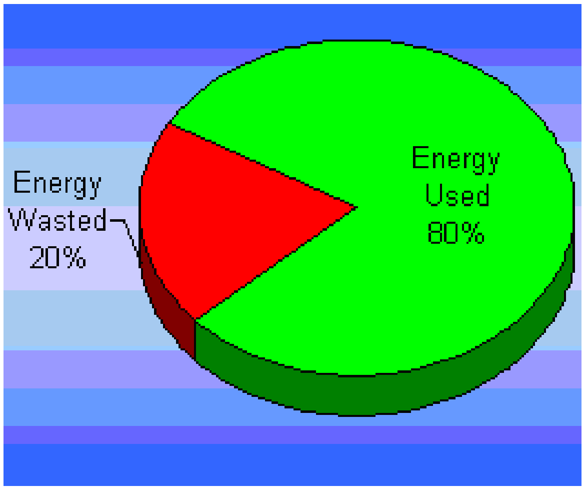


Figure 4.8: *Energy Efficiency in a Combined Heat and Power Generation*

Combined Heat and Power Systems (CHP) can be implemented to produce as much as 300 megawatts (MW) of electricity, to as little as 20 kilowatts (kW) of electricity, depending on the electrical and usable heat needs of the facility. It is not uncommon for larger cogeneration units to be installed in a facility that has very high space and water heating requirements, but lower electricity requirements. Under this scenario, the excess electricity is easily sold back to the local electric utility.

Types of Combined Heat and Power Systems

A typical (CHP) consists of an electric generator, which is driven by a gas turbine, steam turbine, or traditional combustion engine. In addition to this electric generator, a waste heat exchanger is installed with the generation package, which recovers the excess heat or waste exhaust gas from the electric generator to in turn generate steam or hot water.

There are two basic types of Combined Heat and Power Systems. The first is known as a “Topping Cycle System,” where the system generates electricity first, and the waste heat or exhaust is used in an alternate process, and the second is known as a “Bottoming Cycle System,” usually seen in industrial process plants and described below.

Four types of Topping Cycle Systems exist. The first, known as a “Combined-Cycle Topping System,” burns fossil fuel in a gas turbine or combustion engine to generate electricity. The exhaust from this turbine or engine can either provide usable heat, or go to a heat recovery system to generate steam, which then may drive a secondary steam turbine.

The second type of Topping Cycle System is known as a “Steam-Turbine Topping System.” This system direct burns fuel to generate steam, which then generates power through a steam turbine. The exhaust (left over steam) can be used as low-pressure process steam, to heat water for example.

The third type of Topping Cycle System, “Absorption Recovery Topping System,” consists of an electric generator in which the engine jacket cooling water (the water that absorbs the excess emitted heat from an internal combustion engine) is run through a heat recovery system to generate steam or hot water for space heating.

The fourth, and last type of Topping Cycle System, is known as a “Gas Turbine Topping System.” This system consists of a natural gas-fired turbine, which as the prime mover drives a generator that produces electricity. The exhaust gas flows through a heat recovery boiler, which can convert the exhaust energy into steam, or usable heat.

While Topping Cycle Systems are the most commonly used Combined Heat and Power Systems (CHP), there is another type of Combined Heat and Power System (CHP) known as “Bottoming Cycle Systems.” This type of system is the reverse of the above systems in that excess heat from a manufacturing process is used to generate steam, which then produces electricity.

These types of systems are common in industries that use very high temperature furnaces, such as the glass or metals industries. Excess energy from the industrial application is generated first, and then used to power an electric generator. If the capability to utilize excess or waste steam from the campus Physical Plant is an option, a “Bottoming Cycle System” may be worthy of additional evaluation.

In addition to these two types of systems, fuel cells may also be used in a Combined Heat and Power System (CHP). Fuel cells can produce electricity using natural gas, without combustion or burning of the gas. However, fuel cells also produce heat along with electricity. Although fuel cell Combined Heat and Power Systems (CHP) are still in their infancy, it is expected that these applications will increase as the technology develops. Natural Gas Fuel Cells will be additionally briefed in the following section.

Figure 4.9: *A Test Fuel Model Cell Cogeneration Plant at Miramar Naval Air Station*

Natural Gas Fuel Cells

Fuel cells powered by natural gas are an exciting and promising new technology for the clean and efficient generation of electricity. Fuel cells are still in development and are fast approaching commercial viability. Depending on when a new prison is built, they may well be the preferred solution for providing power to the prison. Fuel cells have the ability to generate electricity using electrochemical reactions as opposed to combustion of fossil fuels to generate electricity. Essentially, a fuel cell works by passing streams of fuel (usually hydrogen) and oxidants over electrodes that are separated by an electrolyte. This produces a chemical reaction that generates electricity without requiring the combustion of fuel, or the addition of heat as is common in the traditional generation of electricity. When pure hydrogen is used as fuel, and pure oxygen is used as the oxidant, the reaction that takes place within a fuel cell produces only water, heat, and electricity. In practice, fuel cells result in very low emission of harmful pollutants, and the generation of high-quality, reliable electricity. The use of natural gas-powered fuel cells has a number of benefits, including:

- ***Clean Electricity*** - Fuel cells provide the cleanest method of producing electricity from fossil fuels. While a pure hydrogen, pure oxygen fuel cell produces only water, electricity, and heat, fuel cells in practice emit only trace amounts of sulfur compounds, and very low levels of carbon dioxide. However, the carbon dioxide produced by fuel cell use is concentrated and can be readily recaptured, as opposed to being emitted into the atmosphere.

- ***Distributed Generation*** - Fuel cells can come in extremely compact sizes, allowing for their placement wherever electricity is needed. This includes residential, commercial, industrial, and even transportation settings.

- ***Dependability*** - Fuel cells are completely enclosed units, with no moving parts or complicated machinery. This translates into a dependable source of electricity, capable of operating for thousands of hours. In addition, they are very quiet and safe sources of electricity. Fuel cells also do not have electricity surges, meaning they can be used where a constant, dependable source of electricity is needed.

- ***Efficiency*** - Fuel cells convert the energy stored within fossil fuels into electricity much more efficiently than traditional generation of electricity using combustion. This means that less fuel is required to produce the same amount of electricity. The National Energy Technology Laboratory estimates that, used in combination with natural gas turbines, fuel cell generation facilities can be produced that will operate in the 1 to 20 Megawatt range at 70 percent efficiency, which is much higher than the efficiencies that can be reached by traditional generation methods within that output range.

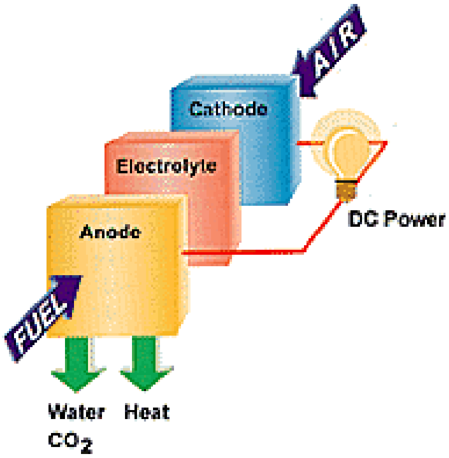


Figure 4.10: *How a Fuel Cell Works*
Source: DOE - Office of Fossil Energy

The generation of electricity has traditionally been a very polluting, inefficient process. However, with new fuel cell technology, the future of electricity generation is expected to change dramatically in the next ten to twenty years. Research and development into fuel cell technology is ongoing, to ensure that the technology is refined to a level where it is cost effective for all varieties of electric generation requirements.

While the concept of fuel cells has been around for more than 100 years, the first practical fuel cells were developed for the U.S. space program in the 1960s. The space program required an efficient, reliable, and compact energy source for the Gemini and Apollo spacecraft, and the fuel cell was a good fit. Today, NASA continues its reliance on fuel cells to power space shuttle vehicles. Because of technology improvements in recent years and significant investment by auto companies, utilities, NASA, and the military, fuel cells are now expected to have applications for distributed power generation within the next decade.

Figure 4.11: *A Typical 20kW Commercial Application Fuel Cell*
Photo Source: National Energy Technology Laboratory, Department of *Energy*

There are four primary fuel cell technologies. These include Phosphoric Acid Fuel Cells (PAFC), Molten Carbonate Fuel Cells (MCFC), Solid Oxide Fuel Cells (SOFC), and Proton Exchange Membrane Fuel Cells (PEMFC). The technologies are at varying states of development or commercialization. Fuel cell stacks utilize hydrogen and oxygen as the primary reactants. However, depending on the type of fuel processor and reformer used, fuel cells can use a number of fuel sources including gasoline, diesel, LNG, methane, methanol, and natural gas.

Natural gas (methane) is considered to be the most readily available and cleanest fuel (next to hydrogen) for distributed generation applications, so most research for stationary power systems is focused on converting natural gas into pure hydrogen fuel. This is particularly true for low-temperature fuel cells (PEMFC and PAFC). Here, fuel reformers use a catalytic reaction process to break the methane molecule and then separate hydrogen from carbon-based gases.

A fuel cell is similar to a battery in that an electrochemical reaction is used to create electric current. The charge carriers can be released through an external circuit via wire connections to anode and cathode plates of the battery or the fuel cell. The major difference between fuel cells and batteries is that batteries carry a limited supply of fuel internally as an electrolytic solution and solid materials (such as the lead acid battery that contains sulfuric acid and lead plates) or as solid dry reactants such as zinc carbon powders found in a flashlight battery. Fuel cells have similar reactions; however, the reactants are gases (hydrogen and oxygen) that are combined in a catalytic process. Since the gas reactants can be fed into the fuel cell and constantly replenished, the unit will never run down like a battery.

Fuel cells are named based on the type of electrolyte and materials used. The fuel cell electrolyte is sandwiched between a positive and a negative electrode. Because individual fuel cells produce low voltages, fuel cells are stacked together to generate the desired output for specified applications. The fuel cell stack is integrated into a fuel cell system with other components, including a fuel reformer, power electronics, and controls. Fuel cell systems convert chemical energy from fossil fuels directly into electricity. The image below shows the basic components of a generic fuel cell.

The fuel (hydrogen) enters the fuel cell, and this fuel is mixed with air, which causes the fuel to be oxidized. As the hydrogen enters the fuel cell, it is broken down into protons and electrons. In the case of PEMFC and PAFC fuel cells, positively charged ions move through the electrolyte across a voltage to produce electric power. The protons and electrons are then recombined with oxygen to make water, and as this water is removed, more protons are pulled through the electrolyte to continue driving the reaction and resulting in further power production. In the case of SOFC, it is not

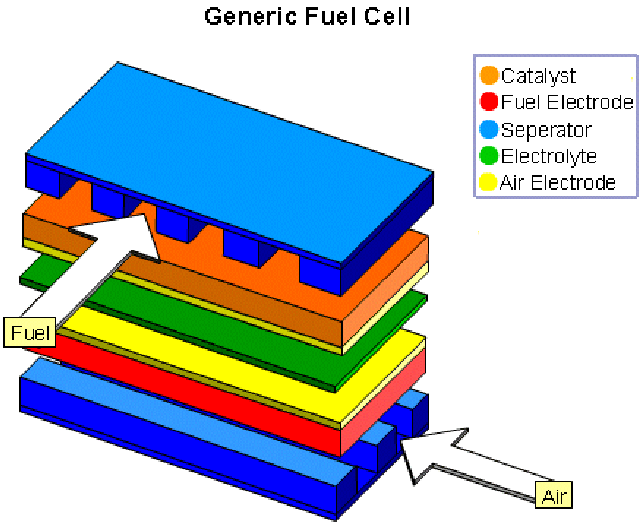


Figure 4.12: *A Typical Generic Fuel Cell*

Table 4.1: Fuel Cells Overview

	PAFC	SOFC	MCFC	PEMFC
Commercially Available	Yes	No	Yes	Yes
Size Range	100-200 kW	1 kW - 10 MW	250 kW - 10 MW	3-250 kW
Fuel	Natural gas, landfill gas, digester gas, propane	Natural gas, hydrogen, landfill gas, fuel oil	Natural gas, hydrogen	Natural gas, hydrogen, propane, diesel
Efficiency	36-42%	45-60%	45-55%	25-40%
Environmental	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions
Other Features	Co-Gen (hot water)	Co-Gen (hot water, LP or HP steam)	Co-Gen (hot water, LP or HP steam)	Co-Gen (80°C water)
Commercial Status	Some commercially available	Likely commercialization 2010	Some commercially available	Some commercially available

protons that move through the electrolyte, but oxygen radicals. In MCFC, carbon dioxide is required to combine with the oxygen and electrons to form carbonate ions, which are transmitted through the electrolyte.

Given that the commercial applicability of fuel cell technology is still in development, it does not appear to be a currently viable solution for the Department of Corrections needs. If, however, construction on the prison is delayed for 5 to 10 years, this technology may be fully developed and ready for utilization.

COMBINED HEAT AND POWER APPLICATIONS

Combined Heat and Power Systems (CHP) have applications both in large centralized power plants and in distributed generation settings. Cogeneration Systems have applications in centralized power plants, large industrial settings, large and medium sized commercial settings, and even smaller residential or commercial sites. The key determinant of whether or not combined heat and power technology would be of use is the nearby need or purpose for the captured waste heat. While electricity may be transferred reasonably efficiently across great distances, steam and hot water are not as transportable. Heat that is generated from cogeneration plants has many uses, the most common of which include industrial processes and space and water heating. Those facilities that require both electricity and high temperature steam are best suited for Combined Heat and Power Systems (CHP), as the system can operate at peak efficiency. There are many industries that require both electricity and steam, for example, the pulp and paper industry is a major user of Combined Heat and Power Systems (CHP). Electricity is required for lighting and operating machines, while the steam is useful in the manufacturing of paper.

Many commercial establishments also benefit from Combined Heat and Power Systems (CHP). Universities, hospitals, condominiums, and office buildings all require electricity for lighting and electronic devices. These facilities also have high space and water heating requirements, making cogeneration a logical choice. For example, the University of Florida has an on-campus 42 MW gas turbine cogeneration facility that produces electricity and space and water heating for the campus.

Gas Turbine Engine Electrical Generation (Over 500 kW)

Conventional Combustion Turbine (CT) generators are a very mature technology. They typically range in size from about 500 kW up to 25 MW for Industrial and Commercial applications, and up to approximately 250 MW for central power generation. They are fueled by natural gas, oil, or a combination of fuels ("dual fuel"). Modern single-cycle combustion turbine units typically have efficiencies in the range of 20 to 45% at full load. Efficiency is somewhat lower at less than full load.

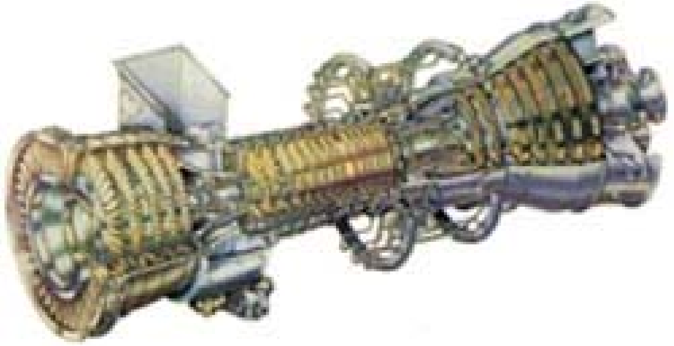


Figure 4.13*: A Typical Conventional Combustion Turbine Generator*
Photo Source: University of Florida

Table 4.2: Combustion Turbine Overview

Commercially Available	Yes
Size Range	500 kW - 25 MW
Fuel	Natural gas, liquid fuels
Efficiency	20-45% (primarily size dependent)
Environmental	Very low when controls are used
Other Features	Co-generation (gas or steam)
Commercial Status	Widely Available

There are three main components in a combustion turbine generator:

1. Compressor - incoming air is compressed to a high pressure.
2. Combustor - fuel is burned, producing high-pressure, high-velocity gas.
3. Turbine - energy is extracted from the high-pressure, high-velocity gas flowing from the combustion chamber.

Gas turbine systems operate in a manner similar to steam turbine systems except that combustion gases are used to turn the turbine blades instead of steam.

In addition to the electric generator, the prime mover turbine also drives a rotating compressor to pressurize the air, which is then mixed with either gas or liquid fuel in a combustion chamber. Increasing the compression raises the temperature, thereby achieving greater efficiency in a gas turbine. Exhaust gases are emitted into the atmosphere from the turbine or recovered for re-use in a Combined Heat and Power (CHP) System. Unlike a steam turbine system, gas turbine systems do not have boilers or a steam supply, condensers, or a waste heat disposal system. Therefore, capital costs are much lower for a gas turbine system than for a steam system. In electrical power applications, gas turbines are typically used for peaking duty, where rapid startup and short runs are needed. Most installed simple gas turbines with no controls have only a 20- to 30-percent efficiency, with the addition of Combined Heat and Power (CHP) Systems, efficiencies can increase in excess of 80% percent.

In addition, on-site natural gas turbines can be used in a combined cycle unit, as discussed above. Due to the advantages of these types of generation units, a great deal of research is being put into developing more efficient, advanced gas turbines for distributed generation.

Rolls Royce and General Electric are the leading manufactures of jet engines for aircraft. These two companies have also gone the furthest in the commercial development of turbine engines used as prime movers in electrical generation sets. This study will provide an analysis of the combined product research of these two recognized names in the development of the gas turbine generation. Product information from both manufacturers will be included in the Appendices of this report.

Gas Turbine Engine Noise

According to product data information available from General Electric, gas turbine generation systems can be extremely noisy. These turbines are comparable in noise level to aircraft jet engines, which are very noisy, even at idle speed. Stringent acoustical design rules must be followed wherever such systems are installed.

The noise level at any location within a power plant is the combined effect of noise radiated by all sources. Therefore, the noise from each individual source must be less than the overall plant requirement. In addition, the containment of the sound energy within a building results in a reverberant buildup of noise. The noise reflected from the interior building walls and other surfaces causes an increase in the noise level. General information and Acoustic terms regarding Turbine Generation is detailed in the Appendices Tab 12 document by GE entitled *"Acoustic Terms, Definitions and General Information."*

As an example cited in the GE *"Near-Field Noise Consideration Document,"* (reference Appendices) in order for the entire power plant to satisfy a required noise guarantee of no more than 85 dBA, it is necessary that each piece of equipment (including all turbine generator scope of supply equipment as well as the equipment supplied by others) that may be influenced by one or more of these factors, must radiate less than 85 dBA. If, for illustration, an adjacent system vacuum pump and the combustion turbine are located 2 meters apart, and if the vacuum pump radiates 80 dBA at 1 meter and the combustion turbine radiates 80 dBA at 1 meter, the resulting sound level from the two pieces of equipment is 83 dBA at a location 1 meter from both pieces of equipment. In addition, there will be noise from other equipment within the area. A 1-dBA allowance is included to account for the contribution from this other equipment. To account for the reverberant buildup effect of noise within a building with interior walls that are properly treated for acoustics, an additional 1-dBA allowance is also included. Therefore, these two pieces of equipment must be designed to a level of 80 dBA or less for the measured sound levels to meet the client's requirement of 85 dBA.

Beyond the worker exposure noise level requirements, consideration of noise pollution outside the facility is a major concern. If chosen as the preferred design solution, a Gas Turbine Generation Systems Facility will have to have stringent design considerations for both internal noise protections for workers, along with exceptional noise abatement and critical muffler systems to avoid noise pollution onto the campus outside the facility.

Gas Turbine Engine Emission Controls

The next issue to consider regarding selection of a Gas Turbine Generation Systems Facility is emissions controls. Reference Appendix X, which is GE's document entitled *"Gas Turbine Emissions and Control."* That document explains in great detail the design and operational considerations that must be in place when considering the Gas Turbine Generation System. These controls will affect both operation and maintenance costs.

Typical exhaust emissions from a stationary gas turbine are defined in two distinct categories. The major species Carbon Dioxide (CO2), Nitrogen (N2), Water Vapor (H2O), and Oxygen (O2) are present in significant percent concentrations. The minor species (or pollutants) such as Carbon Monoxide (CO), Unburned Hydrocarbons (UHC), Nitrous Oxide (NO), Nitrous Dioxide (NO2), Sulfur Dioxide (SO2), Sulfur Trioxide (SO3), and particulate matter smoke are present in parts per million concentrations. In general, given the specific fuel composition and machine operating conditions, the major species compositions can be calculated. The minor species, with the exception of total sulfur oxides, cannot. Characterization of the potential pollutants requires careful measurement and semi-theoretical analysis. The pollutants shown in “*Table 1”*of Appendices covering the *“GE Gas Turbine Emissions and Control*” document are a function of gas turbine operating conditions and fuel composition.

Plant layout is another significant concern in consideration of a Gas Turbine Generation Systems Facility. Major items that must be considered are as follows: (Please Reference Appendix X: *“Power Plant Layout and Planning*”)

Corrosive Emission Sources

What Corrosive chemicals, such as the following, are known or may be present?

- Coastal, within 12 miles of surf
- Heavy industrial
- Light industrial
- Agricultural with spray irrigation, frequent harvesting, soil preparation
- Dry salt lake nearby
- Desert
- Inland, rural
- Other

Local Emission Sources

List nearby (< 2 miles) potential sources of particulates:

- Coal piles
- Major highways
- Reclamation centers
- Mining operations
- Foundries
- Sawmills
- Wallboard manufacturing
- Agricultural activities
- Other

List nearby (< 2 miles) potential sources of liquid aerosols:

- Cooling water towers
- Spray irrigation systems
- Petrochemical processing
- Other

Weather

What are the monthly minimum, average, and maximum values for the following?

- Wind speed
- Wind direction (wind rose if available)
- Relative humidity
- Temperature
- Rainfall
- Snowfall
- Fogging conditions, number of days
- Icing conditions, number of days

Additional Emission Sources

List any additional emission sources not included above.

The above list identifies many issues that would need to be dealt with on the preferred site.

Gas Turbine Engine Maintenance and Training

Maintenance costs and availability are two of the most important concerns to a heavy-duty gas turbine equipment owner. Therefore, a well thought-out maintenance program that optimizes the owner’s costs and maximizes equipment availability should be instituted. For this maintenance program to be effective, owners should develop a general understanding of the relationship between the operating plans and priorities for the plant, the skill level of operating and maintenance personnel, and all equipment manufacturer’s recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting component life and proper operation of the equipment.

Ongoing operating and maintenance practices for GE heavy-duty gas turbines are extensively reviewed in Appendix X: *“Heavy-Duty Gas Turbine Operating and Maintenance Considerations*”, with emphasis placed on types of inspections plus operating factors that influence maintenance schedules. Regardless of the equipment selected, a well-planned maintenance program will result in maximum equipment availability and optimization of maintenance costs.

Given that gas turbine technology would be a new concept to the Department of Corrections maintenance personnel, a considerable amount of specialized training will have to occur to provide operation and maintenance teams with the necessary prerequisite skills to operate and maintain this technology. All of the manufacturers researched had extensive training programs available either on-site, or at the factories, and any gas fires turbine equipment specification written for procurement should absolutely include the requirements for extensive and adequate Corrections personnel training.

MICRO-GAS TURBINE ENGINE ELECTRICAL GENERATION (25 TO 500 KW)

Micro-turbines are scaled down versions of larger industrial gas turbines. As their name suggests, these generating units are very small, and typically have a relatively small electric output. These types of distributed generation systems have the capacity to produce from 25 to 500 kilowatts (kW) of electricity, and are best suited for residential or small-scale commercial development.

Figure 4.14: ***Gas Fired Micro-Turbine***
Source: Oak Ridge National Laboratory

Advantages to micro-turbines include a very compact size (about the same size as a refrigerator), a small number of moving parts, lightweight, low cost, and increased efficiency. Using new waste heat recovery techniques, micro-turbines can achieve energy efficiencies of up to 80 percent.

Micro-turbines were derived from turbocharger technologies found in large trucks or the turbines in aircraft auxiliary power units (APUs). Most micro-turbines are single-stage; radial flow devices with high rotating speeds of 90,000 to 120,000 revolutions per minute. However, a few manufacturers have developed alternative systems with multiple stages and/or lower rotation speeds.

At the end of 2006, micro-turbines were nearing commercial status availability. For example, a company called Capstone has delivered over 2,400 micro-turbines to customers (since 2003). However, many of the micro-turbine installations are still undergoing extensive field tests or for a large part, commercial large

Table 4.3: Micro-turbine Overview

Commercially Available	Yes (Limited)
Size Range	25 – 500 kW
Fuel	Natural gas, hydrogen, propane, diesel
Efficiency	20 – 30% (Recuperated)
Environmental	Low (< 9 – 50 ppm) NOx
Other Features	Cogeneration (50 – 80°C water)
Commercial Status	Small volume production, commercial prototypes now.

Figure 4.15: *Multiple 500 kW micro-turbines connected in a staged parallel arrangement*

scale test demonstrations. Our limited research into this developing technology of micro-turbines leaves it suspect to being a current viable alternative for the Department of Corrections.

Micro-turbine generators can be divided in two general classes:

- Recuperated micro-turbines, which recover the heat from the exhaust gas to boost the temperature of combustion and increase the efficiency, and
- Un-recuperated (or simple cycle) micro-turbines, which have lower efficiencies, but also lower capital costs.

While some early product introductions have featured un-recuperated designs, the bulk of developers' efforts are focused on recuperated systems. The recuperator recovers heat from the exhaust gas in order to boost the temperature of the air stream supplied to the combustor. Further exhaust heat recovery can be used in a cogeneration configuration. The figure below illustrates a recuperated micro-turbine system.

GENERATOR EQUIPMENT AND FUEL COMPARISONS

There are many advantages and disadvantages to different types of generation systems as illustrated previously in this report. Also, the fuel options available for use to fire an emergency generator vary in many operational aspects. Nearly all generators utilize gasoline, diesel, natural gas or propane for their operational needs. The generator system operation and fuel comparison chart illustrated on the following pages will identify operational and design concerns regarding application of different types of equipment and varying fuel sources. Some general features of the generator operation and maintenance itself influence final generator equipment and fuel option decisions. Where possible this comparison indicated specific generator hardware and environmental differences in generator set types and their operation along with a comparison to their fuel option choices.

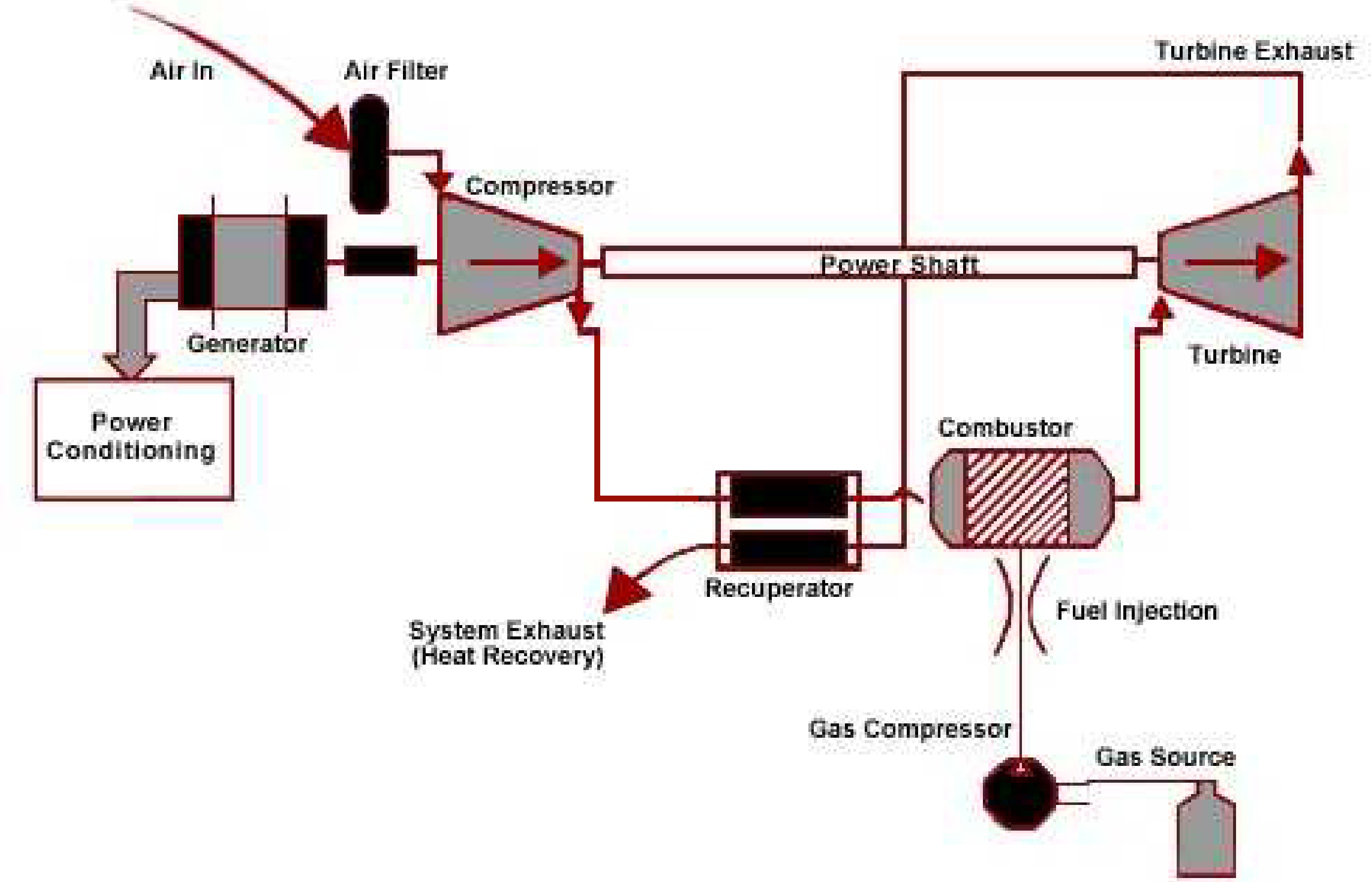


Figure 4.17: *Block Diagram of a recuperated micro-turbine system arrangement*

Table 4.4: Campus-wide Cogeneration Power System Equipment and Fuel Utilization Option Comparison Chart

This chart compares various types of systems that can be utilized for emergency power generation. This study shall compare the advantages of each type of system and compare advantages and disadvantages.

	Advantages	**Disadvantages**
Gasoline Fired Reciprocating Engines: <u>Manufacturers Considered:</u> Caterpillar Generac General Electric Kohler Onan/Cummins Detroit Diesel	Utilize readily available fuel sources - easily obtained. Proven Technology. Reliable. Clean burning fuel.	Highly flammable fuel sources. Short shelf life of fuel (12 months or less). Storing large quantities of fuel is hazardous. Refueling may be difficult during power outages. Somewhat expensive fuel. Inefficient. Low operating efficiencies in the 25 to 30% range.
Diesel Fired Reciprocating Engines: <u>Manufacturers Considered:</u> Caterpillar Generac General Electric Kohler Onan/Cummins Detroit Diesel	Least flammable fuel source. Fuel easily obtained *(fuel is easier to obtain during a disaster because it is a necessary fuel for the military, trucking industry, and farming operations).* On site fuel delivery available. Engine life for liquid-cooled 1800 RPM engines can approach 20,000 hours if properly serviced depending on the application and environment. High speed 3600 RPM diesel engines normally have a 10,000 to 15,000 hour life expectancy with proper maintenance and service under most conditions Less expensive to operate than gas engines. *The general rule of thumb for fuel consumption is 7% of the rated generator output (Example: 20 kW x 7% = 1.4 gallon per hour at full load).* Engines designed to work under a load for long periods of time and perform better when worked hard rather than operated under light loads. Can operate in sub-arctic conditions with fuel additive. Equipment is competitively priced for comparative sized water-cooled gaseous models with the same features. In high use situations overall long term cost of operation is much lower than gaseous GenSets. Fast start for stand-by generation options *(10 seconds or less).*	Fuel Source only has 18-24 month shelf life, without additives. Requirements for large storage tank systems increases cost of system. Delivery of fuel may not be available during long extended power outages. Total amount of diesel fuel storage must be considered relative to required run time in your geographical area. Engine noise much higher on a diesel GenSets compared to a gaseous engine. Use of a properly designed enclosure and sound attenuation system is more critical on a diesel engine system. Subject to "wet stacking" or over fueling if run for long periods of time with ultra light loads (less than 40% of the rated output). *"Wet Stacking" causes the engine to smoke and run rough because the injectors become carbonized. Running a heavy load will usually clean up the over-fuel condition and allow the engine to perform normally. Diesel engines operate better and are more fuel efficient when loaded (70-80% is optimum).* In sensitive emission areas in some states diesel engines are prohibited from operating over a prescribed number of hours per year to help reduce pollution levels. Requires clean moisture free fuel and a bit more maintenance than a comparable gaseous unit. Some cities and counties require the generator on-board fuel tanks to be double-wall containment type, which can increase the cost of the generator system. Equipment is typically heavier and requires more planning to load and unload than a lightweight gaseous GenSet. Operating efficiencies in the 20 to 45% range.

Table 4.4 continued: Campus-wide Cogeneration Power System Equipment and Fuel Utilization Option Comparison Chart

	Advantages	Disadvantages
Natural Gas Fired Turbine Generation: (w/LP Gas Backup) Manufacturers Considered: Caterpillar Generac General Electric Rolls Royce Onan/Cummins Detroit Diesel	Least flammable fuel source. Engines designed to work under a full load for long periods of time and perform better when worked hard rather than operated under light loads. Can operate in sub-arctic conditions with no fuel additive. In high use situations overall long term cost of operation is much lower than gaseous Reciprocating Engine GenSets. Proven mature technology with widely available equipment options. Unlimited fuel source - refueling not necessary. More convenient fuel source. Gas Turbines do not have a problem with "wet stacking" like diesels. *Natural gas is a mixture of hydrocarbons (mainly methane (CH4)) and is produced either from gas wells or in conjunction with crude oil production. Because of the gaseous nature of this fuel, it must be stored onboard a vehicle in either a compressed gaseous state (CNG) or more commonly as liquefied state (LNG).*	Large LP storage tanks required. Engine noise is much higher on a turbine compared to a gaseous engine. *(in excess of 120 dB when unattenuated). Use of a properly designed enclosure and worker protection along with extensive sound attenuation system is more critical on a turbine generation system.* Emission controls are an expensive consideration. Make-up and combustion air design considerations are complicated. Maintenance concerns are a new technology to the DOC and will require extensive training. Designed for continuous duty, not intended for short term standby considerations. Long start cycle *(much more than the 10 seconds required for stand by emergency generators in hospital applications).* New technology concept for the DOC. Natural Gas can become very dangerous if lines are broken. May be unavailable during natural disasters (earthquakes, etc) Lower power output (30% less BTU's per unit than gasoline). Fuel system plumbing results in higher installation cost. Natural Gas not available in many areas. Natural gas (NG) begins to de-rate at +20 degrees above zero. Initial generator cost is higher *(15 to 20% especially in sizes larger than 30 kW).* More expensive to operate by as much as 3-times the fuel consumption compared to diesels. Earthquakes can disrupt the flow of natural gas lines with up-rooted trees.
Micro Gas Fired Turbine Generation: Manufacturers Considered: Capstone	Compact Size (25-500kW) Small number of Moving Parts. Lightweight. Lower Costs in comparable size. Higher efficiencies, up to 45%. Low pollutant emissions.	Emerging Technology. Multiple units difficult to synchronize. Slow to start. *(In excess of 10 seconds).* In prototypical development. Limited Commercial availability. Requires extensive training for operation.
Natural Gas Fuel Cells: Manufacturers Considered: Fuel Cell Technologies	Easy to synchronize. Negligible Environmental Concerns. Up to 70% efficient. Completely Enclosed. No Moving Parts. Extremely Quiet. Does not generate surges.	Emerging Technology. In prototypical development. Limited Commercial availability. Requires generation of pure hydrogen as fuel. Currently very high costs commercially.

Table 4.4 continued: Campus-wide Cogeneration Power System Equipment and Fuel Utilization Option Comparison Chart

	Advantages	Disadvantages
Natural Gas with LP/Propane backup LP/Propane _(as an alternate backup fuel Option)_:* _*See propane notes below._	Long shelf life Clean burning Easily stored in large grade or underground tanks. Fuel Source easily obtainable during extended power outages. Quieter engine noise level. More emission compliant. Gaseous engines do not have a problem with "wet stacking" like diesels. Engine life for liquid-cooled 1800 RPM engines can approach 15,000 to 18,000 hours on industrial quality gaseous GenSets. Backup fuel source would be Available in large storage capacities at the proposed Physical Plant. Higher efficiency rate, 44% for natural gas versus 36% for comparable sized diesel. Cost of fuel less per million BTUH generated.	Pressurized cylinder of flammable gas. Fuel system is more complicated. Larger tanks are not aesthetically pleasing (unsightly). Fuel system plumbing results in higher installation cost. LP backup gas slightly more expensive fuel than natural gas, but still cheaper than diesel. Propane can become very dangerous if lines are broken. Propane begins to de-rate around -20 degrees below zero Fahrenheit. Initial cost of generator is extremely high compared to diesel. 25 to 50% in sizes under 100 kW. Equipment price doubles in sizes over 1 MW. Transient response time is slower than diesel. Longer start-time than diesel engines by comparison in size (10 plus seconds).
CHP – Combined Heat and Power Systems:	Works with any fuel source. Increases generation efficiency to in excess of 80%. Captures wasted heat normally expelled to atmosphere. Helps reduce engine noise levels. Helps emission compliance.	Increases first time Costs. Requires generation plant location in proximity to applicable use of reclaimed heat. Operational mechanical and plumbing systems for heat recovery results in higher installation cost. Initial cost of generator is somewhat higher, 10 to 20% to accommodate heat recovery needs.

Table 4.5: Summary of Fuel Factors

FACTOR	GASOLINE	DIESEL & MIXES	NATURAL GAS*	VAPOR PROPANE*	LIQUID PROPANE*
ENGINE COST	EXCELLENT (many low-cost GenSets on market)	VARIES (higher cost in small sizes)	VARIES (low cost in small sizes)	VARIES (low cost in small sizes)	VARIES (low cost in small sizes)
FUEL SYSTEM INSTALLATION & STORAGE COST	VARIES (low cost in small sizes)	VARIES (low cost in small sizes)	EXCELLENT (if gas service already available at site)	MEDIUM (if adequately sized tank already at site)	MEDIUM (if adequately sized tank already at site)
FIRE & PERSONNEL SAFETY	POOR (highly flammable, vapors poisonous)	EXCELLENT (high flash point)	MEDIUM (rare leak risk)	MEDIUM (rare leak or tank explosion risk)	MEDIUM (rare leak or tank explosion risk)
ENVIRONMENTAL IMPACTS	POOR (spill risk, exhaust not clean)	POOR (spill risk, exhaust not clean)	EXCELLENT (clean burning)	EXCELLENT (clean burning)	EXCELLENT (clean burning)
FUEL AVAILABILITY	MEDIUM (easy to purchase)	MEDIUM (must be delivered & stored)	EXCELLENT (storage not required, supply rarely lost)	MEDIUM (must be delivered & stored	MEDIUM (must be delivered & stored
COLD STARTING & OPERATION	POOR (forms gum deposits)	MEDIUM (hard starting at cold temperatures)	EXCELLENT	MEDIUM (tank must be large and full for vaporization)	EXCELLENT (no tank vaporization issue)
ENGINE LIFE/WEAR	POOR/ MEDIUM (depends on engine type)	EXCELLENT	MEDIUM	MEDIUM	MEDIUM

*See propane notes below.

Table: 4.6: Fuel Preference by Geography and General Use

Place	Use	Preference	Avoid or Reasons
Pacific Time Zone	Residential	Propane, Diesel	Avoid Natural Gas due to earthquakes
	Ranch	Diesel, Propane	
	Industrial	Diesel, Propane, NG	
Mountain Time Zone	Residential	Propane, Diesel	Propane preferred in mountain areas. Diesel preferred on ranches and farms for duel use.
	Ranch	Diesel, Propane	
	Industrial	Diesel, NG, Propane	
Central Time Zone	Residential	NG, Propane, Diesel	Natural Gas very dependable in these time zones
	Ranch	Diesel, Propane	
	Industrial	Diesel, NG, Propane	
Eastern Time Zone	Residential	NG, Propane, Diesel	
	Ranch	Diesel, Propane	
	Industrial	Diesel, NG, Propane	

Gaseous fuels such as natural gas, vapor propane and liquid propane are the most common choice for small automatic standby generators. Propane engines are economical to build and these fuels provide good starting reliability and are in common use. These fuels are available everywhere.

*A **vapor propane system** draws the fuel from the **top** of the tank usually through a pressure regulator at the tank. The liquid in the lower part of the tank must be able to absorb sufficient heat from the tank surroundings for vaporization to take place. Therefore, it is important that the tank has enough exposed surface area for this heat transfer. There can be a problem of insufficient fuel flow in very cold weather or if the tank is less than half full or is too small. In practice this only is an issue in the far northern areas of the USA.

*A **liquid propane system** draws the liquid from the **bottom** of the tank and small high-pressure tubing is used to carry it to the GenSet. The GenSet is then equipped with a special device to vaporize the fuel before combustion. This eliminates the low temperature vaporization concerns at the tank in cold climates. However it may complicate using propane for other appliances since it is being supplied in liquid form to the point of use.

Table 4.7: Six Classes of Fuel Oil

Name	Alias	Alias	Type	Chain Length
No. 1 fuel oil	No. 1 distillate	No. 1 diesel fuel	Distillate	9-16
No. 2 fuel oil	No. 2 distillate	**No. 2 diesel fuel or heating oil**	Distillate	10-20
No. 3 fuel oil	No. 3 distillate	No. 3 diesel fuel	Distillate	
No. 4 fuel oil	No. 4 distillate	No. 4 residual fuel oil	Distillate/Residual	12-70
No. 5 fuel oil	No. 5 residual fuel oil	Heavy fuel oil	Residual	12-70
No. 6 fuel oil	No. 6 residual fuel oil	Heavy fuel oil	Residual	20-70
Marine Classification for Fuel Oils				
MGO (Marine gas oil)	Roughly equivalent to No. 2 fuel oil, made from distillate only.			
MDO (Marine diesel oil)	A blend of gas oil and heavy fuel oil.			
LFO (Light fuel oil)	A blend of gas oil and heavy fuel oil with very little gas oil than marine diesel oil.			
IFO (Intermediate fuel oil)	A blend of gas oil and heavy fuel oil, with less gas oil than marine diesel oil.			
MFO (Medium fuel oil)	A blend of gas oil and heavy fuel oil, with less gas oil than intermediate fuel oil.			
HFO (Heavy fuel oil)	Pure or nearly pure residual oil, roughly equivalent to No. 6 fuel oil.			

Review of the above campus-wide Power System Co-Generation Equipment and fuel utilization option comparison chart condenses all pertinent evaluation factors regarding campus-wide generator selection into one concise tabular format for evaluation.

It is relatively easy to dismiss the Micro-Turbine and Fuel Cell technologies as viable options because of their high first time costs, limited availabilities, and the fact that they are still in developmental stages.

Gasoline Fired Reciprocating Engines, although a viable operational option, should be eliminated because of the fuel use, transport and handling issues, and because of the low operating efficiencies.

Natural Gas Fired Turbine Generation, with all its benefits should be strongly considered, if proper training and operational maintenance issues are adequately addressed.

By the process of elimination, this study's final recommendation option for generator selection is Diesel or LP/Natural Gas Fired Reciprocating Engines. The choice of Diesel Fired Reciprocating Engines should be a front line contender for selection for a large number of reasons. First, and most importantly, the technology is familiar to the Department of Corrections, as all its existing emergency power generation needs are of this type. Therefore, there would be no learning curve involved in adoption of this technology. In addition, Diesel Fired Reciprocating Engines are "fast start"—requiring less than 10 seconds to deliver emergency or cogeneration power. Going beyond these significant considerations, the choice of Diesel Fired Reciprocating Engines has a multitude of additional positive features. Diesel fuel used to fire the engine is one of the least flammable fuel sources, is simple to transport, and is easily obtainable, even in a long term emergency crisis (earthquake, for example) since the military, along with the trucking and agriculture industries depend on this fuel source. Generator life in a standby mode can be in excess of 15,000 operating hours when properly maintained, meaning a properly maintained generator can last up to 50 years. Being such a proven technology, most manufacturers will provide maintenance, parts and service on this type of equipment for many years into the future.

There are some disadvantages to this generation method. Diesel Fuel only has an 18 month shelf life. Also, a unit in the 5,000 kW range, at full load will consume in excess of 200 gallons of fuel per hour, requiring huge storage tanks, especially if the unit is intended for peak shaving. Beyond those negative considerations is high engine noise, potential for "Wet Stacking" and related emission considerations.

These negative diesel fuel-related issues make the consideration of an LP/Natural Gas Fired Generator a very worthy option. Natural gas burns much cleaner than diesel, and has minimal environmental impacts. LP/natural gas units tend to be slightly more efficient (44% for Natural Gas versus 36% for Diesel) with lower fuel consumption costs, and longer engine life of up to 18,000 standby hours of operation before a major overhaul (Life expectancy of over 50 years). The only major drawback to Natural Gas Generators in the 3 to 5 MW range is the much higher first-time cost than a diesel unit (as much as two to three times the equipment cost for a comparable size diesel unit). The final decision on fuel sources is the discretion of the Department of Corrections, however, considering all the options discussed, from an engineering and operational standpoint, this study would recommend strong consideration of a duel fuel Gas Fired Reciprocating Engine Generator Set utilizing natural gas as the primary fuel source with the capability of burning LP gas or #2 Diesel as the reserve alternate fuel source.

SITE LOCATION FOR CAMPUS GENERATION PLANT

First, a 5 to 15 MW Campus Generation Plant will be extremely noisy (in excess of 85 dBA), even with proper sound attenuation and critical silencers. The plant should not be placed in the heart of the central campus for that reason. Location of fuel storage is another major concern. This study recommends the use of natural gas as the primary fuel source with LP gas or #2 Diesel as backup to fuel the new generator plant. Since LP Gas appears to be available in abundance at the chosen site, a back-up fuel storage facility near the Physical Plant, and in close proximity to the sub-station, is a viable option. This arrangement is also attractive and ideally situated for the co-generation plant location since we intend to recover the waste heat in a Combined Heat and Power Application from the generation process in the form of 15-Pound steam that will need to be piped back into the Physical Plant. Lastly, from an electrical standpoint, the most straightforward electrical connection to the campus loop would lie in proximity to the new sub-station, where we could utilize in-place infrastructure to intercept the proposed connection to the campus 15 kV primary electrical distribution system.

If diesel engines are chosen as the design solution for capital cost savings, the substation location for the new generation plant is still the only logical choice for the reasons previously listed. Additionally, there is insufficient room in the heart of the central campus to install the underground diesel fuel tank.

COST AND EQUIPMENT OPTIONS FOR THE NEW CAMPUS COGENERATION FACILITY

Table 4.8 illustrates approximate incremental costs associated with the installation of a Campus-Wide Co-Generation System. This listing could be used as a “Kit-of-Parts” budgetary shopping list to commit to a particular design configuration or solution that falls within available funding and/or budgetary considerations or can be utilized for modeling future construction funding appropriations.

Table 4.8: Incremental Campus Cogeneration System Construction/Procurement Costs

Equipment or Work Item	Median Cost	$/kW
Caterpillar 2.5MW Diesel Generator Set	$680,000	$272
Caterpillar 3.0MW Diesel Generator Set	$850,000	$283
Caterpillar 5.0MW Diesel Generator Set	$2,000,000	$400
Caterpillar 2.0MW NG Generator Set	$1,200,000	$600
Caterpillar 3.0MW NG Generator Set	$2,200,000	$733
Caterpillar 5.0MW NG Generator Set	$6,000,000	$1200
GE 2.5MW Diesel Generator Set	$750,000	$300
GE 3.0MW Diesel Generator Set	$900,000	$300
GE 5.0MW Diesel Generator Set	$1,800,000	$360
GE 2.5MW NG Generator Set	$1,300,000	$650
GE 3.0MW NG Generator Set	$1,750,000	$583
GE 5.0MW NG Generator Set	$4,500,000	$900
Cost of 4000 SQFT Generator Metal Building	$800,000	
Brick Façade for Generator Building	$300,000	
Heat Recovery Equipment (Per Unit)	$250,000	
Steam Tunnel and Lines to Physical Plant	$600,000	
Natural Gas Lines	$200,000	
Electrical Connections to Physical Plant	$350,000	
Synchronizing Switchgear	$500,000	
Cost for a 30,000 Gal Diesel UG Storage Tank	$400,000	

COGENERATION CONCLUSIONS

The results of this study clearly indicate the application of a campus-wide Co-Generation System will provide operational benefits to the Department of Corrections in operational efficiencies and system reliability and redundancy, especially since Rocky Mountain Power can only currently support one main substation feeder to the entire site. Most importantly, adding a second level of redundant power to the entire campus radial 15 kV distribution loop would help mitigate the potential of an overall campus outage in the event on a power outage.

Furthermore, the application of this campus-wide Co-Generation System could also provide the added benefit of peak shaving of high utility demand charges in the summer months. It also holds the potential for cogeneration applications in the future, or even potentially making the site self sufficient in the event of a catastrophe.

Turbine technology is the most costly system proposed, and has a number of complications (slow start, high noise, emissions, maintenance, and training on a new technology). However, is a worthy candidate for consideration.

Fuel cell technology looks extremely promising; however, it is still an emerging technology and, as such is risky and expensive. This development of this technology should be followed closely because it may become commercially viable in the near future.

Micro turbine technology looked extremely promising, but given the loads of our system needs, it would require synchronization of well over 20 units that would be next to impossible to synchronize and coordinate with available commercial synchronization technology.

Generation of electricity using a Combined Heat and Power (CHP) System that generates campus-wide electricity through a large diesel or natural gas-fired generator set would produce a great amount of waste heat. A CHP System could be designed to apply that waste heat into firing an industrial boiler instead of allowing this heat to escape into the atmosphere. In this way, more of the energy contained in the diesel fuel or natural gas is used than with a simple internal combustion engine. This greatly increases energy efficiency, which implies that less energy is needed to begin with (costing the Department of Corrections less in long term operational costs), and fewer emissions are generated because a smaller amount of diesel fuel or natural gas is used. Research indicates a typical Electric Generation Facility may achieve up to 45 percent efficiency in the generation process, but with the addition of a waste heat recovery unit, can achieve energy efficiencies in excess of 80 percent.

The technology, operation and system reliability of traditional direct diesel or gas-fired reciprocating engines utilized as the prime movers to drive generator sets are currently utilized for electric generation at other DOC Complexes. Because of this, and the fact that these engines' operation costs and maintenance needs are not a variable from the Corrections perspective, recommendation of this comfort level of operation and accepted technology needs no further discussion. This Study's recommendation is to proceed with known technology and pursue a Campus Wide Co-Generation Distribution System utilizing gas-fired internal combustion engines. The final decision of whether to fire these engines with diesel fuel or natural gas will be determined by the ability to fund the first-time capital equipment costs.

CO-GENERATION PLANT DESIGN RECOMMENDATIONS

The maximum peak demand load the Draper Campus has ever experienced based on the information provided by the local utility and the Department of Corrections has been in the 5 megawatt range. The most operationally effective design of the Campus Emergency Distribution Generation System would utilize LP/natural gas internal combustion engines driving up to three emergency generators, providing a staged power input capacity operating in a Combined Heat and Power System designed to recover heat generated during the combustion process of the generator. Exact generator sizing, and final specific generation plant locations are decisions that should be made during the actual schematic design process of the generation plant, but this study would recommend consideration of a base plant design that would locate a new Co-Generation Distribution System Building in the general vicinity of the Campus substation. This proximity to the substation and the campus physical plant would make the electrical interconnection to the campus 15 kV distribution system relatively straightforward. In addition, the close proximity would keep construction costs to a reasonable level for a few reasons. First, the lines carrying steam generated in the combustion process back to the physical plant for re-use would be shorter. Second, natural gas lines at the physical plant could be tapped to service the boilers. Third, the LP or diesel storage facility could be used as the back-up fuel source.

However, with a differential in base system equipment costs of up to 300%, between diesel and natural gas engines, many of the operational efficiencies of natural gas over diesel may be overridden by the huge first-time capital equipment cost savings realized by diesel generator engines.

Available equipment sizing varies from manufacturer to manufacturer, but in general, the initial base plant should be designed to accommodate up to three generators in the 5 to 10 megawatt range to handle the initial demand load, have expansion capabilities for the future, and, most importantly, allow two generators to handle the baseline (and future) campus load while a third generator is off line for maintenance. The plant should then be designed to accommodate expansion for the future addition of at least two more generation units of equal capacity for future growth and facility expansion.

Cost of the base generator system equipment itself represents the largest incremental capital expenditure and would range in the $270 to $400 range per kilowatt generated for diesel equipment (between 1.3 and 4.0 million dollars per generator, depending on selected generator manufacturer, equipment sizes and installation configurations), and in the $600 to $1200 range for natural gas equipment (between 3.0 and 8.0 million dollars per generator, depending on selected generator manufacturer, equipment sizes and installation configurations). The facility required to house the generator plant and supporting building infrastructure would cost in the $750,000 to $1,000,000 range, and the mechanical infrastructure and equipment to capture the waste heat and return that 15 Pound Steam to the physical plant would be in the $1,000,000 to $1,500,000 range. If the natural gas option is chosen, cost to get the adequate supply of LP/natural gas to the generators is contingent on the exact final location of the generation plant, and the closest available high-pressure natural gas line and proximity to the onsite LP/diesel storage tanks. Details of specific generator equipment design and package specification are all issues that should be further studied and developed once final decisions are made regarding equipment type, fuel firing methods, waste heat reutilization needs, final site location, and currently available or future funding.

PHONE – DATA AND COMMUNICATIONS (TO THE SITE)

Telecommunications circuits required by the combined men's and women's facilities has been estimated at approximately 4000 Mb/s (ten each T-5 circuits) as per the "Prison Site Location Study" RFP dated October 24, 2007. Traditionally, T-carrier circuits have been delivered using multi-pair copper UTP cabling (Unshielded Twisted Pair). However, T-carrier technologies using copper UTP cabling have given way to the use of optical cable trunks as evidenced by the fact that fiber has already been laid along Highway 73 and the access road to the Chemical Depot providing close access from the prison site to a telecommunication services provider. Cost of delivery to the site would entail a prison-provided ductbank connection from the prison site's demarcation facility (most likely the Administration Building) to the utility provider's nearest manhole.

With the utility services already in place in the form of optical fiber, this particular prison site is already in line to have provided to it a veritable future proof resource of communication services. A single OC-48 network line (2 fiber strands), the mostly commonly deployed, has transmission speeds up to 2488 Megabits/sec (2.4 Gigabit/sec) or more than twice than half the capacity of the ten T-5 carriers. A single 48 strand single-mode cable is approximately 0.5 inches in diameter and carries more than seven times the same transfer rate as the ten T-5 carriers. As the demand for wide area telecommunication circuits are driven by the wireless technologies moving from 3G to NextG for Internet, data, and media services, the recent installation of optical carriers adjacent to the site has the prison facilities already covered.

As suggested in the RFP, microwave communications may also be an alternative to delivering high transfer rates of telecommunications. This is certainly available in the greater Salt Lake area, but the technology lends itself to more remote applications where cross country trenching is so much more cost prohibitive because of distance. Since optical carriers have already been installed in close proximity to the site, exploring the alternative of microwave services is unnecessary. Even in an equal cost comparison, a direct hard line connection will always be preferred over a wireless connection.

Currently, OC carriers are considered a SONET technology (Synchronous Optical Network) that is used worldwide for delivering primarily voice and data communications. The horizon however sees 100 Gigabit Ethernet as an emerging delivery method. Ethernet is an asynchronous technology with direct protocol comparisons to the IP (Internet Protocol) world we live in. Several methods of data delivery have come and gone over the past 35 years – including Token ring, Ethernet, ATM, Frame Relay, X.25, SONET, ISDN, etc. But as the ways of packaging data have evolved, Ethernet has maintained its position and has proved to be the most solid and adaptable of delivery methods. That being said, whether the next five to ten years move towards higher Ethernet transfer rates or stays with synchronous transfer rates, like the current OC carriers, the media of choice will be fiber.

PHONE – DATA AND COMMUNICATIONS (AT THE SITE)

Delivery of phone and data communications, as well as other low voltage systems' communications, to all sectors of the prison site is best done using "rings" or circulating duct banks that encircle the facility. The intent of the "ring" theory is that the duct bank pathways are continuous with no dead-ends. This provides a natural means of redundancy and reliability by employing "self healing" technologies, with backbone cabling going in both directions, such that it precludes any full scale shutdown of any of the low voltage communications and services. A breach at any point on the "ring" calls into action the need for the electronics to send information over the other remaining circuit paths.

Communication needs for the duct bank include any and all systems that utilize any kind of network communication between panels and/or servers, whether it is standard Ethernet or not. An ever expanding list includes the following: Telephone circuits, facility intercom and mass notification circuits, computer/data circuits (LAN), Fire Alarm communications, BMS (Building Management Systems) communications, Security systems including video surveillance, gate controls, fence protection, and radio connections. In addition to these services other needs for TV, media, entertainment, and educational content to be delivered on site should also be included. Each of these systems will employ potentially different cable types and requirements for "repeating" signals over large distances. A singular type of media for all systems, such as fiber, makes sense but may not be possible depending on the availability of equipment that can "translate" from one signal or communication type to a common mode of delivery allowing all system circuits to be transported over fiber. Taking advantage of the increased distance afforded by fiber between "repeats" however, makes for a cleaner and more manageable systems' effort by having less connection locations to keep track of.

It is preferred that this communications duct bank be installed outside the perimeter fence and that it encircles the entire facility. A minimum of 12 each 4 inch conduits, encased in concrete, should be considered for the men's facility and a minimum of 8 each 4 inch conduits, also encased in concrete, for the women's facility. This duct bank will be interrupted periodically with underground vaults for pulling and branch exit requirements. The RFP suggested a 300 foot separation between these vaults. As has been learned in the past, these vaults do not always remain dry and are subject to filling with water. For this purpose, each vault will have an above ground enclosure provided for any and all splicing, terminations, etc. that might be needed at the vault location. Depending on the location of the vault, such as at the far sides of the site perimeter where no terminations or splicing may be required due to the use of longer distance media types, the vaults may be spaced at greater distances than 300 feet and may also not require the above ground enclosures.

The proposed site layout for the men's prison site is approximately 10,000 feet of perimeter assuming the duct banks will be 20 to 30 feet out away from the perimeter fence. This computes to roughly 30 vaults to be installed as part of the communications duct bank. The main communications connect "facility" should either be located inside the Administration building or located in a separate smaller building adjacent to the Administration building. The duct bank will directly intersect with this main connect facility, limiting the number of bends in the conduit pathway. The proposed site layout for the women's prison site is approximately 5,000 feet and translates into roughly 16 vaults with enclosures. Again, the main connect facility will intersect this duct bank. A separate duct bank of a minimum of 6 each 4 inch conduits for communications and systems' requirements only will need to be installed between the two main connect facilities at the men's and women's prison sites.

SECURITY SYSTEMS PERIMETER FENCE

The perimeter fence construction should follow established standards found in UDC Construction documents, which takes the form of two lines of fence, inside and outside, each topped with razor ribbon, and separated by 25 to 30 feet of open rock filled space. Concrete foundations under the fence lines secure the fabric to the ground.

There are presently several types of fence protection systems being used in other states and being further developed. Most of the different fence protection products can be categorized into three main groups. The "shake and rattle" group uses sensor cable of either copper or fiber optics to detect when the sensor cable is physically moved. For this purpose, the sensor cable is generally affixed directly to the fence fabric. Variations include the use of fiber optic cables that usually require more installation and maintenance time as they are most often installed as a "mesh" to cover more of the fence fabric. Fiber terminations and connections also require special tools and skills. Other fence protection methods in this group include taut wire installations. These usually become a third fence line as the wire is stretched between isolators held off of the actual fence or are placed on their own row of fence posts. The second group or category uses motion to set off detectors. Pairs of microwave transmitters and receivers are located such that any disturbance between the two microwave heads is registered as an alarm. This includes most anything that gets in the way, such as weeds, paper, animals, etc. The third group uses "volume" to detect an intrusion into the space. Examples of this group include electromagnetic fields, electrostatic fields, and magnetic anomaly detection fields. The magnetic anomaly detection product is essentially a metal detector looking for any kind of conductive metal. This works well keeping weeds, paper, and animals from causing an alarm, but could also be compromised by a person with no metal as well. The electrostatic field is generated by above ground wires, much like the taut wire product, on their own fence posts or insulators. The electromagnetic field probably works the best in this group as it is a buried set of cables that are looking for any kind of conductive material or mass moving through its field, not just metal. It gives no pre-warning of its presence by not being seen, but can become unreliable due to ground temperature and moisture changes and inaccurate depth installation problems. Non lethal electric fences need the same kind of installation – separate fence rows- as the taut wire and electrostatic field sensors.

The current combination used by the UDC has functioned well and has been consistently maintained to where the technical crews are now considered "experts" on these two systems. Both the sensor wire fence protection system and the microwave motion detection system are used in tandem as the state's perimeter fence protection. The inherent weaknesses of both systems are mitigated by new DSP filtering and comparisons in the new electronics to get higher detection capabilities with lower nuisance alarms. Once the systems have been installed correctly and any problems created by bad fence construction (loose fabric, insufficient post support, etc) are fixed, the continued maintenance is fairly simple – keeping the trash and weeds cleaned up and sensor cable affixed to the fence fabric.

Staying with the current fence protection system standards established by the UDC will maintain a high level of security. None of the other fence protection products would provide higher detection levels. Furthermore, the other products would be more costly to install and would have higher maintenance requirements.

SECURITY SYSTEMS PERIMETER CAMERAS

Placement of perimeter and site cameras should be defined in terms of being a supplement to actual visual line of site by officers. Perimeter cameras should be deployed as both fixed and pan/tilt/zoom (PTZ) types. Fixed cameras should be used at locations where a fairly constant view is needed and is usually aimed at specific objects such as gates, docks, and entrances. PTZ cameras should be placed to cover a lot of ground, not just specific objects. All camera images should be recorded digitally 24/7 or programmed for motion detection recording. Individual digital video recorders (DVR's) with TCP/IP (Ethernet) capability for both remote control and/or viewing shall be required. New technologies that record camera images directly to network hard drives should also be considered. Video surveillance for the site perimeter, facilities, and gates should be partitioned from other interior site camera locations to limit the number of cameras the officers in the towers are directly concerned with. With too much to watch, nothing gets seen.

For the proposed men's prison site, it is estimated that there should be a minimum of 4 PTZ and 4 fixed cameras on the perimeter fence and an additional 3 PTZ cameras covering the interior grounds, with 3 fixed cameras for the exercise yards. For the proposed women's prison site, it is estimated that there should be a minimum of 3 PTZ cameras and 2 fixed cameras on the perimeter fence. Interior grounds should be able to be seen by the perimeter PTZ cameras.

PERIMETER GATE CONTROLS AND TOWERS

Guard towers should be located at every other change in fence direction. A tower officer should have a clear visual view of two perimeter fence rows, one to his left and one to his right. Any extended distances should be supplemented with fixed cameras. There should be two towers with view of the site perimeter entrance gates. This provides a redundancy of both visual and electronic control of the gates, with both towers having potential control of the gates. Thus complete control of the gates cannot be overtaken by the surrender of a single tower. The towers should be fashioned after those used at CUCF.

In addition to the two towers with gate control, there should be another failsafe location with minimal controls consisting mainly for the lockdown of all gate controls and/or override of tower control. Typically a location in the Enforcement Building situated outside the perimeter that also has a visual view of the gates is a good location.

All gates in the vehicle sally port should be interlocked including both vehicle and man gates, meaning only one gate at a time can be open. For instances when two gates need to be open at the same time, a separate manually operated "interlock override" switch is activated. While activated, this switch beeps to remind the officer that override is on. There should be no controls inside the sally port for any of the gates.

For the proposed men's prison site, five towers should be provided. For the proposed women's prison site, three towers should be provided.

FOOTNOTES SECTION 4

INFORMATION INCLUDED IN APPENDIX D

Caterpillar *"Solar"* Gas Turbine Generator Sets

GE-Jenbacher Type 6 Turbo Generator Specifications

GE Model GE-10-1 Gas Turbine Specifications

Rolls Royce 501 Gas Turbine Specifications

Gas Turbine Maintenance Considerations

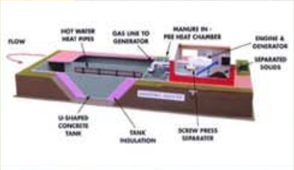
Acoustic Terms and Definitions

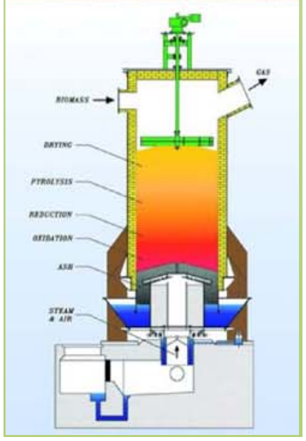
Near Field Power Plant Noise Considerations

Power Plant Layout Planning Considerations

Gas Turbine Emissions and Control

S&C 15kV Distribution Switchgear





SECTION V: RENEWABLE ENERGY

INTRODUCTION

The present review seeks to identify probable renewable energy opportunities and technologies for a proposed Utah State Prison on a site in Rush Valley, Utah. There is no assumption that renewable energy can replace or displace fossil fuel energy from the utility grids, but rather the assumption that economics and environmental motivations will soon propel both government and the private sector to transition aggressively toward integration of renewable energy in many forms into facility energy supplies. We seek also to make the case for rigorous energy demand reductions—'efficiency'—as an essential first step toward 'high performance prison' planning, design and construction. Singular, 'silver bullet' solutions to energy needs are rare, if not illusory. To be sure, it is possible for a single renewable energy resource to supply a facility with all the energy it needs, and more, given sufficient, focused investment. The Draper Correctional Facility has taken advantage of geothermal resources for an important part of its energy needs. Our glimpse into the crystal ball reveals a materializing vision of landowners, especially those among government agencies, doing all they can with given pieces of property to develop renewable energy resources in concert, to create economic vitality, clean jobs, and a landscape as economically productive as possible through exploration of clean energy as economic development driver. As a consequence, this study seeks to inventory not only the individual energy resources and the various technologies that may effectively capture and convert to usable energy, but also combinations of resources and technologies for sustainable, synergistic benefits, all built on a foundation of energy efficiency through sustainable, integrative facility design and construction.

Energy and resource efficiency has emerged as a complex, critical issue in the creation of government facilities of all types. Correctional facility planners have responded in recent years with more energy efficient, environmentally sustainable facilities. Several states, particularly on the West Coast, have built advanced, 'certified-sustainable' correctional institutions, using US Green Building Council 'LEED' certification (Leadership in Energy and Environmental Design) for 3rd-party verification of efficiency and sustainability measures attained.

Although the Utah Department of Corrections has not identified LEED certification as an objective, the Utah State High Performance Building Rating System encompasses a portion of LEED values and methods, primarily emphasizing verification by commissioning of energy efficiency of each building created by DFCM. Other prisons, notably in the western United States, have constructed renewable and efficient energy systems integral with strategies of energy reliability and budget independence from price fluctuations.

Regardless which, if any, approach is formally designated to energy efficiency, renewable energy generation and sustainable building, a comprehensive analysis of the adaptation of a facility concept/program to a specific site must screen technologies and technology combinations for congruence with Owner's objectives and needs, as well as comparative economic feasibility. This study extends review of energy technologies to the larger context of sustainability, here defined to include selective aspects of LEED certification in an 'integrative' manner: energy, water and other resource efficiencies, primarily as a discipline to assure consideration of all relevant opportunities and concerns; and the additional opportunities for operational and maintenance accountability afforded by complementary LEED disciplines.

A central feature of this review focuses on the Owner's need for energy reliability and redundancy, and the comparative capacity of various renewable energy resources to meet this energy reliability need economically. Short of discovering another 'silver bullet' energy resource at the proposed site, we must consider some combination of renewable energy applications as the most likely scenario for sustainable energy supply for the facility, integrated with an energy efficient facility plan and design.

FACILITY OWNER'S OBJECTIVES AND NEEDS

SECURITY

The paramount concern of the Department of Corrections is security, as a matter of clear public purpose, in support of public safety. To the extent that energy reliability and energy costs make up important aspects of the Department's institutional strategy, these factors must be considered as part of the security mission of the proposed facility.

ENERGY RELIABILITY AND BACKUP

Energy reliability is essential to the core purpose of correctional facility security. No latitude for error exists in this essential relationship among energy reliability, systems function, and backup redundancy. Brownouts and blackouts experienced in other parts of the country cannot be allowed in the State Correctional System facilities. This complex but critically important value, that of the highest level of reliability, may alter otherwise conventional evaluations of energy systems.

COST AND FUTURE PRICE STABILITY

Energy costs respond to market forces, including distant trends and events beyond control of state governments or agencies. In a facility as large and intensive as a state prison, energy consumption levels are equivalent to moderately large towns or industrial operations. Although a large proportion of total energy demand in a prison is non-essential, the magnitude of essential energy needs must be met with redundancy, and much of it with multiple redundancies. As has been demonstrated in events such as the California 'energy crisis' and in budget struggles essentially everywhere for public funds for essential services, energy costs are integral to cost projections.

Electricity, natural gas, diesel fuel, gasoline and other fossil fuels fluctuate in price according to markets, which also respond to extremely rapid population and economic growth in the developing world, as well as within our own nation. As with water prices, future energy costs are seen to be capable of at least an order of magnitude of variability. Budget certainty becomes nearly impossible, except through strategies strongly dependent on demand reduction through efficiency coupled with availability of renewable energy.

PEAK DEMAND AVOIDANCE AND ENERGY REDUCTION

Variation patterns in energy demand may result in 'peaks,' incurring extremely high demand rates from the electrical utility, not only for the increment in excess of agreed demand levels, but carried over to portions of conventional energy consumption. These peak demand charges may accumulate, significantly elevating average electrical costs. Thus, an additional value of alternative energy systems can be the avoidance or minimization of demand charges through leveling strategies, or through the creation of relative grid-independence for portions of demand that are episodic in nature.

EXPANDABILITY

Estimated Utah State Prison electrical demand for the existing Draper prison is in the range of 3.7 to 5.0 megawatts, as reported elsewhere in this document. Geothermal energy provides a large amount of heat for culinary hot water and space heating, not quantified thus far in electrical equivalency units (estimated to be on the order of several thousands of megawatt-hours electrical equivalent/annum). Projected Prison expansion will, of necessity, increase electricity demand proportionally, minus efficiencies and alternative, renewable energy resources that may be integrated into facility energy supply. Demand for non-electrical energy forms, such as culinary hot water, space heating, and cooling (which may or may not be fueled by electricity) will increase with facility capacity, but may do so according to a strategy or design.

SUSTAINABILITY

Environmental and social sustainability is commonly understood as development that "meets the needs of the present without compromising the ability of future generations to meet their own needs" (Brundtland Commission, WCED, 1983). Other, less simplistic and more place-specific concepts of sustainability can be made more useful by recognition of factors and realities that characterize a place, and even the needs of specific communities, cultures and ecosystems. A clear idea of sustainability should, as a consequence, be the product of constituent process, seeking to develop "sustain – ability": the ability to sustain an activity or facility, relative to scarce resources, occupant and employee health and welfare, vulnerable communities, and critical ecosystems and wildlife.

Due to realizations strengthened in decades since the Brundtland Commission's WCED process, energy is increasingly seen as the single most critical environmental issue among many, at the causal heart of global climate change, regional and local fossil fuel-generated contamination, regional haze, acid deposition, dependence on hostile regimes for oil, and physical damage to the land inflicted by coal extraction. The integration of factors considered here—need for reliability, cost restraint, price stability, peak avoidance, and expandability—may strongly inform energy strategy and facility design.

Expectations are increasing, moreover, to include environmental sustainability in this catalog of most important planning and design considerations. By applying a recognized discipline of environmental accountability such as LEED, a planning/design team may best assure that a responsible effort is made toward Project sustainability in both narrow and broad contexts.

PRISON ENERGY USE/APPLICATIONS – HEAT, ELECTRICITY AND FUELS

The Draper Correctional Facility reportedly uses between 3.5 and 5.0 megawatts of electrical energy, and an undefined quantity of heat. The heating energy is partially derived from use of the geothermal resource on the site, resulting in annual energy savings of about $300,000. A 'best guess' at natural gas rates for industrial/large scale users, and at the conversion factors to arrive at 'decatherms' and equivalent cubic feet of natural gas, places the quantity of natural gas replaced by geothermal heat in a range between 130,000 decatherms/year and 200,000 decatherms/year; and the volume of natural gas somewhere between 140,000,000 cubic feet and 180,000,000 cubic feet.

Liquid fuels such as gasoline and diesel, and possibly compressed natural gas, are used in vehicles, emergency generators and possibly other backup systems. Quantities cannot be estimated for liquid fuels. Regardless of the quantities, the services this electrical energy and heat energy must perform at the prison include at least the following:

- Direct space heating
- Culinary hot water
- Showers, personal hygiene, cleaning and wash-down
- Ventilation and air conditioning
- Food production, greenhouses, cooking
- Laundry
- Lighting
- Security systems and communications
- Emergency power
- Transportation

These functional needs must be met for the entire prison population and staff by whatever menu of energy forms that can be made available to best advantage, logistically, economically and environmentally.

Renewable Energy in the Great Basin Region

The American West's Great Basin physiographic province is rich in renewable energy potential.

Wind resources

Wind resources are concentrated at moderately consistent types of sites, the consequence of air mass movement generally from west to east, and due to canyon winds at certain locations. Wind energy occurs primarily along mountain range ridge lines; in many of the region's valley mouths, where mountain-canyon winds discharge according to diurnal cycles of valleyplateau thermal exchange; and of the passage of weather disturbances. As a result, economically feasible wind geography is erratic, but worthy of consideration and site-specific assessment.

Geothermal Energy

Geothermal energy usually corresponding to the fractured geological structure and history of the region, is widespread, though often at significant depth for high-temperature resources. Much of Utah's 'West Desert' region, to the northwest of the Rush Valley site, is thought to possess good high-temperature and intermediate-temperature geothermal resource. This prospectively superior geothermal resource appears not to extend, however, into the Rush Valley area.

Some areas to the south and west also are known to be populated with hot springs and excellent geothermal resources, as at the Blundell Geothermal Power Plant at Roosevelt Hot Springs, near Milford-Beaver, Utah. Intermediate-temperature hot springs or wells are used for aquaculture, greenhouses and recreation. Lower temperature geothermal energy exists at many locations as a localized phenomenon, while thermal inertia inherent in earth's relatively constant temperatures is available for heat exchange near-surface, essentially everywhere.

Solar Energy

Solar energy potential is pervasive, except on north-facing slopes and in forests. As demonstrated by solar energy projects in the northern tier of states, many forms of solar energy are worthy of evaluation for a wide variety of applications. Although intermittent, solar energy matches approximately the daily cycles of human and economic activity, making solar energy a valuable 'peak' form of energy.

Biomass Energy

Biomass energy is variably available for energy conversion in the region. Forests are biomass rich, while valleys are generally deserts, poor in biological productivity except where irrigated for crops on where water tables are near the surface. The two major forms of plant material that may offer opportunities for direct energy recovery or conversion to fuels, electricity or heat energy are urban and agricultural:

- Urban: municipal waste, sewage sludge and urban forest and 'green waste'; and
- Agricultural: animal, crop and rural forest waste materials, possibly including forest thinning residues from wildfire prevention, beetle-kill control and sustainable forestry activities.

The conversion of energy and nutrients from organic waste has been characterized as one of the most neglected, underutilized resource recovery opportunities of our time (*source: Gardner, Recycling Organic Waste, Worldwatch Paper 138, 1996).* Much of the waste stream that we treat as quintessentially problematic is an untested opportunity, especially in light of the catalog of mature technologies to accomplish conversions to energy, nutrients, value-added chemicals and countless valuable materials.

SITE ENERGY GEOGRAPHY AND ATTRIBUTES

The Rush Valley site has received little attention for its renewable energy development potential. No site-specific renewable energy resource assessments are in the public record, probably indicating that they have not been done.

Geographic and Climatic Setting

The Rush Valley site is situated among the easternmost valleys of the Basin and Range physiographic province, on a westward-sloping alluvial fan from the southern end of the Oquirrh Mountains. Climate is one of seasonal variability, from cold winters to hot summers typical of Great Basin semi-desert valleys. Extremes can bring winter low temperatures well below zero degrees F, and above 100 degrees F. Humidity is typically low. Annual precipitation averages approximately ten to twelve inches, uncertain for the proposed site due to variability and difference of circumstance from nearest weather stations.

In relatively moist years in such foothill environments, most precipitation tends to occur in the fall-winter-spring season; but dry years see precipitation spread more or less evenly through the year. Weather patterns are dominated by the swings among arctic Canadian, Pacific and southern continental air masses. Intermittent valley temperature inversions are common in winter, as well as in stagnant summer conditions. Cloud cover is relatively rare, allowing approximately

300 days per year of significant solar radiation to reach the ground surface. Wind is intermittent, a function of storm passage, valley-mountain winds, and the general movement of air from west to east across the region. Specific information about exact weather conditions for the area is anecdotal and subject to question, however, given the absence of scientific weather monitoring within the valley environment of the Rush Valley site. The nearest authoritative weather stations are located in Tooele, Provo, and southern Salt Lake County. Before design proceeds, establishment of a temporary weather monitoring station could fill in a great many data gaps, given observations from at least a full year, preferably more.

Wind Energy Potential

Insufficient information exists to judge wind energy resource potential. No site-specific wind resource assessment has been found, though statewide surveys provide some indications that a modest wind resource may exist, possibly seasonally limited. In general, it is not advisable to guess at wind resources in Great Basin mountain-valley terrain, nor wise to rely on anecdotal characterizations. Generalized information is included in the National Renewable Energy Lab summaries prepared for the Western Governors' Association 'Western Renewable Energy Zone Assessment' (WREZ), though data are derived from earlier Pacific Northwest Laboratory information (PNL, 1987, from WREZ 2008). Approximations of wind velocities presented in a summary from 20+ years ago ('West and Southwest Wind Atlas,' DeHarpporte, 1984), show the mountainous area immediately northeast of the Rush Valley site to vary seasonally from class 2 to class 5 wind resource potential.

This estimate was based on the international standard assessment tower height of 33 feet above ground. Wind speed typically increases with height, and both daily and seasonal variations may be dramatic with height. Given that utility-scale wind resources are measured typically at a minimum of 30 m (100 feet) or higher (50 m = 164 feet is common for very large turbines), it follows that a site wind resource assessment is imperative to facilitate an accurate evaluation of resource potential.

There are indications of spots of fair quality wind resources nearby, represented as very small, isolated areas on the Utah wind resource map of the National Renewable Energy Laboratory (NREL). At present level of site information, knowledge is insufficient to justify investment beyond a robust site assessment, with the possibility of using wind to meet specific, high-priority purposes. As a matter of procedure, all sites must be subjected to specific data-gathering at statistically meaningful height above ground level for at least a 12-month cycle before assumptions can be made about the magnitude and consistency of any given wind resource. This site, too, warrants resource verification. Camp Williams, Spanish Fork Canyon and Milford are each somewhat unique in geographic position relative to diurnal air movement patterns, not sharing apparent attributes with the Rush Valley site. It is worth noting that the Milford 'wind corridor' appears only slightly more significant than Rush Valley on the same NREL map.

An obvious recommendation is that anemometer data logging equipment with a suitable height, temporary tower (50 or 60 meters) with calibrated anemometer and data logging equipment should be installed to further develop data for renewable energy strategies formulation.

Geothermal Energy Potential

Virtually the entire West Desert of Utah, along with the south portion of the Salt Lake Valley, are underlain by moderate geothermal resources at widely varying depths, temperatures and flow or heat exchange potential. None of the water wells recorded for the immediate vicinity of the site shows thermal characteristics of a mid-temperature geothermal resource. High temperature geothermal resources are somewhat rare in Utah, and are not to be anticipated at this location. Common, earth-temperature conditions occur everywhere, however, and moderate temperature geothermal resources *may* be found at some unknown depth if one drills until those temperatures are encountered. Even then, warm water flow rates may not be sufficient to utilize. The likelihood of locating a geothermal resource of the magnitude of the Draper Prison site is not high.

Conversely, the potential utility is excellent of 'ground-coupled' or 'water-coupled' heat pump technology, drawing on the inertia of earth temperature as a heat source or heat sink for individual buildings and for a 'district' scale heating and cooling system. Innovative systems coupled to a wastewater treatment plant or high-flow sewer lines, to utilize their potential as heat sources/sinks, may also be attractive.

Solar Energy Potential

The Rush Valley site is in an area that receives an annual average of 5.0 to 5.5 kWh/m^2/day (NREL, Western Governors' Assn. 'Western Renewable Energy Zone Solar Resources, PV Flat Plate Tilted at Latitude,' Sept. 18, 2008). Seasonal variation ranges from a low of approximately 1,825 kWh/m2/annum to a high of approximately 2,007.5 kWh/m2/annum (NREL, solar data for Salt Lake City). While not approaching the highest insolation values seen in the desert Southwest, from southern Utah southward through Arizona, New Mexico, Texas and California, this solar resource is substantial, consistent and dependable, both for capture of solar energy as an electrical and a thermal resource. Aspect (orientation of slope) is east to west, which while not ideal is subject to satisfactory engineering responses, depending on technology.

Biomass Energy Potential

Rush Valley's desert environment offers little existing biomass resource. Subject to infrastructure and logistical limitations, however, proximity to urban areas presents underutilized waste streams of various sorts, including municipal solid waste, landscaping 'green' waste, and sewage sludge. Virtually every municipality and county is struggling with the challenge of exporting all forms of waste, some great distances at significant expense. Internal, facility-generated organic wastes and municipal waste equivalents may contribute to various opportunities for conversion to fuels or to thermal or electrical energy. In addition, opportunities exist to combine adequate irrigation water with abundant land to grow crops dedicated to energy production, possibly including cellulose or oil crops for conversion to various fuels or to heat or electrical energy.

Hydropower

Little or no 'run of stream' hydropower potential exists at the Rush Valley site. Slope is relatively gentle from east to west. For an 'engineered,' small-scale hydropower scheme, perhaps to complement other renewables, topographic gradient is 414 vertical feet in approximately 3.5 miles.

Site climate attributes and cycles for facility design

As discussed in this report, site-specific knowledge of microclimatic variability is essential to building energy optimization. This level of 'bioclimatic' or microclimatic data is not available for consideration in the present study. Prevailing valley-mountain breezes, for example, may cycle to offer opportunity for natural, low-energy ventilation. It is advised that site observation be carried out at intervals over the course of at least one cycle of seasons, to allow accumulation of design team knowledge of natural patterns of the portion of the site chosen for facility location.

PRISONS AND ENERGY

Imperatives for security of prison facilities raise concerns of energy reliability on a par with or beyond the highest-priority energy demand centers, such as critical defense facilities and government and corporate data centers. In addition, the reconciliation of budgets with energy price instability has emerged as an important recent concern. States are responding by creating energy-efficient and sometimes comprehensively sustainable prisons. Federal and state prisons in Pennsylvania, California, Arizona, Nevada and Washington state have been built or designed to high standards of energy efficiency and renewable energy dependence, with the express intention of reducing 'grid dependence.' Recent projects include the following:

- Federal Correctional Institution, Phoenix AZ: Parabolic trough collector solar-thermal system heats 40,000 gal/day of water for culinary, shower and laundry use for 1,250 inmates, offsetting approx. 1,000 mWh of electricity; financed through 'Energy Savings Performance Contract'. Source: US DOE EERE, Federal Energy Management Program, www.eere.energy.gov/femp; and *Mechanical Engineering Magazine/ ME Power, 1999.*
- Northern Nevada Correctional Center, Carson City NV, 'Renewable Energy Prison': Wood-fired biomass boiler, combined with 30 kW PV system; wood chips are sourced from regional for-

est thinning and beetle-killed forests. Excess electrical power is sold to power company. *Source: Alternative Energy News, Oct 2, 2006.*

- Allenwood Federal Correctional Complex, Lycoming County Pennsylvania: On-site county landfill for landfill gas capture, thermal and electrical generation. *Source: DOJ Solicitation, Sept 30, 2006.*
- Ironwood State Prison and Chuckawalla Valley State Prison, both near Blythe, CA: Photovoltaic (PV) installations in partnership with SunEdison power utility, 1.18 MW and 1.16 MW, respectively. *Source: Tom Cheyney, www.pv-tech.com, June 11, 2008.*
- Alameda County Juvenile Justice Center, Alameda Co. CA: LEED 'Silver' certification, despite counter-sustainable aspects of prison program requirements; energy efficiency emphasized. Source: *Doors and Hardware Magazine, June 1, 2008.*
- Penitentiary/Prison, Tucson AZ: Insulated tilt-up concrete panel construction offers high-performance thermal envelope. *Source: Concrete Monthly, September 2004.*
- Washington State Penitentiary North Close Custody expansion: LEED 'Silver,' exploring claimed "… link between greener prison environments and prisoner rehabilitation. *Source: Doors & Hardware Magazine, June 1, 2008.*
- Prisons in developing countries such as Zimbabwe are powered, heated and fueled (cooking gas) by anaerobic digestion biogas, converting facility and urban sewage, animal wastes, food and municipal wastes to usable energy. *Source: www.zimbabwemetro.com, Sep 10, 2008.*

SITE ASSESSMENT METHODOLOGY

ANALYTICAL SEQUENCE TO CREATE THE HIGH-PERFORMANCE PRISON

Renewable energy resource and technology screening should not be the first action on an agenda directed at creation of an energy-efficient, high-performance, 'low-carbon' facility of any sort. The initial purpose of this portion of the site suitability study was formulated as an inventory and assessment of renewable energy alternatives that may be available at the Rush Valley site.

Awareness has grown in the professional planning and design community, however, as well as among facility owners and operators, that buildings and groups of buildings can be made far more efficient and effective in their use of supplemental energy—that is, to use less energy, to be 'de-energized' by some factor—than conventional facilities of their type. Whether energy comes from the utility grid or from localized renewable energy sources, a system energy balance benefits if the facilities drawing on those sources minimize the energy required to function as desired. An appropriate *analytical sequence would be to* first envision an energy-neutral, inertial facility (a single building, a campus of buildings, an industrial complex, a city) and what it takes to get there, and then create energy inputs from grid and on-site renewables to provide the remainder of what is needed for the facility to function fully. Even when the day arrives when the utility grid provides 100% renewable energy, this thought process will still be appropriate.

Energy optimization of a new correctional facility must consider not only best practices in mechanical-electrical systems design, construction, and O&M (operations and maintenance), but also design integration of whole-building efficiencies. Beyond these steps toward minimizing energy demand, we then consider utilization of renewable energy and complementary energy alternatives. A prison imposes rigid design constraints, precluding many of the energy efficiency and renewable energy options that could be considered for office, institutional or other occupancy types. On the other hand, a correctional facility is a city, in many ways, or a fortress-village at the very least, affording energy integration opportunities not feasible under virtually any other circumstance.

Imperatives for isolation, containment and self-sufficiency, may be seen as rationale for renewable energy integration with high-performance building design, with opportunities of scale, and with 'closed-loop' systems integration for maximum facility independence from conventional resource supply grids. Reaching beyond 'conventional' facility design, it may be possible to create a truly 'high-performance' correctional facility by application of 'district-scale' renewable energy systems to clusters of buildings so well designed for thermal inertia that energy inputs can be relatively restrained and cost-effective, possibly allowing intermittent energy export to the utility grid.

INTEGRATIVE DESIGN TO MINIMIZE ENERGY NEEDS AND OPTIMIZE SYSTEM EFFICIENCIES

Assurance that basic principles of energy-efficient building design have been fully considered in planning and design is the first step toward creating any high-performance facility. Solar orientation, connection with the earth's thermal inertia, strategic connection with a site's climatic cycles, utilization of natural air movement, strategic manipulation of natural heating, cooling and light—these factors have given form to enduring, traditional buildings for centuries, and they inform the most efficient of advanced modern design and construction. Teams planning and designing high-performance buildings successfully will, of necessity, be interdisciplinary from the beginning and throughout the process. Internalizing the Owner's unique set of goals, objectives, needs and constraints forms a vision within which the planning/design team seeks to answer the question, "What is the best we can design here, for this Owner, for this programmatically defined purpose?"

Starting with 'the basics,' within identified constraints, interacting adaptively as design progresses, the design team asks, "What is the best energy performance that can be created for this facility?" Some process must be generated and maintained to cause the best possible answers to these questions to emerge, coalesce in design, and to be constructed economically.

Fundamental questions affecting energy expectations need to be answered in order for a planning/design team to progress responsibly:

- For what 'lifespan' will the facility be built? 50 years? 100 years? 200 years?
- What is the ultimate 'carrying capacity' or facility population within the projected facility lifespan, and how is it affected by energy supplies?
- How would the facility adapt to a future of more constrained energy availability?
- What energy resource, technology, market and regulatory changes are anticipated during this facility's lifespan? How could a 'carbon tax' affect energy fossil fuel pricing?
- What are energy price fluctuations projected during this time?
- In what ways may energy cost financing change in the future?
- How important is it to restrain energy costs?
- What changes are projected to occur for site geography, climate, demographic context, and the surrounding environment?
- At a site now surrounded by open space, what changes of land use are projected for the vicinity that may become constraints to energy systems and renewable energy choices?

INVENTORY AND ASSESS RENEWABLE AND COMPLEMENTARY ENERGY OPTIONS

An inventory of renewable energy resources that may be utilized at the Rush Valley site is constrained by recognition that no single resource or technology for utilizing a resource is available to meet the energy needs of a prison facility. The corollary is that more attention is necessary to possible combinations of resources and technologies in order to create a balance of reduced demand with optimized energy supply from diversified, redundant sources. We must pay particular attention to possible complementarities among resources and technologies, because no one possibility may offer sufficient energy supply.

Wind electrical generation; geothermal energy at low and medium heat levels; multiple forms of solar energy capture for heat and electricity generation; biomass conversion to heat, fuels and electricity; and small-scale hydropower generation will be considered. In addition, strategies and technologies for modifying energy supply timing, for transforming from one form to another, and for energy storage for strategic purposes.

INTEGRATIVE DESIGN AND ENERGY DEMAND REDUCTION

Effective utilization of energy, whether grid-sourced, fossil fuel generated, or produced by conversion of any renewable energy source, begins with minimization of facility energy demand. If the thermal envelope of each building is as inertial—i.e., as low in demand—as possible, then the quantity of energy that must flow into the facility is thereby minimized. A significant demand reduction may dramatically alter the relative feasibility of renewable energy utilization.

EFFICIENT BUILDING ENVELOPE, DAYLIGHTING AND ENERGY SYSTEMS

Passive Thermal Inertia

Buildings can readily be engineered with massive or highly insulated thermal envelopes, strategically engages with the earth's relatively constant temperatures. Concrete or masonry structures with thick, massive walls; partially buried, or 'earth-sheltered' structures; and buildings made of sod, adobe, soil or straw are all traditional methods used to create stable, thermally consistent interior environments. Keeping out cold or hot winds by sealing structures is a related strategy.

Daylight Optimization

Natural light is a valuable form of renewable solar energy, one that avoids need for other energy to get rid of unwanted heat produced by artificial lighting. At least 75-80% of electrical energy put into all but the most efficient light fixtures is converted not to light but to heat, an unintended byproduct of limited energy technology. Daylight captured and controlled without unwanted heat gain, therefore, offers valuable service to many building interiors. Correctional institutions have obvious limitations on placement of windows and accessible glazed openings, so daylighting opportunities may be restricted to clerestories, skylights, courtyards and other core open areas where security is not compromised.

Passive and Low-Energy Ventilation

Where possible, induced ventilation through controllable openings to natural exposures where desirable temperatures exist at any given time can avoid need for artificial cooling. Where windows are not permissible for security reasons, other design strategies may be considered, including 'earth tubes' and air draw into a space through small openings through massive structural elements. Tower-like chimneys have been utilized since ancient times in buildings world-wide to induce controlled circulation.

Passive Solar Heat

Solar heating is the most ancient of all architectural design strategies for tempering interior environments. Massive south-facing walls and floors can absorb heat and release it to an interior through most of the space's cool nighttime hours, effectively deferring the benefit of the sun's energy to the time when it's needed. Winter sun can be allowed into interior spaces when and where heat gain is desirable. Countless variations on passive solar heating have been invented, with varying degrees of success. Some combination of passive solar heating should be possible for a correctional institution, which, when combined with thermal inertia, greatly reduces need for supplementary energy in cool seasons or diurnal cycles typical of desert mountain climates.

High-Efficiency Lighting

A correctional facility is a perfect place for extremely high-efficiency lighting technologies at current state of technology. Objections often heard about LED (light-emitting diode) lighting contend that light quality is not consistent, or that light color changes over time. In commercial, retail or office environments, these objections may be legitimate. This should not be the case in a prison. Although LED first-costs are presently high, electricity savings due to very high efficiencies, approaching 90% compared to less than 40% for the best of conventional lighting types, would pay back rapidly.

Low-Energy Cooling

For essentially all of each warm season, evaporative cooling, combined with adequate ventilation and thermal inertia of the building envelope, can cool virtually any building in a desert environment. Whether utilizing a downdraft passive system in which a moistened pad chills air by evaporation in a tower, as is done in the Zion National Park transportation center, or utilizing a more technologically complex 'direct-indirect' evaporative cooler, there are few justifications for choosing energy-intensive, refrigerative cooling systems. Evaporative cooling is highly efficient as a supplement to a well-conceptualized building that maintains relatively cool conditions passively.

Commissioning

Buildings can be extremely complex mechanisms, requiring assurance of proper functioning. Even those that rely on passive and simple systems are dependent on the quality and integrity of primary thermal envelope, solar insolation control, daylighting through glazing and other openings, passive ventilation, and so forth, in order to function as designed and engineered. Buildings incorporating complex systems require monitoring of construction for verification that all components are assembled and controlled as intended, and that the finished, whole building is functioning properly. Commissioning is the discipline that performs this observation, monitoring and verification of assembly and functioning in compliance with design. Third-party, independent commissioning agents perform an extremely important service for the energy performance optimization of a facility.

Operations and Energy Management

Systematic energy management plans and procedures are necessary for optimizing energy performance scientifically, based on accurate data on all systems variables and equipment. Systems and controls designs should anticipate that O&M and energy management systems will be employed. Utilization of a formalized energy management plan is advisable, following on the O&M manuals and commissioning work at construction completion, adaptively carrying forward these disciplines throughout a building's operating existence.

Sustainable Facilities O&M

Integrative approaches to sustainable facilities management have been in development, notably for office and commercial buildings under BOMA (Building Owners and Managers Association) and US Green Building Council's 'LEED' programs. In 2008, a major revision of the 'LEED-EB' certification system (LEED for Existing Buildings: Operations & Maintenance) was put into use, completely focused on the provision of sustainable facility management tools to facility owners and managers.

Consideration of new or retrofit construction is left to other LEED certification systems, such as LEED-New Construction, LEED-Core & Shell or LEED-Commercial Interiors. This new LEED-EB: O&M system is the most comprehensive guide to sustainable operations and maintenance available (table of contents to 'LEED-EB: O&M Rating System' is attached). By mandating or encouraging development and implementation of written management plans and 'best practices' formulations, to be updated periodically for LEED-certified facilities, LEED-EB: O&M addresses at least the following sets of issues and practices:

- Site and exterior management, including erosion and stormwater control and site heat and light pollution control;
- Pest management;
- Water efficiency, indoor use and in landscaping and cooling towers;
- Energy efficiency, through 'best practices' management plan development and application of 'Energy Star' performance measures, as well as renewable energy incentives and carbon emissions reporting;
- Materials management, encompassing sustainable purchasing of durable goods, food, mercury-content in lamps, and in facility alterations and additions; and solid waste management for durable goods, consumables, facility alterations/ additions, and food through waste stream audit and management techniques;
- Indoor environmental quality, encompassing air quality 'best management practices,' green cleaning and related concerns.

The State of Utah Division of Facilities Construction & Management 'High Performance Building Rating System' (HPBRS), included in the DFCM *Design Manual,* is based on aspects of USGBC's 'LEED-NC' criteria, largely pertaining to energy efficiency. The HPBRS is particularly concerned with commissioning and related mechanisms to verify that energy system designs, along with intended construction and operations, are accountably executed. It is not intended to be a 'certification' system like LEED, involving independent, 3rd-party certifier review and participation, but rather is a DFCM standard required of most new State-owned construction.

Few of the LEED-EB: O&M concerns are addressed other than energy efficiency. Use of LEED-NC without certification, targeting a low level of credit scores, is approximately equivalent to executing the DFCM HPBRS. The weaknesses of the HPBRS lie primarily in site and interior environmental quality concerns.

WATER EFFICIENCY AND ENERGY EFFICIENCY

The use of water within the existing Draper Correctional Facility is reported to be very efficient, at present, equivalent to about 115 gallons per prisoner per day. A level of water efficiency equivalent to that at Draper, or better, is important to maintain in the proposed Rush Valley facility. Of equal importance to this review is the potential opportunity that water presents for integration into efficient, renewable energy and sustainable facilities management planning, design and operations.

Culinary Uses

Energy is consumed in treating, distributing and heating water for culinary use, in cooking, restroom use, showers and laundries. This 'embodied energy' in water is often overlooked as a significant energy demand activity.

Landscaping

Use of 'engineered' water, treated to culinary standards, for landscaping has been declining dramatically in recent years due to growing awareness of impending water scarcity in urbanizing areas of Utah. Through enlightened choices of low-water, climate-adapted plants, minimization of high-water turf or use of more drought-tolerant turf types, and employment of improved methods of water distribution, government agencies have led the way toward better use of water in creating attractive landscapes.

Wastewater

Processing of wastewater consumes a great deal of energy, as does the disposal of sewage sludge by truck transport to increasingly distant 'land composting' locations. Both the water and the organic constituents of wastewater constitute opportunities, not only for water efficiency, but also for renewable energy production and modification, as well as for soil nutrients. Reuse of water is addressed at the existing Draper Correctional Facility by use in greenhouses and nursery applications, as well as in landscaping. The Rush Valley site may offer opportunities to apply wastewater byproducts in ways not possible at most locations.

ENERGY USE/APPLICATIONS – HEAT AND ELECTRICITY

Available energy, whether from fossil fuel sources or from renewable energy production, may be used in a number of ways. If a given energy use can be made either significantly more efficient than conventionally, or made to depend on a renewable energy source, then the energy that would have been necessary for that use is 'liberated' for another application, or is saved or avoided entirely. The essential functions of energy in fulfillment of core tasks, however, persist as necessities for a major correctional facility.

- ***Direct Space Heating*:** Maintaining inmate and staff spaces at temperatures within ranges appropriate to each use or activity.
- ***Ventilation and Air Conditioning:*** Provision of fresh air and warm weather cooling, within acceptable temperature ranges.
- ***Culinary Hot Water:*** Provision of sufficient hot water for sanitation, showers, food preparation and dishwashing, laundry and other washdown functions.
- ***Food Production, Greenhouses:*** On-site produce farming for facility self-sufficiency and inmate activity may demand heated greenhouses for extended-season or year-round growing.
- ***Security, Site Lighting and Communications:*** Extensive interior, exterior, site and perimeter lighting; pervasive communications.
- ***Emergency and Backup Power:*** Emergency and redundant power capacity for support of all other electrical power functions.

RENEWABLE ENERGY INVENTORY AND ASSESSMENT

The purpose of this renewable energy resource and technology review for the Rush Valley site is to assess the potential for economically and strategically feasible non-grid, non-fossil fuel energy opportunities for a new State correctional facility. Criteria and considerations by which this review have been conducted are summarized here as 'terms of assessment.'

TERMS OF ASSESSMENT

Key Objectives

The State Department of Corrections requires that energy supply to the proposed new facility be economically cost-effective, price-stable in both short and long term, reliable, inexhaustible, and environmentally sustainable to the greatest extent feasible. By 'environmentally sustainable,' we here assume that low net carbon emissions is at the primary measure of this attribute. This report screens renewable energy resources according to these objectives.

Characteristics

The characteristics of an energy resource are functions of the resource and its conversion technologies. Characteristics must reasonably match the Owner's key objectives, either as stand-alone resource or in combination with other another resource-technology, or the resource in question must be disqualified for further consideration.

Certainty/Uncertainty of Resource

A great deal of information is available about some potential energy resources, but almost none about others. The state of available information, as well as interpolative information certainty, must be entered into any discussion of potential energy resources.

Steps to Confirm Resource and Further Assess

Resources vary widely in the costs and timeframes required to confirm or to further assess their magnitude, variability and availability for conversion to use. Resource-technology screening must approximate these variables.

Proximate Regional Supplementary Resources Availability

Consideration should be given to possible energy feedstocks or resources within a feasible distance of the site.

Energy Demand Patterns

Variations through time and facility spaces of energy demand must be considered in a robust assessment of renewable energy suitability. If temporal variations are likely in a renewable energy resource, as may be the case from day to dark or summer to winter, these variations must be considered for their capacity to match with facility energy demand. The capacity of a renewable resource to store energy for release or conversion when needed is another variable worthy of consideration.

Technical Suitability

Whether a renewable energy resource is appropriate for use depends on a number of technical issues, including it capacity to provide energy on demand, at any time. The magnitude of a resource is qualified by its 'capacity factor' (consistency of production).

Economic Approximations

First costs, operating costs and benefits (as facility utilization or as revenue from sale to utility grid) and operating costs need to be analyzed in order to compare resource-technology options. Little information is available to facilitate site-specific estimates, so only approximations can be provided per unit of energy produced. Further study is necessary to refine cost estimates. It is not possible to place values on benefits to Owner for intangibles such as energy independence from the utility grid, redundancy and backup, unless quantification were available for emergency generator fuels, etc., for the anticipated run time of those systems. Additionally, it is not possible to project fuel or electricity prices into the future, certainly not for the anticipated life-cycle of the facility.

No regulatory or government tax incentives are considered here. Current costs are sourced primarily from USDOE National Renewable Energy Laboratory (NREL) Energy Analysis Office (EAO), expressed in year 2000 dollars.

Scale of Energy Systems and Applications – Utility Grid, District and Buildings

Renewable energy resources may occur at scales conducive to conversion for use by an entire facility 'district,' sufficient only for an individual building, or at a magnitude to afford energy beyond facility demand, allowing export to the utility grid. It is also possible that a given site may possess excess renewable energy capacity, allowing energy to be sold to the electrical grid, or to be utilized as waste heat by co-located industries, businesses or housing. Scale is a critical variable of energy resource assessment, as a consequence.

Complementary, Hybrid Systems Potential

Renewable energy resources that occur according to a daily cycle, such as solar-electricity, or weather dependent patterns, may be significant only when other, complementary technologies can be matched with them to convert the net, hybrid resource to a supply pattern to match the Owner's key objectives of schedule reliability. Storage is an important possibility for some energy forms, as is the relative financial feasibility of sale to the utility grid when production is beyond facility needs, balanced by purchase from the grid when production is low. Resources that offer the capacity to 'level' other resources, either by storage or by complementary generation timetables, are highlighted for those capacities.

PRELIMINARY RENEWABLES SCREEN FOR APPLICABILITY AT APPROPRIATE SCALES

Only a few of the many possible forms of renewable energy survive a preliminary screening process. (Refer to Table 1 – Technologies Screen for Owner's Objectives, and to Figure 1 – Renewable Energy Schematic Site Map).

If we conceptualize these 'survivors' according to their potential, functional services to the proposed Rush Valley Correctional Facility, the list narrows to the following probable candidates, all assuming that demand has been minimized to the greatest possible degree by integrative, high-performance building planning and design:

Heating

- Ground-Sourced (or Water-Sourced) Heat Pumps / Scale: Multiple Central Plants or by Quad
- Salt Gradient Solar Ponds / Scale: Central Plant
- Solar-Thermal – Evacuated Tube and Flat Plate Collector Arrays / Scale: Multiple Central Plants or by Quad

Rush Valley Renewable Energy Schematic Site Plan

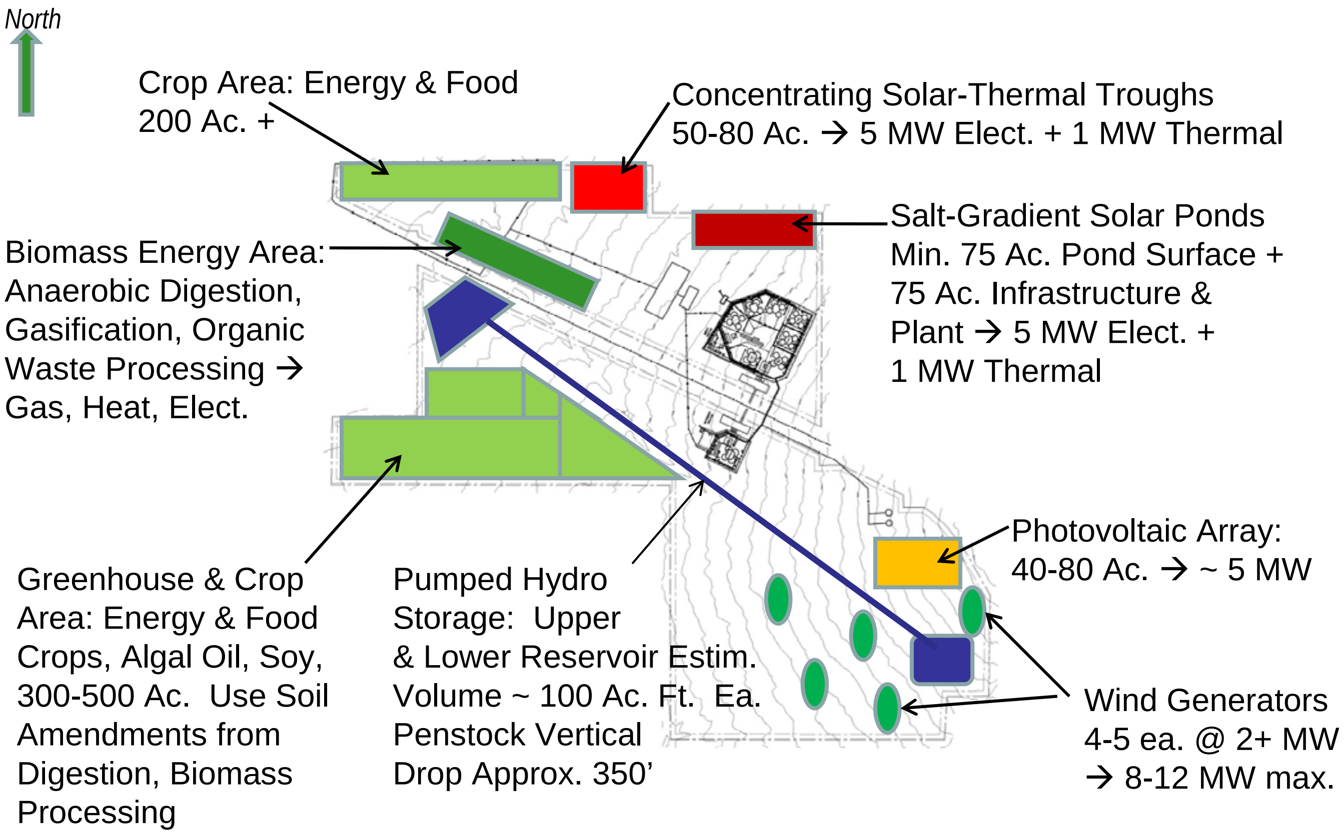


Figure 5.1: Renewable Energy Schematic Site Plan
Note: Energy Sources and Scales Represented are Conceptual, Subject to Field Verification for Greatest Utility to Facility

Table 5.1 - Renewable Energy Technologies Screen and Evaluation

TECHNOLOGY	PURPOSE - SERVICE PROVIDED	PRODUCTIVITY EXPECTATIONS	PRIMARY SYSTEM REQUIREMENTS	FUEL	ESTIMATED INVESTMENT COST/KW
WIND	As-occurs intermittent power	5 MW on demand requires utility grid exchange, build 7-10 MW	Multiple (3-5) 2-3 MW generators, high towers, to make up for low capacity factor	wind	$1,800 - $2,300 /kW installed w/inverter & controls, w/o transmission
SHALLOW GEOTHERMAL - LOW TEMP GROUND- OR WATER-SOURCED HEAT PUMP CENTRAL PLANT	Earth or water as heat source and sink; enhanced building systems efficiencies; can provide space heat and culinary hot water	Heat, cool and provide culinary hot water	Many deep wells (hundreds) , or linkage with sewage piping, or with water reservoir; increases electricity consumption	earth temperature / inertia; possible use of sewage pipe/flow temperature	Estim. For 8kW ground-sourced heat pump w/ direct evaporation: $22,000; $360/annum O&M
PV	Daytime intermittent power (peak) from monocrystalline panels on racks on ground	5 MW + at least 3MW to make up for low capacity factor	Tilted-rack fixed or tracking panels	sun	$6,800 - $8,000
SOLAR-THERMAL: SALT GRADIENT SOLAR PONDS	Intermediate-temp heat for direct use, electricity gener.; On-demand heat/ elect.	Size & engineer to provide min. 5 MW elect + 1 MW thermal; both are 'peak' capacities; must increase size to sustain outpout	75 Acres Min. pond surface; ~ 75 Ac. Infrastructure, support & generation; external heat exchanger, generator	sun	$3,000 - $4,000
SOLAR-THERMAL: EVACUATED TUBE ARRAY	Hot water for direct use; not suitable for conversion to electricity (scale limited)	At least enough to satisfy facility hot water demand	Arrays of evacuated tubes, circulation systems to conversion	sun	600 m^{2} Overall solar system ~ $400,000; District heating network ~$2.7 mil; total annual costs ~ $40,000-$55,000
SOLAR-THERMAL: PARABOLIC TROUGH HIGH-TEMP CONCENTRATING PLANT	Very high-temperature for heat use, conversion to electricty	Size & engineer to provide min. 5 MW elect + 1 MW thermal; 'peak' demand would require large-scale storage	Solar concentrating troughs, central plant, heat distribution and conversion infrastructure, high-capacity storage	sun	estim. $10,000/kW (for 50 MW plant, including molten salt storage)
BIOMASS-ANAEROBIC DIGESTION TO BIOGAS	Gas production for direct use (heating, cooking, heating water), cogen--> electricity	Sufficient for entire facility; gas can be used for transportation	Biomass infrastructure (internal and import); prep/processing area, not more than 10 Ac.	sewage sludge, food waste, crops, ag waste	Esitm. $1,500-$2,000/kW using conventional generators; can be much lower depending on efficiencies & feedstocks
BIOMASS-GASIFICATION TO SYNGAS	Cogeneration (steam and power, with heat available for direct use in 'district' schemes); Gas production for direct use (heating, cooking, heating water), cogen	Sufficient for entire facility; gas can be used for transportation	Biomass handling and preparation, plant facility, infrastructure	wood waste from urban forestry, landscaping, forest thinning, cellulosic crops or ag waste, wood municipal waste	$1,500 approx. (for 100 MWe plant proposal); recent Lufkin, Texas case costing 2,000/KWe +/-)
SOLAR UPDRAFT POWER TOWER	Wind electricity generation nearly all hours; potentially acts as greenhouse	Theoretically, all of facility needs plus exported electricity generation	very large translucent canopy, very tall tower	sun-generated wind (chimney effect)	$16,000-$20,000
HYDRO - PUMPED STORAGE	Energy generation from water stored in elevated reservoir, generating power in high-demand periods; use 'base' power to return water from lower reservoir to high	Intermittent or as-needed for high priorities, and to capture advantageous pricing for 'peak' power; Scale likely to be relatively small for this gradient	High reservoir, low reservoir, penstock, turbine/ generator and associated piping, power system	Gravity and adequate water	Unknown; depends on topography, soils, reservoir construction, penstock, generator turbine (s)/pumps
HYDRO - MICROTURBINE	Small-scale Electricity generation from in-line waterflows	Small; fraction of facility needs, but important for consistent availability, low cost	Small Kaplan generators at suitable locations in supply water and wastewater streams	Gravity in supply water and WWTP effluent flows	Unknown; depends on flows, engineering variables; European case: ~ $8,300/kW w/Kaplan generator, 5.9 m head, 40 m3/sec flow

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SOURCES: US DOE NREL Energy Analysis Office; Kaltschmitt et.al., 2007, Renewable Energ; Kreith & Goswami, 2007, Handbook of Energy Efficiency and Renwable Energy; Namovicz, 2005, EIA Projections of Renwable Energy Costs.

Table 5.1 (continued) - Renewable Energy Technologies Screen and Evaluation

TECHNOLOGY	ESTIMATED COST: 5 MW PLANT	ESTIMATED COST/ kWhr (O&M)	SYNERGIES WITH OTHER TECHNOLOGIES	ENERGY STORAGE?	OPTIMUM SCALE & AREA REQUIREMENTS	CRITIQUE
WIND	$9.25 mil. - $11 mil. excluding transmission	$0.03-$0.05/kWhr	Pumped-storage hydro stores, makes available to facility on-demand	No. Requires complementary technology	Either facility scale (3-5 MW) or Utility scale (>10 MW) 0.1 acre / generator; surface can have other uses	Feasibility contingent won wind resource assessment; tentatively, doubtful, but should be verified
SHALLOW GEOTHERMAL—LOW TEMP GROUND—OR WATER SOURCED HEAT PUMP CENTRAL PLANT	N.A.; beyond advisable scale for single plant, though theoretically possible	N.A.; increases electricity use, eliminates natural gas useage	Solar-Thermal Evacuated Tube, Solar Ponds, Hi-Temp Solar Thermal Heat Output	No; theoretically possible to use earth thermal storage for solar or biomass heat	Facility scale; wellfield can require significant space; water-sourced or sewer-sourced can be small, spatially	Should be included in building energy efficiency designs, regardless
PV	$35 mil. - $45 mil.	approx. $0.22 - $0.30/kWhr	Low-voltage systems may offer greater efficiency; solar/wind hybrid may be advantageous	No; requires batteries or conversion to another form of energy (heat, mechanical)	If done, worth doing at facility scale or larger (not less than 5 MW); Estim. 20 acres	One of most likely candidate technologies, matching heat & electricity need
SOLAR-THERMAL: SALT GRADIENT SOLAR PONDS	$30 mil. - $40 mil.	Estim. approx. $0.15-$0.25/kWhr (est. O&M for 5 mW plant ~ $100,000/yr.)	Offers thermal storage for other heat generation; can 'level' or 'firm' intermittent generation out of synch with demand cycles	YES. Possibly the best energy storage mechanism of those considered	Optimally, central-plant scale for whole facility; ~ 75 Acres x 2 for 6 MW elect (5 MW elect. + 1 MW therm.)	Once highly developed, neglected for 20+ years; needs updating with current system technologies; potentially best match with facility needs
SOLAR-THERMAL: EVACUATED TUBE ARRAY	N.A.; beyond advisable scale for single plant, though theoretically possible	Est. approx. $0.22-$0.32/kWh thermal; Equivalent fuel costs approx. $0.22-$0.32/kWh	Other Solar-Thermal or Ground/Water-Sourced Heat Pumps	Modest scale tanks	Building or Quad Scale; Theoretically could be Central Plant Scale with other thermal technologies	Potentially very effective at appropriate scale
SOLAR-THERMAL: PARABOLIC TROUGH HIGH TEMP CONCENTRATING PLANT	$50 mil - $65 mil. (based on European cases of approx. 50 MW); annual O&M approx. $0.5 mil	Estim. $0.22-$0.30 / kWhr, O&M approx. $20/m2 of mirror	Heat use technologies, can be coordinated with ground/water-sourced heat pumps	Important to utilization off-peak hours; molten salt, solid materials and phase-change technologies well-developed for storage	Central plant scale or larger; effective for electrical generation	Optimally applied as large-scale facility using extensive land on site, producing peak power for DOC revenue, along with heat energy for facility
BIOMASS—ANAEROBIC DIGESTION TO BIOGAS	$8 mil - $10 mil utilizing modular digestors; depends on feedstock availability, logistic costs, processing, etc.	estim. $0.07-$0.10 / kWhr	Needs thermal storage; synergy with salt ponds	No	Unidentified; estimate 10 acres; if growing crops, require area for crops	Potentially complementary to facility needs for organic waste disposal, energy recovery
BIOMASS–GASIFICATION TO SYNGAS	$10 mil. Minimum (extrapolating Lufkin TX case costs)	Approx. 2% of investment, counting a portion of feedstock logistics, handling and prep.	Needs thermal storage; synergy with salt ponds	No	Large area for materials handling; estimate 10 acres; if growing cellulosic crops, require area for crops	Potentially effective if linked to waste wood supply chains from region
SOLAR UPDRAFT POWER TOWER	$80 mil. - $100 mil.	estim. $0.04-$0.06/kWhr (theoretically low operating costs, similar to wind)	Use of canopy as greenhouse makes food production, other energy possible	Can be supplemented with water under canopies to store heat, equalize generation	potentially thousands of acres	Futuristic; need very large facility to be worthwhile; quite expensive
HYDRO—PUMPED STORAGE	European case Est. $42 mil. for run-of-stream hydropower generation; $8,300/kW	Unknown; Must consider power consumed in return pumping to upper reservoir	Can level or 'firm' value of wind or other intermittent, off-peak generation, make power available when needed	Yes; one of best mechanisms to complement other technologies	Large: Two reservoirs, depending on scale desired, probably at least 100 acres; requires significant water	Worth exploring to evaluate scale possible with 400' +/- relief, water available; not true renewable energy, but can optimize utility & value of power from other sources
HYDRO–MICROTURBINE	European case Est. $42 mil. for run-of-stream hydropower generation	$0.10/kWhr in European case (Kaltschmitt)	Could supplement intermittent generation from other sources	No	Essentially none beyond water system requirements	Should be done regardless, if flows are considered adequate, to capture incremental energy

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SOURCES: US DOE NREL Energy Analysis Office; Kaltschmitt et.al., 2007, Renewable Energ; Kreith & Goswami, 2007, Handbook of Energy Efficiency and Renwable Energy; Namovicz, 2005, EIA Projections of Renwable Energy Costs.

Cooling

- Evaporative, with Natural Ventilation (part of High-Performance Building design)
- Ground-Sourced (or Water-Sourced) Heat Pumps / Scale: Multiple Central Plants or by Quad
- Energy Storage: Salt Gradient Solar Ponds – Heat Storage / Scale: Central Plant
- Pumped Hydro – Electricity Storage / Scale: Central Plant

Electricity

- Salt Gradient Solar Ponds & ORC Generator / Scale: Central Plant
- Solar-Updraft Tower Power Plant / Scale: Central Plant
- Solar-PV / Scale: Present, Isolated Small-scale; Near-Future, PV Farm
- Biomass Thermal and Electrical Generation – Anaerobic Digestion à methane / Scale: Central Plant

Gas and Electricity

- Biogas-Anaerobic Digestion / Scale: Central Plant
- Syngas-Biomass Gasification / Central Plant

These resource/technology combinations appear, at this preliminary assessment point, to be worthy of further investigation for the provision of listed functions and services. Others may emerge in the course of site-specific investigation. Rapid technological change may enable some now estimated to be of second-rank priority to rise to the top of the priority list. Site-specific wind resource assessment, for example, may either be found to be greater at 90-meter height above ground than anecdotally estimated, or low-velocity generators may become commercially available soon. Either could move wind into the list of resources worthy of emphasis at facility scale, if not utility scale.

Looking into the earth, further exploratory drilling could uncover the existence of an intermediate-temperature geothermal resource that has not been encountered in water well development. Imposition of a carbon tax or enactment of carbon ‘cap and trade’ legislation could shuffle priorities significantly and iteratively as our energy economy adjusts and readjusts to changing financial, investment and environmental conditions.

The further evaluation of renewable energy utility to the Rush Valley DOC Facility should be both methodologically rigorous in engineering economic applications of these likely resources, and open to changing possibilities.

RECOMMENDATIONS AND FURTHER INVESTIGATIONS

Gaps and deficiencies exist in data on nearly every form of renewable energy in the Rush Valley area. Site-specific measurement, data-gathering and analysis must be done at the Rush Valley site in order to remedy these gaps and deficiencies. A robust basis in credible data is imperative to consider high-performance facility design for efficiency and energy reduction, and to evaluate renewable energy options at a refined level, based on levels of design needed for each resource/technology combination.

Transition to Renewables: Integral to an advanced energy strategy, an option should be developed for transition from fossil fuel dependence to increasingly high proportions of renewable energy.

A high-resolution, quantitative inventory of possible resources that may be imported from outside the site, but within feasible logistical distances, also should be undertaken. This is especially true for various forms of biomass in municipal solid wastes and sewage sludge in need of disposal solutions, and for agricultural wastes and possible crops for use in biomass-to-energy conversion.

Wind resource assessment should be done formally, without expectation that a first-class wind resource will be identified, but with the possibility in mind that sufficient wind resource may be present to complement other renewables, and that wind generation technology may improve rapidly in the next few years. A marginal wind resource now may become economically and energetically viable within the next few years. Having credible data on hand will speed iterative feasibility review in future.

Environmental and regulatory permitting issues should be studied in detail for each of the candidate forms of renewable energy that pass screening. This is true for all renewable energy technologies; each has its critics and its practical challenges:

- Avian mortality studies for wind generation, though large generation units move so slowly that this has become nearly moot; small generation is still high-speed, for the most part.

- Aviation safety concerns where towers are proposed to be erected, especially proximate to a military facility, or in possible flight paths near other military facilities.

- Groundwater contamination concerns must be addressed for salt-gradient solar ponds, in order to define regulatory expectations in Utah for subsurface preparation, containment liners and O&M compliance. Any limitations on salts and compounds that can be present in salts need to be understood at the outset. Salt sources and logistics for procurement of the thousands of tons of salts needed must also be explored.

- Community concerns must be approached methodically and transparently.

Practical, operational concerns must be explored candidly with Department of Corrections management and staff, to assure that no barriers would be created to effective security and inmate containment, as well as to practical management of energy systems serving the facility.

Integration of planning and design: Energy review process can most effectively proceed by a series of intensive workshops or charrettes, attended by key stakeholders, planning and design experts, prior to committing to building the facility on the site at Rush Valley. Without promises or expectations, a focused group of creative, knowledgeable and technically prepared individuals can advance a vision and consensus for facility creation in a matter of days.

Key deficiencies and gaps, particularly, can be identified for further investigation. The question cited earlier in this report can be answered substantially through this process: “What is the best we can design here, for this Owner, for this programmatically defined purpose?” It will be possible, especially, to bring focus to the manner by which renewable energy can be balanced with conventional energy supplies from utilities, progressively over time shifting to an increasingly carbon-free, economically and environmentally sustainable facility.

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SECTION VI: PROJECT COSTS

CONSTRUCTION COSTS

This section provides cost estimates for three different scenarios, which are described below. Itemized cost estimates for each scenario can be found on the following pages. Appendix __ contains further detail for each scenario.

The first scenario consists of a 6,000 bed facility located in Rush Valley. The facility would have seven male housing pods and one female housing pod. The estimated cost for this scenario is $984,635,000.

The second scenario represents an expansion of the first scenario. It would provide 10,000 beds in ten male housing pods and two female housing pods. It not only includes more housing pods, but also additional support structures and site development. The estimated cost for this scenario is $1,345,505,000.

The third scenario consists of a 6,000 bed facility located just west of the existing prison in Draper. This scenario would incorporate a development program identical to the Rush Valley 6,000 bed scenario. The cost of this scenario will, therefore, be very close to the Rush Valley 6,000 bed scenario. However, this scenario will cost somewhat less due to the proximity of existing utilities. The estimated cost for this scenario is $973,069,000. While this amount is somewhat less than the Rush Valley total, the difference is only about one percent of total construction cost.

Note that land and finance costs are not included in the estimates. In addition, the scenarios are current costs and do not include inflation. Costs include contractor general conditions, overhead and profit, and are based on a competitive bid basis between 3-4

Table 6.1: SCENARIO 1 - RUSH VALLEY SITE - 6,000 BEDS
Order of Magnitude Cost Estimate

SECTION		COST
BUILDINGS - MALE FACILITY		
	INSIDE SECURE PERIMETER	$74,234,000
	HOUSING (7 Pods)	$516,172,000
	OUTSIDE SECURE PERIMETER	$36,510,000
	PERIMETER CONTROL	$5,733,000
	ON-SITE MISCELLANEOUS IMPROVEMENTS	$4,447,000
		$637,096,000
BUILDINGS - FEMALE FACILITY		
	INSIDE SECURE PERIMETER	$28,206,000
	HOUSING (1 Pod)	$77,760,000
	OUTSIDE SECURE PERIMETER	$4,952,000
	PERIMETER CONTROL	$2,665,000
	ON-SITE MISCELLANEOUS IMPROVEMENTS	$693,000
		$114,276,000
ON-SITE UTILITIES (Male & Female)		$16,019,000
OFF-SITE UTILITIES (Male & Female)		$20,317,000
TOTAL (Construction) per SF		$787,708,000
SOFT COSTS - 25.0%		$196,927,000
TOTAL		**$984,635,000**

bidders. A twenty-five percent allowance for soft costs was included. Soft costs include architectural and engineering fees, furniture, fixtures and equipment, contingency, and owner costs.

Table 6.2: SCENARIO 2 - RUSH VALLEY SITE - 10,000 BEDS
Order of Magnitude Cost Estimate

SECTION		COST
BUILDINGS - MALE FACILITY		
	INSIDE SECURE PERIMETER	$74,234,000
	HOUSING (10 Pods)	$735,068,000
	OUTSIDE SECURE PERIMETER	$40,630,000
	PERIMETER CONTROL	$7,043,000
	ON-SITE MISCELLANEOUS IMPROVEMENTS	$5,110,000
		$862,085,000
BUILDINGS - FEMALE FACILITY		
	INSIDE SECURE PERIMETER	$28,206,000
	HOUSING (2 Pods)	$136,637,000
	OUTSIDE SECURE PERIMETER	$5,680,000
	PERIMETER CONTROL	$3,573,000
	ON-SITE MISCELLANEOUS IMPROVEMENTS	$709,000
		$174,805,000
ON-SITE UTILITIES (Male & Female)		$16,119,000
OFF-SITE UTILITIES (Male & Female)		$23,395,000
TOTAL (Construction) per SF		$1,076,404,000
SOFT COSTS - 25.0%		$269,101,000
TOTAL		**$1,345,505,000**

Table 6.3: SCENARIO 3 -DRAPER SITE - 6,000 BEDS
Order of Magnitude Cost Estimate

SECTION		COST
BUILDINGS - MALE FACILITY		
	INSIDE SECURE PERIMETER	$74,234,000
	HOUSING (7 Pods)	$516,172,000
	OUTSIDE SECURE PERIMETER	$36,510,000
	PERIMETER CONTROL	$5,733,000
	ON-SITE MISCELLANEOUS IMPROVEMENTS	$4,447,000
		$637,096,000
BUILDINGS - FEMALE FACILITY		
	INSIDE SECURE PERIMETER	$28,206,000
	HOUSING (1 Pod)	$77,760,000
	OUTSIDE SECURE PERIMETER	$4,952,000
	PERIMETER CONTROL	$2,665,000
	ON-SITE MISCELLANEOUS IMPROVEMENTS	$693,000
		$114,276,000
ON-SITE UTILITIES (Male & Female)		$16,019,000
OFF-SITE UTILITIES (Male & Female)		$11,064,000
TOTAL (Construction) per SF		$778,455,000
SOFT COSTS - 25.0%		$194,614,000
TOTAL		**$973,069,000**

OPERATIONAL COST COMPARISONS

Changing the location of the main prison facility or adding a third site to the current prison system will result in additional operational costs. Wikstrom worked with the budget manager at the Division of Institutional Operations to determine which costs would change if the prison were to move location. Categories taken into consideration were medical, supplies, natural gas, trash, transportation and freight. Of these categories, most costs currently incurred for operations and maintenance are contracted through the DOC. Current contracts state that the contract holder is responsible for delivery costs. Since these contracts are already in place they will not change until the contract expires. A contract holder may be able to renegotiate their rate at the end of the contract period if the location is changed; however, impacts of these potential changes cannot currently be quantified due to the difficult nature of predicting the outcome to contract negotiations. The one area where a change in cost can be quantified is transportation. Transportation related expenditures represent approximately four percent of the Draper facility's $73.7 million budget.

The cost of providing prisoner transportation is directly related to the change in distance between the prison and the destination. A model was created to estimate the potential cost of a new prison site on operational budgets. The model was designed to estimate the number of trips and mileage to and from Draper and Rush Valley. The number of trips was grown proportionally to the number of average daily prisoners at each facility. In each of the scenarios presented in this section, the maximum average daily prisoners was obtained by using the assumption that the greatest number of prisoners any facility could hold was 95 percent of total available beds based on information from the Bureau of Research and Planning at the DOC.

Prisoner transport trips can be classified into five main categories: inmate placement program ("IPP"), board of pardons and parole ("BOPP"), court appointments (e.g. appeals, hearings, custody issues, etc.), medical needs, and assignment. Each trip type is associated with a different location. Based on the location for each trip, the number of miles between the proposed site and the destination can be calculated. The percentage each trip type of total prisoner trips is located in Table 6.4.

All trip data was provided for the entire prison system. To better represent trips actually borne by the Draper facility, all trips were proportionally allocated based on the number of prisoners, where programs are housed, and where prisoners attend BOPP meetings.

Table 6.4: Distribution of Trips by Five Main Trip Types, 2007

Trip Type	Percent of Total
Inmate Placement Program	24%
Board of Pardons and Parole	10%
Court	33%
Medical	27%
Assignment	7%
Total	**100%**

Source: Department of Corrections

The Inmate Placement Program allows the Utah State Department of Corrections to lease bed facilities in county jails to house state prisoners. Currently 22 county jails lease beds to the state. Trips classified under the IPP take place between leased beds at county facilities and state prison facilities. To model these trips, the total number of IPP trips was distributed by the percentage of leased bed space each county holds. Across the state there are a total of 1,596 leased beds. The county with the most leased space available is Beaver County with 360 beds.

Board of Pardons and Parole meetings are held at three prison facilities in the state for DOC prisoners: Draper, Gunnison and Beaver. All IPP prisoners that need to attend a BOPP meeting must be transported back to the nearest facility that holds BOPP meetings. Based on a shortest distance assumption, Draper would hold BOPP meeting for IPP prisoners in 12 of the 22 counties participating in the IPP.

Court trips occur between the prison and the prisoner's court of conviction. The percentage of prisoners convicted from each county was used to distribute these trips. 39 percent of all prisoners were convicted in Salt Lake County. A table showing the top five counties for percent of prisoner convictions in the system can be seen in Table 6.5.

Most medical primary care takes place within the prison facilities. If a prisoner requires a specialized test beyond the capabilities of the internal staff, that prisoner is taken to the University of Utah Medical Center ("UUMC"). To maximize efficiencies, all chronically ill prisoners are housed at the Draper prison. The vast majority of all trips classified as medical occur between Draper and the UUMC.

Table 6.5. Top 5 Courts of Conviction in the Utah Prison System

County of Conviction	% of Prisoners
Salt Lake	39%
Weber	20%
Davis	11%
Utah	7%
Washington	3%

Source: DOC, Wikstrom

Assignment trips are trips between the two main prison facilities, Draper and Gunnison. In the case of a full relocation these trips will be between Rush Valley and Gunnison. In the case of a partial relocation, where the Draper site remains open and a third satellite site is added, it is assumed that trips will be split evenly between the three sites.

Two transportation scenarios were run. One compared the cost of providing transportation for Rush Valley as a replacement for the current Draper facility. The second scenario assumed Draper would remain as the main prison facility and Rush Valley would be added as a third prison site.

Table 6.6 shows that in a full relocation scenario, transportation costs for the Rush Valley site will be greater than for the current Draper site. Transportation costs are consistently 30 percent higher for the Rush Valley site assuming both locations have the same number of beds. Table 6.6 shows the cost estimates related to transportation for both Draper and Rush Valley assuming a 4,000- (Draper's current size), 6,000- and 10,000-bed facility.

Table 6.6: Transportation Cost Comparison

Beds	Draper	Rush Valley	Difference from Draper	Percent Change from Draper
4,000	$3,767,192	$4,890,915	$1,123,722	30%
6,000	$5,515,635	$7,162,137	$1,646,502	30%
10,000	$9,012,521	$11,704,581	$2,692,060	30%

Note: Assumes all beds are filled to 95% capacity

Under a three site scenario (assuming 4,000 beds at Draper and 6,000 beds at Rush Valley) the costs borne by Draper increase from the full relocation scenario, since Draper retains BOPP and medical trips, while the costs for Rush Valley are slightly lower. Overall, the cost of providing transportation for 10,000 beds under a three site scenario is lower than providing these transportation costs under the full relocation scenario to Rush Valley. Keeping all beds at the Draper facility is still the most cost effective method for transportation due to its closer proximity to transportation destinations. Table 6.7 shows the transportation costs for a three site scenario with 10,000 beds.

Table 6.7: Transportation Cost Comparison: Three Site Scenario

Location	Beds	Cost
Draper	4,000	$4,685,881
Rush Valley	6,000	$6,177,819
Total	**10,000**	**$10,863,700**

Note: Assumes all beds are filled to 95% capacity

In addition to computing the three-site and full-relocation scenarios for Rush Valley, the costs of relocating a 6,000-bed facility to sites in Juab County and Box Elder County were run. This calculation shows that the transportation costs associated with new facilities in these counties is higher than the costs associated with a similar facility being relocated to Rush Valley. Of the two alternative sites, Rush Valley is much closer in transportation costs to Juab County than to Box Elder County. Of the three sites (Rush Valley, Eastern Box Elder County, and Northeastern Juab County), Rush Valley would have the lowest transportation costs.

Table 6.8: Transportation Cost Comparison by Site Alternatives, all with 6000 Beds

Site	Cost
Draper	$5,515,635
Rush Valley	$7,162,137
Juab	**$7,189,626**
Box Elder	**$9,287,614**

Note: Assumes all bed are filled to 95% capacity

Juab County's surprisingly similar anticipated transportation costs to Rush Valley's costs are in spite of its distance from Salt Lake City. The reason for this is that Juab County's more southern location reduces the mileage for many of the IPP trips since most of the beds available to the state are located south of Juab.

Although transportation costs estimated in these calculations are on par with Rush Valley, other operational costs will likely be higher in Juab County and Box Elder County than Rush Valley since both Juab County and Box Elder County are much farther from service centers than Rush Valley. If these additional operational costs were able to be quantified they would most likely be greater at Juab County than at Rush Valley. This would make the difference in total operational cost between Rush Valley and Juab County greater than what is shown in Table 6.8.

Appendix X: Salt Lake County Landfill Site Analysis

The area surrounding the Salt Lake County Landfill, located at 6030 West California Avenue, is defined as the area between I-80 and SR-201 and between the Kennecott tailings pile and 4800 West. (See Figure 1.) This area is characterized by numerous parcels of undeveloped land, with scattered industrial development. While at first glance this area may appear attractive due to the apparent availability of land, there are several obstacles that would discourage the development of a prison in the area. First of all, with the exception of some land owned by Kennecott and the Lee Kay Hunter Education Center, there are no properties that approach 500 acres, which was a major criterion used during the site selection process. If a new prison was built near the landfill, land would have to be assembled, necessitating purchase from two or more owners.

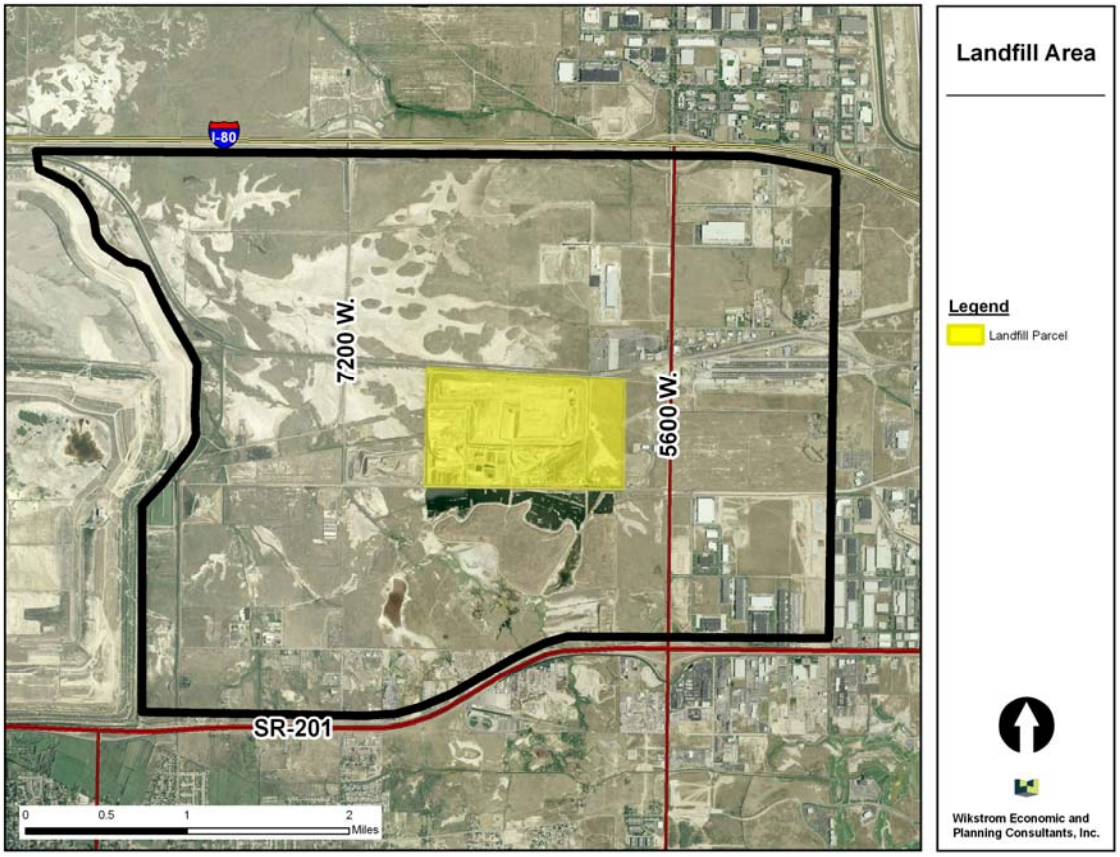

Figure 1. Landfill Area

As mentioned, there are two exceptions to the land assembly problem. The first is the State-owned, 1,000-acre Lee Kay Center for Hunter Education, which includes a shooting range and a large area for training hunting dogs. The eastern portion of the site has been developed with the gun range and associated buildings. The western portion of this site has been developed as a hunting dog training area, and includes constructed ponds and other terrain. The western area is large enough to support a prison complex, but it has substantial wetlands, making it difficult to develop. Development of a prison on this site would, of course, represent a major disruption to the operations of the Lee Kay Center.

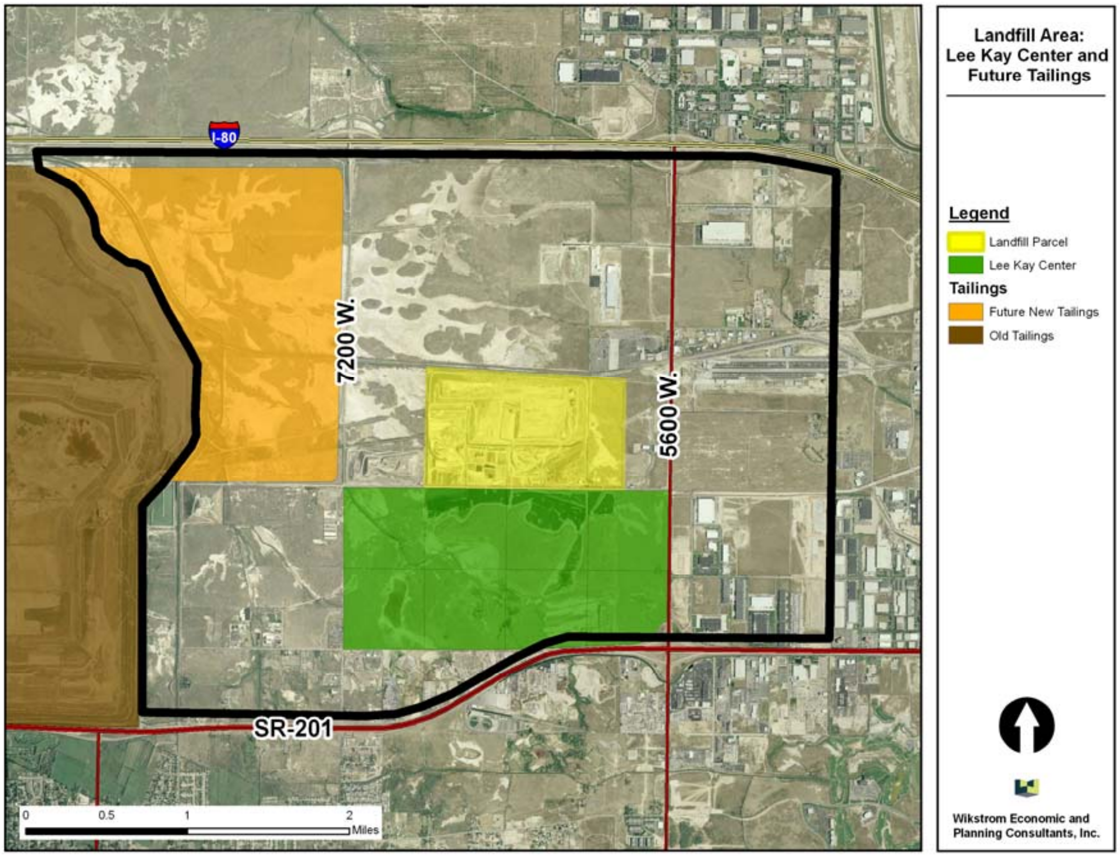

Figure 2. Lee Kay Center and Future New Tailings

The other exception is the Kennecott-owned land between Kennecott's tailings pile and 7200 West and between I-80 and 1300 South (shown in orange in Figure 2). The Salt Lake County West Bench General Plan, adopted in June of 2006, shows this area as part of two new neighborhoods called the "North Urban Center" and "Main Street Neighborhoods." While these developments may occur at some point in the distant future, Kennecott has other near-term plans. In recent discussions with Salt Lake City as part of the Northwest Quadrant Master Plan project, Kennecott indicated that it plans to expand the existing tailings pile to the east (but no further than 7200 West).[1] The possibility of a prison on the site does not reconcile with Kennecott's stated near- and long-term plans.

The elimination of the above properties leaves numerous smaller parcels owned by a diverse group of landowners. Many of these parcels have substantial wetlands, as shown in Figure 3. In

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[1] Telephone conversation with Everett Joyce, Senior Planner for Salt Lake City, August, 2008.

addition to having wetlands, the remaining parcels are all too small to support a prison complex. It would be difficult to assemble land in such a way as to avoid wetlands and still have enough property to build a prison complex.

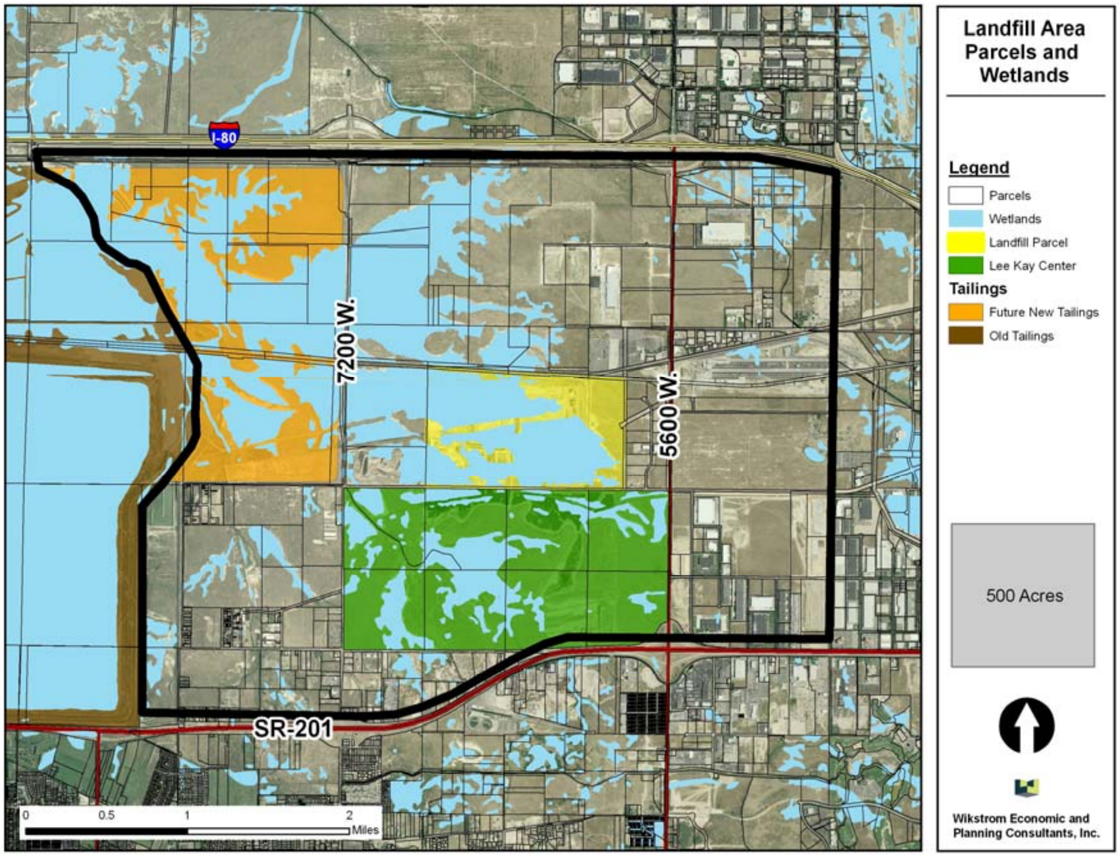

Figure 3. Landfill Area Parcels and Wetlands

A final obstacle to the development of a prison complex in this area is the close proximity to existing and future residential development. Figure 4 shows a draft of Salt Lake City's Northwest Quadrant Plan Framework as of July 2008 along with current residential areas in red. The current landfill will, at some point, be developed as a regional park according to this plan. Lands to the east and to the north of the landfill are planned for industrial uses. There are existing residential areas immediately to the south of the area. In addition, Salt Lake City's plan includes residential uses immediately to the north just across I-80. It seems clear that if a prison complex were built in this area, in a few years it would be faced with the same residential encroachment problems that have beset the Draper facility.

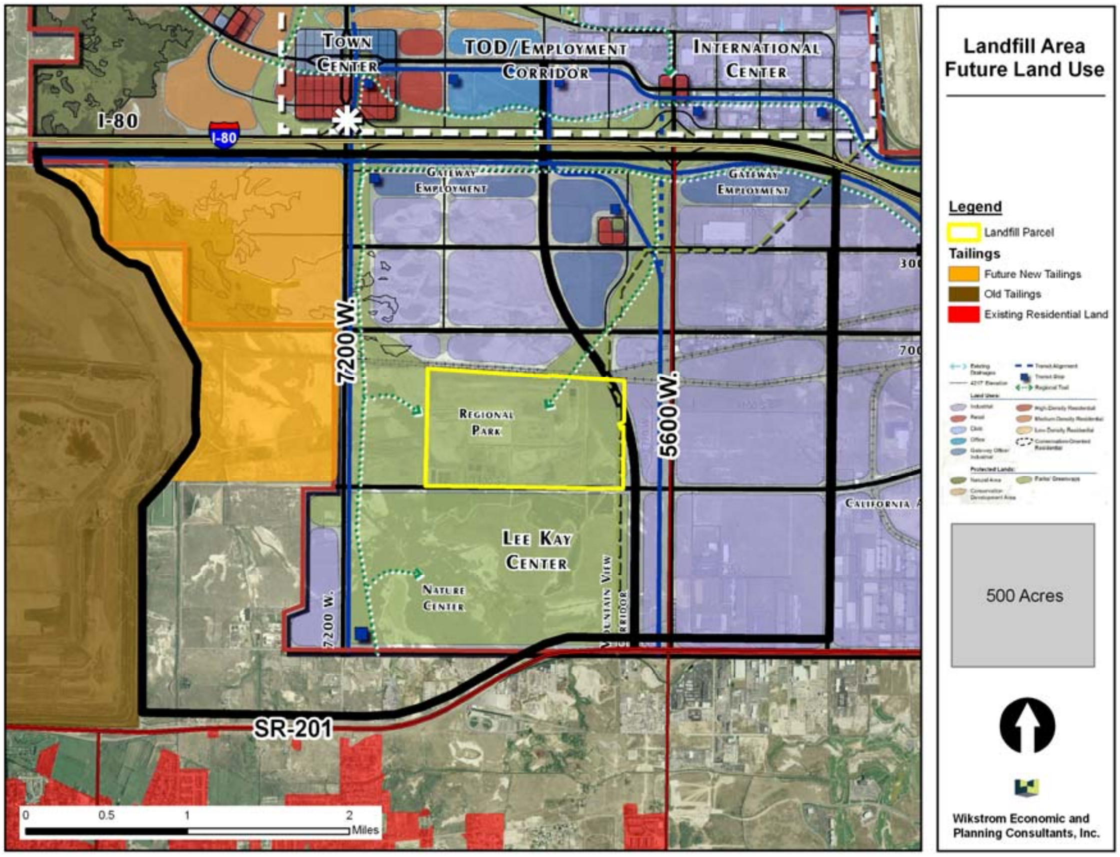

Figure 4. Land Fill Area Land Use

In conclusion, although the area surrounding the Salt Lake County Landfill may appear attractive for a new prison complex because of the large expanses of undeveloped land, in reality there are several major obstacles to locating a prison in the area. First, there are only two single-owner holdings large enough to support a prison complex, and both are unavailable for the development of a prison complex. The second obstacle to the development of a prison complex in the area is the existence of wetlands, which cover large portions of the area. Even if the Kennecott and Lee Kay Center properties were available, neither has enough non-wetland area to support a prison complex. Many other properties in the area also have substantial wetland areas. Finally, the current and planned residential uses near the area make the area less attractive. There are already homes just across the highway to the south and new neighborhoods planned across Interstate 80 to the north.

APPENDIX E: RENEWABLE ENERGY

RENEWABLE ENERGY RESOURCES CONSIDERED IN THIS ASSESSMENT

The Rush Valley site was subjected to *pro forma*, preliminary assessment of the resources listed in this section. All were examined for theoretical potential, and supporting data in available literature or on credible Internet sites, for large, 'utility' scale power or heat generation. This was done based on the realization that the State of Utah and the Department of Corrections can benefit from revenue that may accrue from energy generation in excess of facility needs, assuming that transmission infrastructure exists into the power grid. On the surface of our impressions of Rush Valley, no single resource appears compellingly strong with the exception of solar radiation. Nevertheless, whether indications exist that a given resource is available in quantity with dependability, or not, it is necessary to subject all reasonably feasible resource/ technology combinations to this preliminary screening.

WIND

The Rush Valley site may possess a marginal wind resource, but likely not a 'utility scale' wind generation opportunity. Given the low cost of resource assessment, it is advisable to perform thorough testing to measure the wind resource at 50 or 60 meter height for at least one year, in order to determine whether there is sufficient wind to utilize in a complementary or hybrid system, along with other renewable or grid-derived energy. If enough wind exists for small or facility scale applications, there may be a way to combine with other technologies to beneficial effect. At present, however, there is no evidence that this resource can be depended on. It is possible that worthwhile wind resources exist higher on the mountain to the northeast, on public lands, such that the resource could be developed for the benefit of the Rush Valley facility. Again, no specific data exist to support this idea, which would involve transmission via the utility grid, just as would a wind generation facility at any other remote location. This report does not suggest pursuing wind resources with the supposition of any serious immediate promise; but rather, that credible data be collected early in site consideration in preparation for low-velocity, efficient wind generation, now under development.

***Cost**:* Approximately 2.5-4.0 cents/ kWhr, utility-scale; 10 cents+/kWhr for small-scale applications, anticipated to decrease rapidly in upcoming 5-10 years. Operating costs assumed to be 0.5%/year.

Figure E.1: Large Suzlon Wind Turbine Installation

GEOTHERMAL

Although the Rush Valley site is on the northeast margin of a large region thought to possess significant utility-scale geothermal energy resource potential, essentially no data are available for any site within meaningful distance.

Low-Temperature, Ground-Sourced and Water-Sourced Geothermal

Virtually any location on earth possesses significant potential for one form or another of opportunity to use stable temperatures of earth, ground water and water bodies as heat sources and sinks, within ecological constraints. Coupled with heat-exchangers, or 'heat pumps,' systems can be engineered that are competitive with conventional heating and cooling systems. Where water flows or adequately large lakes, ponds or aquifers are available, relatively lower cost systems may be engineered at very high efficiencies. Wastewater may present such an opportunity, as may fire water storage reservoirs or reservoirs created to serve dual purposes, as long as those purposes are not mutually preclusive. The Rush Valley facility appears to offer several variations on this possible heat pump source/sink application. Costs may vary widely within a range from approximately that of conventional HVAC systems upward, but offering fuel independence, except for the electricity to run heat pumps.

A 'district' scale heat pump system for each of the two prison facilities, supported by solar or other renewable electrical generation system to provide operating electricity may offer one of the most dependable heating and cooling systems possible, providing culinary hot water capacity, as well. It must be noted that heat pumps shift a portion of total energy demand from natural gas over to electricity to run the heat pumps, themselves. Ground and water sinks may also be engineered to serve as storage mechanisms for excess heat, though the technologies involved are possibly less well suited to this site than to others.

An unusual, and possibly ground-breaking, heat pump demonstration project in Salt Lake City may bear usefully on the Rush Valley facility. At the historic Downey Mansion on South Temple Street, the owner and City Public Works partnered to introduce use of the sewer line as a heat source/sink, depending on seasonal demand. Supplemented by a 1,700 gallon tank in the basement, the 8,000 sq.ft. facility extracts all of its heating and cooling energy, minus electricity for heat pumps, circulation pumps and fans, from 60 linear feet of jacketed, stainless steel sewer line. This installation voids the necessity of drilling many deep wells, or of installing another sort of heat exchange tubing, any of which would have been impossible on this small site. The sewer lines for the Rush Valley facility are very large, by comparison, possibly offering utility as analogous, but 'scaled-up' applications for this simple but impressive technology.

Cost: Well-coupled heat pump systems have been bid recently in the area at prices competitive with 'conventional' HVAC systems with cooling towers, chillers, VAV boxes and DDC controls. The recently completed Spanish Fork Justice Center required 108 400-feet deep heat exchange wells, winning a competitive bid for heating-cooling.

Intermediate-Temperature Geothermal

Medium temperature geothermal resources are not unusual, though few are more opportune than the Crystal Springs resource that is tapped for the existing Draper Correctional Facility, reportedly producing hot water that would otherwise cost approximately $300,000 per year in fossil fuel costs. The Rush Valley site is not thought to possess medium-temperature geothermal resources of this nature, though deep drilling at significant cost could, theoretically, locate such a resource. This report does not recommend further pursuit of medium-temperature geothermal resources.

Cost: Varies widely, depending on depth, flow rates, water quality, water corrosiveness, environmental impacts, etc.

High-Temperature Geothermal

The Blundell geothermal plant is at a site long known to have significant geothermal potential, and other high temperature resource areas are identified some distance to the west of Rush Valley. No such resource appears to exist in Rush Valley.

Cost: High initial cost, not explored here because of irrelevance. Once source reports approximately $45 million for a one-mW plant, and 0.5% O&M per year (Kaltschmitt, 2007, p. 491); NREL reports 3+ cents/kWhr for operating costs, typically; one of the only renewables capable of 'base-load' dependability; anticipated to descend to near 2 cents/kWhr by 2020 (NREL "Renewable Energy Cost Trends," Energy Analysis Office, 2002, NREL website).

SOLAR-ELECTRIC GENERATION (PV)

Solar radiation conversion to usable electrical energy is a well-developed but costly technology. Solar imagevoltaic technologies offer modular units adaptable to virtually any scale, from power to run an individual traffic management device or remote-site monitoring instrument, on the miniscule end, to utility-scale 'PV farms' at the large end. Few PV installations, however, have been larger than a few hundred kilowatts, or the rare recent multi-megawatt generation facilities. It is not out of the question that the Rush Valley facility could opt for the simplicity of multiple, battery-stored, PV-generated power for high-efficiency emergency/security lighting systems at the perimeter of the correctional facility.

Variations from 'conventional' silicon crystal wafer panels can increase productivity, reduce costs at lower efficiencies, or, for some technologies, significantly increase power productivity. Concentrating and tracking PV can enhance the power yield of PV, but at higher costs. The most promising technology changes involve 'thin-film' PV, applied to metal roofing, flexible roof membranes, panels that can be placed on other building planes, or incorporated into structures erected for other purposes. Although costs are declining rapidly, they are still too high to justify investment in the short term. As price declines continue, regulatory and government incentive programs escalate, and carbon tax effects set in, it is expected that virtually every project will find PV to be among the most appealing 'distributed' technologies. This is not yet the case, except for specific, targeted applications.

Cost: Varies widely, depending on technologies, presently from about 22 cents/kWhr to 30+ cents/kWhr, but the cost is declining rapidly, especially for amorphous-film PV. Flexible membrane systems may be incorporated into roofing at a cost of approximately $7/watt. As a coating on metal, PV-producing films can be applied to metal siding and roofing; and as a film on glass, electrical generation can be incorporated

Figure E.2: Racked/Angled PV Panels

into windows, spandrel panels, skylights or canopies. Building-integrated imagevoltaics (BIPV) will see great increase of use as price declines. At present, however, it would be possible to justify BIPV only if specific security or other high-priority needs were met only by power from this source.

SOLAR-THERMAL HEAT AND ELECTRICITY

Conversion of solar radiation to heating, either of air, water or a storage or energy conversion medium, has been the subject of decades of scientific investigation and unscientific fantasy. Engineering texts and academic treatises occupy tens of feet of shelves in libraries across the globe, most bearing dates within ten years of the early-1970s 'energy crisis.' New titles are rare, but those appearing in listings of Amazon.com and Google are largely focused on solar-thermal and solar-electric energy generation and use. Even the newest studies summarize work done in the 1970s and '80s, surveying the immense variety of technologies and applications explored in those decades.

Rush Valley's solar resource is adequate, though not as spectacularly rich as the desert Southwest, for solar-thermal resource capture. Averaging approximately 1550-1600 btu/day-sq.ft., interpolated from regional data, no specific data are available for the Rush Valley site. Summer peak insolation values are assumed to be approximately 2,500 btu/day-sq.ft., with the advantage of consistently clear skies.

Concentrating Solar-Thermal

Concentrating solar-thermal systems capture solar energy by one or another of many concentrating mechanisms, including reflective mirrors focused on receivers. These receiver devices are typically filled with brine, oils or phase-change substances that are capable of circulating at very high temperatures, thereby transferring most captured heat to steam conversion. Concentrating schemes use various reflective and optical focusing arrangements, some multiplying solar energy by factors of thousands. Solar-thermal parabolic 'trough' concentrating systems, reflective surfaces focused on tubular receivers, have been utilized in large power generation installations in California's Mojave Desert, producing tens of megawatts at the nine 'SEGS' (Solar Electricity Generating Stations) plants. 'Heliostat' generating stations utilize a central receiver on a tower and a radial array of many tracking mirrors, all focused on the receiver to produce very high temperatures for steam and power production. The former of these two schemes, parabolic trough concentrators, could be adapted to relatively small installations, as in Rush Valley, with the objective of producing at least five megawatts during daylight hours.


Figure E.3: Solar-Thermal Parabolic Trough Array

Cost: NREL's Energy Analysis Office estimated the cost in 2002 at approximately 8 cents/kWhr. We must note that this estimate assumed a much larger generating capacity, in excess of 100 mW. Smaller installations cost significantly more per unit of power produced, however, so refinement of concentrating solar-thermal cost projections would be necessary were this technology to be pursued. We further note that the high temperatures can be used not only for electrical generation, but also for space heating through a central plant employing high-temperature/high-pressure water or steam, and can provide heat to greenhouses. Were storage to be engineered into a concentrating solar system, to bridge periods of unproductivity, a robust, appropriately sized system could provide all of the Rush Valley correctional facility's electrical and heat needs, as well as cooling.

Salt Gradient Solar Ponds

Solar ponds may be stable and capable of accumulating solar heat if they are stratified into three zones: dense, saturated salt solution at the bottom, an anti-convective salt gradient zone in the middle that resists overturning by virtue of its density, and a relatively clear zone at the top containing little salt. The anti-convective layer is critical to the function of the salt-gradient solar pond (SGSP). SGSPs are the only form of solar thermal energy receiver capable of storing heat through diurnal cycles, and maintaining heating capacity through cloudy periods lasting as long as several weeks, and functioning through cold winters.

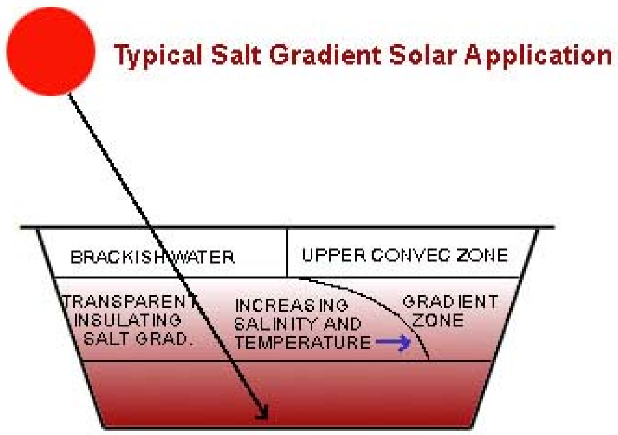

Figure E.4: Salt Gradient Solar Pond Schematic

The ‘lowest tech’ of all solar-thermal mechanisms, SGSPs can dependably produce storage layer temperatures of 170-185^{o} F, in approximately the same temperature range as intermediate geothermal sources like that at the Draper Prison’s Crystal Springs. Heat can be used directly from circulation through exchange tubing in the storage zone; alternatively, heat can be extracted at an engineered rate to an organic rankine cycle engine for electricity generation. A 3,350 m^2 SGSP at the University of Texas-El Paso has been operating reliably since 1986, with the exception of a liner replacement in the 1990s, producing an average of 70 kW-electricity, ranging as high as 100 kW. A 5 mW SGSP complex in Israel operated through the 1980s-early ‘90s until shut down due to corporate ownership changes. Several SGSP installations reportedly provide heat and/or power for desalination, food drying and other industrial, heat-intensive systems, as well as swimming pool heating in a town in Ohio. Recent work on SGSP technology has improved liner membranes, insulation under sidewalls, depth optimization of storage and anti-convective zones, conversion of heat to usable forms without destabilizing the pond, and minimizing of evaporation rates from pond surfaces. Various enhancements have been developed to separate the storage zone from the anti-convective gradient layer. An intensive review of SGSP and heat-exchange technologies is advisable, as well as the involvement of Ormat Technologies, Sparks, NV, the geothermal specialties company that built and operated the world’s largest SGSP plant in Israel.

Service Match with Owner’s Objectives

The critically important service that can be performed by SGSPs is thermal energy storage and the capacity to generate electricity or to yield hot water on demand, at any time of day or year, as long as the system is engineered to anticipate the magnitude of demand. In a image on the UTEP solar pond website, a man stands on an ice layer on top of the SGSP while water in the storage layer remains at 170^{o}+ F, the steady-state operating temperature. SGSPs are extremely versatile and stable, when properly designed, built, established and operated.

The Rush Valley site may be ideal for SGSP development and use. No other area in the world has been as thoroughly studied for its potential for SGSP development as the vicinity of the Great Salt Lake. Density-inducing salts need not consist of NaCl; rather, any set of reasonably transparent salts that are sufficiently dense will work, including sea water and salts from water treatment. The essential prerequisites for SGSPs are water, land and salt. The Rush Valley site possesses adequate open land, and the distance to salt sources at the Great Salt Lake is reasonable, especially for bulk transport by rail. At the power productivity rate of the UTEP example (70 kW$_{el}$, 300 kW$_{th}$) per unit area, a Rush Valley SGSP would need to be at least 75 acres of pond surface to supply 5 mW electricity dependably, allowing for the lesser rate of insolation at the more northerly latitude (40^{o} 22.85’) than El Paso, TX. Allowing sufficient heat exchange for space heating, culinary water and greenhouse heating could require at least 50% additional pond area, and as much as double the size. Infrastructure requirements and area taken up by embankments translate to approximately double the area of pond surface for total footprint; i.e., 75 acres of pond will require at least 150 acres of facility area, or about 3 percent of the selected site area. Land costs and values for other uses are not considered here.

Cost – SGSP Construction and Power Plant: Only a few SGSPs exist, and all are unique. Cost estimates from engineering literature place investment costs for pond and power plant construction at 40 Euros/m^2, approximately \$75/m^2 of pond (approx. \$7.50/sq.ft.). Experience with environmentally critical reservoir and waste containment construction in the Salt Lake area suggests much lower costs for ponds, but the environmental permitting and monitoring systems make it advisable to maintain this budget approximation for the present. (Source: M. Kaltschmitt, W. Streicher and A. Wiese, eds., 2007, pp. 227-8). Cost per electrical productivity unit is another matter. This source estimates a five megawatt SGSP power plant based on European models and pricing, at approximately 58 acres, costing about \$3,750/kW, equivalent to \$18,750,000, with about \$200,000/year operating costs, yielding approximately \$.25/kWhr. We believe this figure to be on the high end of the range of possible costs in Utah, given adequate land, water and proximate salts. In this SGSP-sophisticated location, with great expertise at Utah State University, University of Nevada-Las Vegas, and an engineering community interested in regional renewable energy advantage, the intellectual capacity to arrive at state-of-the-art salt gradient solar pond design can safely be assumed. With fewer moving parts than nearly any other type of solar-thermal system, the SGSP power plant is theoretically simple. Although dozens of SGSPs have been built and operated in the US, Australia, India and elsewhere around the world, often for process heat on poorly-documented industrial sites, the technology warrants refinement and adaptation to locally available conditions and technologies. In addition, the environmental permitting conditions would require exploration for the proposed site.

Solar-Thermal Storage

In addition to capturing, storing and providing heat for direct use and electrical generation, salt-gradient solar ponds can be utilized to store heat from other sources, to a point of system capacity. If heat is generated or recovered, or electricity is generated, at times when not needed within the facility, it is possible to direct heat (converted from electricity if needed) into the storage layer of SGSPs with thermal capacity, then convert this stored heat when needed. Other solar thermal storage mechanisms are being developed, including phase-change substances, fluids other than water, and large masses of solid materials such as concrete with heat-exchange tubing cast in.

BIOMASS CONVERSION TO ENERGY

At first examination, the Rush Valley site appears to be extremely deficient in biomass for potential energy conversion. Situated on the flank of a valley in a Great Basin desert, biological productivity is among the lowest of any area in the US. Most biological resources that could become biomass feedstocks, then, would be imported to the site. The following is a list of possible biomass sources that could be used at the site.

Food waste and sewage sludge from the prison

Each person in the US generates approximately 1.3 pounds/day of sewage sludge. The proposed facility would, therefore, generate at least 7,800 pounds/day, plus staff contribution, of sewage sludge. Food waste would be an undefined quantity, but can be assumed to amount to a similar order of magnitude, measured in tons, as well.

Beyond the organic waste assured to emanate from the correctional facility itself, the other possibilities are conjectural, and matters of choice and of opportunity.

Produce and crops grown on-site

Produce and crops could be grown either in greenhouses or in fields occupying some of the extensive lands of the site. Crops could be food or grain crops, creating byproduct organic waste, or could be dedicated crops grown for their contribution to energy production.

Organic wastes, such as sewage sludge, gathered from surrounding communities

A new wastewater treatment plant in Riverton, soon to be built by the South Valley Sewer District, will initially process 15 million gpd of sewage flows, generating an as-yet undefined quantity of sludge. The District anticipates hauling all sludge to a desert location, now under negotiation, for land disposal. The facility expects to double in capacity within ten years, to 30 million gpd.

Landscaping waste and forest thinning ‘slash’ that is cellulosic in nature

An unusual opportunity may present itself in a Salt Lake County initiative to remove invasive Russian olive trees from the Jordan River area. Were there to be a means of inexpensive disposal, as an alternative to landfill composting, this program could produce an ongoing flow of woody materials. Pine bark beetle killed trees continue to plague regional forests, creating enormous fire hazards. Thinning and selective removal of beetle-killed trees is being used in Nevada at a correctional facility as fuel for efficient boilers, as could be done at this location, given favorable transport arrangements.

Municipal Solid Waste

Municipal solid waste could be separated for materials suitable for conversion to energy, with appropriate concern for types of materials that are appropriate for different types of energy conversion.

Within these possible feedstocks are many different types of organic materials, each of which must be evaluated for its best possible utility and matched with the appropriate technology to convert it to energy and, in some cases, to additionally useful materials.

Anaerobic digestion for gas production

Sewage sludge, food wastes and other wet wastes, such as animal manure and some crop wastes, are candidates for anaerobic digestion to produce methane gas and a rich nutrient residue best utilized in a compost for soil enrichment. Operators of an anaerobic digester, which cultivates colonies of methane-generating bacteria under ideal conditions in a thermally controlled vessel, can control odor more readily than most other processes. The methane produced can be further refined, to increase fuel values, or can be used as produced for heating, cooking or firing emergency generators. Anaerobic digestion gas can also be used to drive electricity generators, which allow opportunity to capture waste heat for direct use, as well, often in maintaining conditions for digester operation.

Landfilling for gas production

Landfilling is a crude but effective way to produce a mixed ‘biogas’ with sufficient fuel values to use for running generators, heating greenhouses, or other

Figure E.5: Anaerobic Disgester – UC Davis applications similar to digester gas. A landfill used for gas production must be constructed with that objective, from the outset. A portion of municipal solid waste could be landfilled, while some portion can be treated as cellulosic waste.

Cellulosic pellets

Cellulosic (woody) waste can be chipped, pelletized or formed into briquettes, in addition to logs, for combustion in efficient boilers, used in cogeneration systems. Wood can also be gasified (heated in absence of oxygen) to produce 'syngas,' which can be cooled, cleaned and used as a natural gas equivalent for heating, electricity generation or for driving emergency generators. Many crop wastes can be included in this feedstock, such as straw, grasses, and dedicated woody crops.

Biodiesel

Oil crops, such as soybeans or rapeseed (canola oil), can be feedstocks for biodiesel production. It is doubtful that this facility would be able to justify building a large biodiesel conversion plant, but given the probable quantities of waste cooking oils that will be available, a small biodiesel facility may be worthy of consideration.

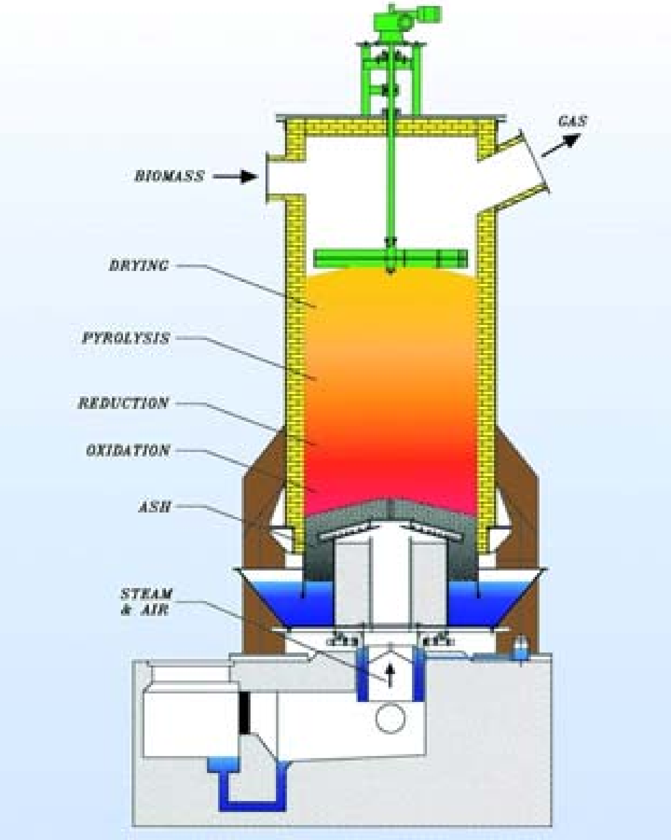

Figure E.6: Biomass Gasifier Schematic Section – WorldChanging.com

***Cost**:* Biomass energy conversion varies from quite low for *landfill gas* capture and utilization—essentially the cost of the landfill plus additional liner covers and gas-capture vents, as well as electrical generators, boilers or other systems necessary to use biogas. *Anaerobic digestion* costs can be extrapolated from US Department of Agriculture systems for dairy and feedlot manure digestion systems, which cost a minimum of about $1.0 million to construct, upward based on flow rates. It is likely that a combined objective of gas production with nutrient recovery would dictate 'batch' reactors, built at lower cost in multiples, to allow simultaneous operation in parallel. *Cellulosic materials* fed to efficient boilers are reasonable for use in one or more central plant facilities within the complex, sized to meet the need of facilities served, plus cogeneration to convert to electricity the heat available in off-peak intervals. *Cogeneration* is addressed elsewhere in the present report, a versatile technology lending itself to combination with many other heat-producing energy technologies. *Gasifiers*, depending on scale of feedstock available, are expensive and relatively new to the area. At least one area company, Emery Energy Company, has been developing gasifiers for several years to convert various coal, tire and wood wastes to energy. Common in Europe and Asia, gasification is anticipated to become an increasingly important utility-scale and 'distributed' industrial heat and electricity source. Biodiesel manufacturing is an expensive capital investment for commercial-scale production. At smaller, facility use scale, however, it may be worth further investigation for generator use or for transportation, probably mixed with conventional diesel to avoid coagulation problems in cold weather.

***Further Evaluation**:* Of the various biomass energy recovery possibilities, anaerobic digestion seems most promising as a match for facility needs, possibly in combination with solar-thermal heat to help maintain methane generating bacterial cultures in ideal conditions. A point of further investigation is the possibility of hybrid systems of this sort, combining waste feedstocks with fossil fuel supplies such as natural gas to help defray fuel costs, transition into autonomous energy supply, and to improve the overall energy sustainability of the facility.

HYDRO-POWER

As stated earlier, little or no ‘run of stream’ hydropower potential exists at the Rush Valley site. Slope is relatively gentle from east to west, but the hydrological setting contains no perennial streams. Although topographic relief is 414 vertical feet in approximately 3.5 miles, no natural basins exist that could be converted to use even in a pumped-hydro generation scheme. Any hydropower utilized at the site will have to be engineered.

Micro-Hydro Turbines

According to preliminary utility layouts, facility source water wells will be drilled high on the site, approximately at elevation 5,500’, near large (750,000 gallons each) water tanks. Water lines will parallel the road that bisects the site down to the men’s and women’s compounds, a drop of nearly 200’ vertically in approximately one mile. Wastewater treatment will occur near the women’s compound, possibly feeding downhill further to a retention pond about elevation 5,240’, providing head pressure to irrigated crop areas at the west extent of the site around 5060-5140’ elevation. Each of the elevation drops may afford opportunity to capture some of the energy latent in the vertical fall. This energy capture would need to be designed into the water line from the beginning to maintain water pressure throughout, while extracting energy at optimum rates. Costs are impossible to estimate without further design refinement, but are thought to be on the order of a few hundreds of thousands for a robust system, with relatively rapid payback from production of tens of kW of relatively dependable power.

Pumped Hydropower and Hydro Storage

By releasing water from an elevated reservoir through generators, one can generate electrical power more or less at will, seizing opportunity to create power when it is most urgently needed within the facility or when it is of greatest value if sold to the utility grid. If that water flows on to a lower reservoir where it is held, then pumps may be reversed to lift the water back into the upper reservoir. In this model, ‘baseload’ power, which is the least expensive from the grid, or wind or another intermittent form of renewable energy, is used to do the lifting. More energy is expended than would be the case with a simple gravity hydropower system, so the scheme cannot be characterized as ‘renewable.’ If, however, a pumped-hydropower scheme makes economically feasible the installation of wind, solar or an intermittent renewable energy type, and adds either functional utility or economic value to consumed or exported power, then the system may justify the increased investment.

***Costs and Benefits**:* For the Rush Valley site, any pumped hydro system physically possible within the boundaries of the site would be small, of necessity. It is likely that a Kaplan turbine, into which water flows axially, would be used. This is the type preferred for low-head systems. It is not out of the question that reservoirs could be enlarged at the top end of the system to be made sufficiently large to supply both culinary needs and needs for power generation. Investment and permitting challenges, however, would escalate dramatically. The matching of energy supply with facility energy needs, especially for adaptability and independence from the utility grid, would be very beneficial. Overall sustainability, given sufficiently robust power generation from wind, solar-thermal or other intermittent power sources, can be significantly enhanced by the quick-response, versatility and ‘leveling’ capacity of pumped hydropower through balancing of supply and demand. Beyond immediate facility needs, the enhanced value of strategically generated power can be “cashed in” by sale of peak power to the grid—or could be, were this advantage to be allowed under utility regulations. This may come to be the case in the future, but it is not at present. For now, market “firming” of wind power as a justification for pumped storage, other than large scale projects, is probably not worth the investment. Energy storage for facility use, however, may reduce to a comparison between salt gradient solar ponds, a biomass conversion technology that can produce a storable gas or liquid fuel coupled with rapid-response power generation (e.g., biodiesel or methane), and a restrained-scale version of pumped storage hydro power. Storage may also be effectively accomplished by oversizing generation of any robust renewable resource/technology pairing, relying on the utility grid instead of storage, selling excess power to the grid, but diverting to facility needs when required.

OTHER ALTERNATIVE ENERGIES AND FUTURE POSSIBILITIES

Energy systems are advancing in technologies and the ways they are assembled into facilities of all sorts. Any new or significantly remodeled building or set of buildings created now should anticipate the possibility of incorporating new and future technologies. 'Distributed' and 'district' energy generation will afford opportunities for facilities to 'go off-grid' to a great extent, and utility grids must respond with the flexibility to supply sudden loads that occur when these nearly independent subsystems fail. A carbon tax and other fiscal policy and regulatory measures seem imminent, to shift the energy mix toward a new balance including more renewables and efficiency. As these changes settle into the American economy, advanced but underutilized technologies, along with new, "smart" controls, will match more precisely supply with demand after significant reductions in demand through integrative, whole-building design. Whole communities—campuses, neighborhoods, industrial complexes, and city cores—will become coordinated and integrated for energy efficiency, creating economies of scale that have not existed before for renewable energy and efficiencies. Precedents have existed, ones that were efficient and effective: Steam and high-temperature water flowed through pipes in dozens of downtown city districts, including Salt Lake City. Some high-temperature water systems (approximately 400^o F and 400 p.s.i. pressure) still are vital systems on university campuses and military bases, as at the University of Utah and Hill AFB. Models such as industrial ecology-based 'eco-industrial parks,' which emphasize shared high expectations for energy and water efficiency, and for environmental performance, may become more appealing to business, institutions and governments at all levels. Need for economic development will likely encourage policy changes toward energy efficiency and renewables, and will reward less dependence on fossil fuels.

Efficiency – Controls, Lighting and 'Smart'-Tech

Significant advances are occurring in buildings and building systems. Lighting and lighting controls are on the verge of ascending the efficiency ladder from less than 50% efficiency toward 90% or more. Many devices that have been available for years, but that have been expensive enough to discourage use, are becoming not only affordable but also among the best ways to achieve credible reductions in fossil fuel energy consumption, as well as compliance with sustainable design/building standards. New applications of the most sophisticated computerized 'building intelligence' systems can read instruments installed throughout a facility and its environmental controls systems, learning from the data it acquires to create leaps in efficiencies (e.g., www.richards-zeta.com).

Cutting-Edge Renewables

As prices continue to decline, materials are improved, and microprocessor technologies accelerate in their applications to energy management, efficiency and renewables, changes in energy use, generation and distribution are inevitable. Among the most conspicuous of these changes that are foreseeable are the following:

- ***Building-Integrated Renewables and 'Smart' Environmental Controls:*** Imagevoltaic electrical generation will be integrated into roofs, walls, canopies, glazing systems and many other building components. Automated solar energy control of skylights and other daylighting devices will respond to sunlight to achieve owner-preferred preset levels.
- ***Low-Velocity Wind Generation:*** Small, high-efficiency wind generators are in development for installation on building parapets, in exposed walls and on low-elevation towers to capture wind energy at otherwise marginal locations. This development is expected to change the patterns of wind generation, making distributed renewable energy more accessible.
- ***Low-Cost PV:*** Utility-scale imagevoltaic panels are expected to decline in price from current $.22/kWhr to $.10 and beyond over the next 15-25 years. As carbon tax impacts level costs between fossil fuels and renewables, PV will assume more of the market at favorable locations, such as Rush Valley.
- ***Updraft Power Towers:*** Testing of relatively futuristic ideas such as 'updraft power towers' for electrical generation will be resumed. Pilot projects were built in the 1980s, but were neglected as energy concerns declined. Extremely tall convection towers sit in the midst of im-

mense, transparent canopies at the base. Solar heat warms the ground beneath the canopy, which can be kilometers in diameter, inducing convective updrafts in the tower, drawing artificial winds through a circle of wind turbines at the tower's base, or through a single large turbine high in the tower. Although early studies have envisioned solar updraft power towers of far larger sizes to produce hundreds of megawatts, it is projected that installations can be sized to fit relatively limited, 'distributed energy' scale needs of facilities such as the Rush Valley Correctional Facility, generating as little as 5 mW. Investments are high—according to NREL, approximately $50 million for a 5 mW generating station—but efficiencies are also high, storage mechanisms are possible, and the enormous area under the greenhouse-like canopy can become an intensive food-producing or energy crop zone. Designs have been drafted utilizing ponds and fish-farms, as well as algae cultivation for energy and food in these ponds.

- ***Stirling Engines**:* Nearly 200 years old, Stirling engines are external combustion engines that are efficient and promising, utilizing nearly any external heat source. 'Dish Stirling' systems use parabolic reflectors to focus solar heat on a receiver, providing high temperatures to drive a Stirling engine linked electrical generator. Other Stirling engines in development are propelled by natural gas, hydrogen, biomass and nearly anything else that will produce heat. As a technology that is very conducive to modularization, Stirling engines promise high efficiency for remote-site and residential applications. One such application might be a unit of perimeter security lighting for the Rush Valley facility, as units are packaged and well serviced in the marketplace.
- ***Fuel Cells**:* Addressed elsewhere in this report, fuel cells can be fueled by a wide variety of gases, depending on fuel cell type. Hydrogen-fueled units produce literally no pollution, though the problem of production of hydrogen is by no means solved. Those likely to enter the building energy market are natural gas fueled, still producing extremely little pollution.

Figure E.7: 'Dish Stirling' Engine

Storage, ‘Firming’ Renewables and Load Control

Intermittent renewable energy producers, such as wind, PV and solar-thermal other than salt gradient solar ponds, present a problem of assuring that energy is available and reliable as needed. The critical nature of security in the proposed correctional facility shifts the range of choices toward those energy possibilities offering storage either as an attribute of in combination with another technology that performs this service. Energy storage coupled with quick-start generation offers the assurance that power will be there when needed, and that costly ‘peak’ episodes can be avoided.

GE WPT ZENON Proposal #60806.1

Proposal for a Z-MOD™–*L* Wastewater Treatment System

(.6 MGD)

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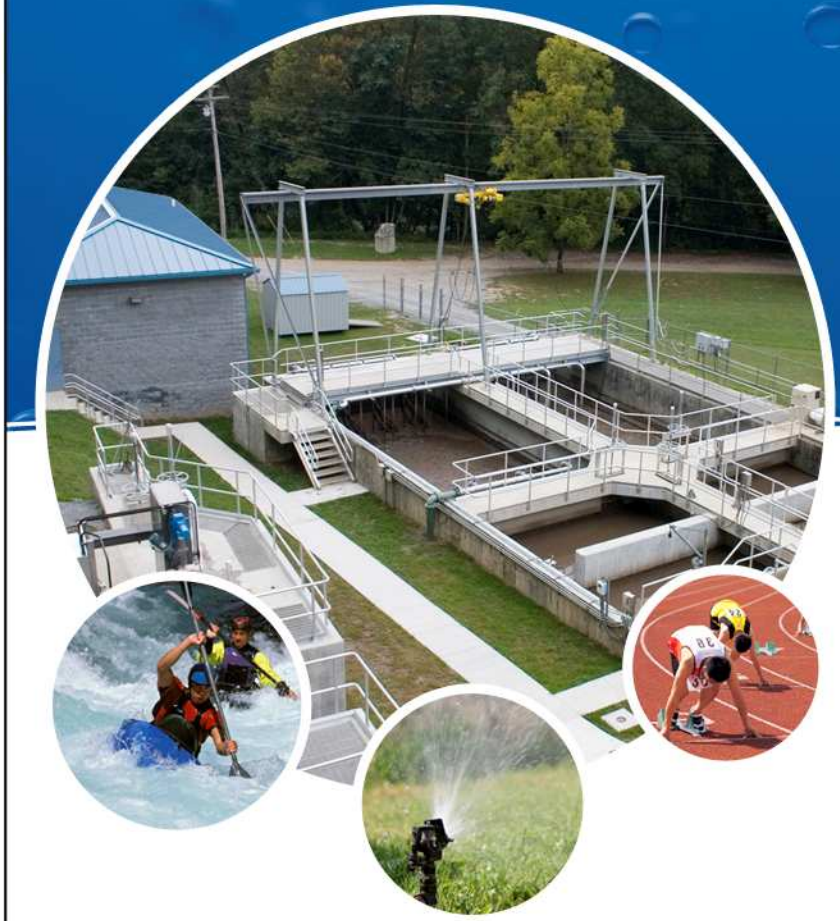

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1.0 SYSTEM OVERVIEW

1.1 The ZENON Advantage

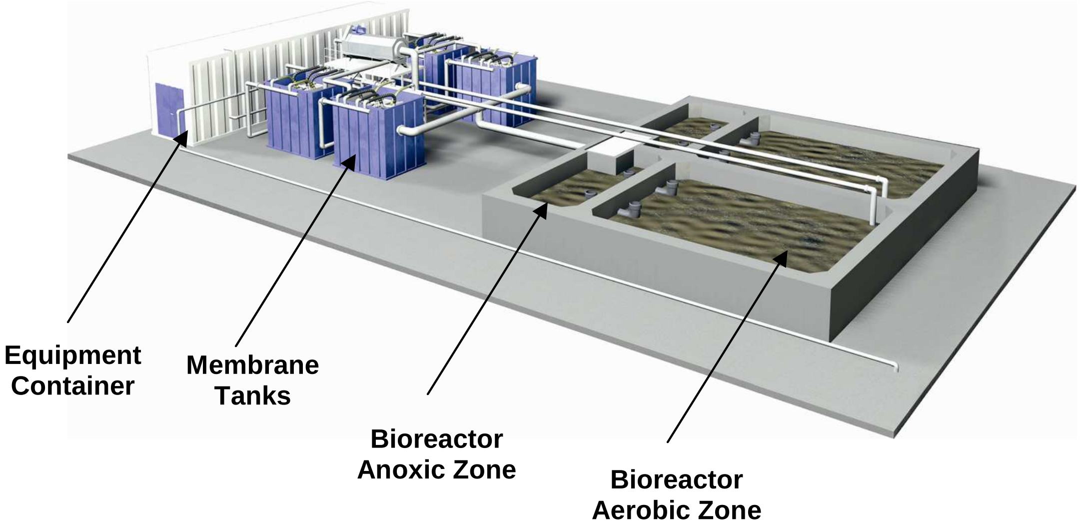
Z-MOD™–*L* Packaged Plants are pre-engineered, modular wastewater treatment systems that bring proven ZeeWeed® membrane bioreactor (MBR) technology to municipal, industrial, or land development applications. Incorporating an expandable building-block design, Z-MOD™ Package Plants can be quickly set up in virtually any location and feature scalable treatment capacity that can be quickly increased as demand grows. These plug-and-play ultrafiltration (UF) systems outperform conventional treatment alternatives in all categories, offering reduced operating costs, smaller plant footprints, more reliable performance, and high quality effluent that meets or exceeds the world's most stringent discharge and reuse standards.

Z-MOD™ packaged plants bring the proven large-plant features and performance of ZeeWeed® membranes to compact, pre-engineered wastewater treatment systems.

Z-MOD™–*L* produces superior quality effluent through an innovative combination of immersed, low-pressure ZENON ZeeWeed® ultrafiltration membranes and a suspended growth biological reactor. ZeeWeed® UF membranes replace the solids separation function of secondary clarifiers and the polishing function of granular filter media that are found in conventional activated sludge systems. By eliminating the need for sludge settling, the Z-MOD™ MBR process can operate at mixed liquor suspended solids (MLSS) concentrations in the range of 10,000 to 15,000 mg/L—three to five times greater than conventional systems, resulting in plants that are significantly more compact than a conventional plant.

Fewer processes, combined with highly automated, PLC operation makes plant operation less labor intensive and much more straightforward. Plant operators are only required to perform regular preventive maintenance on system pumps, blowers, and associated mechanical equipment to ensure efficient biological processes and optimum membrane permeation.

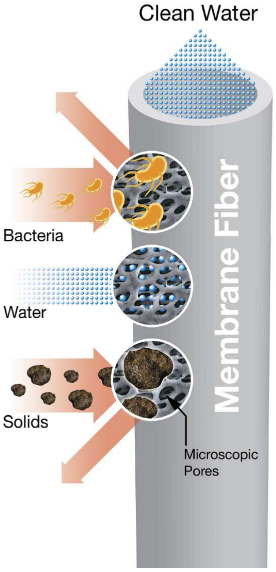
Figure 1: Z-MOD™–*L* Configuration



At the core of the Z-MOD™–*L* is the ZeeWeed® 500 reinforced hollow fiber membranes—the industry's leading choice for long-life and high performance in the harsh, high-solids environment of a bioreactor. The rugged fibers are held in large modular cassettes that are immersed directly into the bioreactor. With nominal and absolute pore sizes of 0.04 microns and 0.1 microns respectively, ZeeWeed® 500 virtually ensures a particulate-free effluent.

Each cassette has a permeate header that is connected to the suction side of a reversible rotary lobe pump, which applies a low-pressure vacuum to draw treated effluent through the microscopic pores of the fibers in an outside-in flowpath. This method of permeation minimizes energy demands and prevents particles from fouling and plugging the inside of the membrane fiber.

ZeeWeed® UF membranes operate under a low-pressure vacuum, drawing clean water to the inside of the fiber (outside-in flow path), while leaving impurities in the process tank.



Outside-in permeation also simplifies membrane cleaning an maintenance, enabling a continuous stream of coarse bubbles to rise vertically along the length of the membrane to scour rejected solids away from the membrane surface. Periodically, the permeate flow is automatically reversed to backflush solids that have accumulated in the membrane pores. When necessary, in-tank chemical recovery cleanings can restore membrane permeability to optimum levels.

The modular membrane cassettes are designed to provide a great deal of flexibility in system design. The membrane cassettes are immersed into stainless steel tanks tanks supplied by ZENON, or concrete tanks supplied by the buyer.

ZeeWeed® 500 is the membrane of choice for strict nitrogen and phosphorous discharge limits. Typically, the lead end of the bioreactor is designed as an anoxic (zero dissolved oxygen) zone. This is used to assist with pH control in standard systems and for denitrification in applications where extremely low levels of total nitrogen (TN) are required in the effluent stream.

The process may be easily enhanced for significant phosphorus reduction by adding a metal salt, such as ferric chloride or alum. As the Z-MOD™ MBR process does not rely on settling for solid reduction, a minimal volume of metal salts is needed to create a "pin-floc". The membrane then effectively blocks the microscopic floc from entering the effluent stream resulting in phosphorous levels typically below 0.1 mg/L.

2.0 SYSTEM DESCRIPTION

2.1 Design Criteria

The Z-MOD™–*L* system is designed to treat an average daily flow (ADF) of .6 MGD. The system can support a Maximum Daily Flow (MDF) of 1.2 MGD for periods generally not exceeding 24 continuous hours. Any flow conditions greater than the above-noted flow limits must be equalized prior to treatment in the membrane bioreactor unit.

The following table summarizes the main design parameters on which the Z-MOD™–*L* MBR system has been designed. The column titled "influent" is typical of medium strength sanitary wastewater – to be approved by the client. The column titled "effluent" is the anticipated treated water quality that the Z-MOD™–*L* can achieve based on current ZENON design.

Table 1 Design Parameters

Parameter	Influent	Effluent	Units
ADF	.6	.6	MGD
MDF(1)	1.2	1.2	MGD
Design Water Temperature	10 ℃	10 ℃	°C
BOD_5	250	<5	mg/L
TSS	40	<5	mg/L
Alkalinity(2)	n.a.	n.a.	mg/L
Turbidity	n.a.	< 1	NTU
TN(4)	20	<10	mg/L
TP	6	1(5)	mg/L
TKN	30	<3	mg/L
E coli (3)	n.a.	< 2.2	cfu/100 ml

Note(1): Maximum daily flow can generally be maintained for periods not exceeding 24 consecutive hours.

Note(2): ZENON is assuming that sufficient influent alkalinity is available to ensure proper performance of the biological system. If influent alkalinity level is not sufficient, chemical addition will be required. ZENON has added a NaOH dosing system for this purpose in its scope of supply.

Note(3): With the use of UV or Ozone post disinfection.

Note (4): TN less then 10mg/L corresponds to minimum design temperatures of 10C.

Note (5): Effluent phosphorus at this level will require the addition of ferric chloride. Since this may not be a requirement, we are offering this as an option with a price adder in the pricing section.

2.2 Standard ZENON Supplied Equipment

The Z-MOD™–*L* MBR is a modular, system designed for rapid, plug-and-play installation. Pre-assembled components include the permeate and control panel skid, membrane cassette assemblies (with air and permeate headers), and chemical addition system skids. Items that will be shipped loose for installation by OTHERS include the backpulse tank, blowers, submersible pumps and other equipment.

2.2.1 Control Equipment

A KOYO Programmable Logic Controller (PLC) with a Human Machine Interface (HMI) , installed in the main NEMA 12 control panel, monitors and manages all critical process operations.

Level controls monitor the level of mixed liquor in the process tanks and transmit this information to the Z-MOD™ PLC. The PLC will automatically adjust the flow of the ZMOD trains based on proportional control to the process tank levels in order to minimize the instantaneous flux of the membranes.

During an influent surge, the permeate pump will enable the system to handle up to twice the ADF for a period not to exceed 24 consecutive hours.

In the event of a system or equipment problem requiring operator attention, the PLC can either alert the operator or shut the system down.

The control panel includes all motor control hardware for the ZENON

2.2.2 Membranes

The membrane modules are assembled into cassettes. Cassettes are installed in steel tanks or, alternatively, in a membrane section part of the bioreactor. Tanks to be supplied by others.

Table 2 Membranes are ZENON ZeeWeed® 500 modules

Item	Qty	Description
Membrane Modules	192	ZeeWeed® 500d membrane modules
Membrane Cassettes	4	48 – Module Cassette
Membrane Trains	2	

2.2.3 Permeate and Backpulse Pump Equipment

One permeate pump for each train is employed to draw water through the membranes. The two permeate pumps, associated valves and piping for the dual train system are mounted on a factory assembled, epoxy-coated carbon steel skid. Treated water flows from the permeate skid to the final disposal point.

The reversible rotary lobe pumps will reverse the flow of permeate through the membrane tanks during Backpulse sequences. Under normal operation, backpulsing is changed to a "relax" mode on regular intervals. Unless specific operating environments necessitate the ongoing use of backpulsing, the relax mode helps maintain the time period between cleans, and eliminates electrical costs of backpulsing. Permeate pumps are selected to optimize efficiency within their design parameters.

2.2.4 Membrane Scour Aeration System

One standby and one operating membrane aeration blowers are included to provide membrane air scouring during membrane cleaning. Associated piping and valves are included.

2.2.5 Sludge Wasting System

Sludge wasting is accomplished by periodically diverting mixed liquor from the recirculation line, via manual control. The frequency of wasting is a function of influent characteristics, reactor design and operator preference. Typically, mixed liquor wasting may be performed monthly, or over significantly longer periods.

2.3 Additional Process Equipment

Additional process equipment may be required for the process. Details are listed below. The following equipment may be provided by ZENON.

2.3.1 Pre-treatment and Screening

Trash and non-biodegradable solids, such as hair, lint, grit and plastics may foul or damage the membranes if allowed to pass into the membrane chamber.

To enhance the long-term operation and effectiveness of the treatment system Zenon recommends;

An internally-fed screen with mesh or punched-hole opening less than or equal to 2 mm with no possibility of bypass or carryover.

For full redundancy, duty and standby screens can be installed.

2.3.2 Equalization Tank

Equalization is required for any system with variable flow rates. If an equalization tank is not used then adequate volume must be available in the process tank. ZENON does not supply equalization tanks. A minimum equalization capacity of 12 to 24 hours is recommended.

2.3.3 Equalization Tank Transfer Pump

Transfer pumps transport wastewater from the equalization tank to the process tank. The transfer pumps are automatically activated by the PLC according to the level controls in the equalization tank.

2.3.4 Bioreactor

There are 2 bioreactors for this project supplied by the client consisting of aerobic and anoxic zones.

Table 3 Estimated Bioreactor Characteristics

Parameter	Value	Units
Average Daily Flow (ADF)	.6	MGD
Maximum Daily Flow (MDF)	1.2	MGD
Design HRT	6	hours
Anoxic Volume Required	142,080	USgal
Aerobic Volume Required	199,920	USgal
Total Reactor Volume Required	342,000	USgal
Minimum Water Depth	12	ft
No. of Bioreactor Tanks	2	Tank
Design MLSS	10-15,000	mg/L

Note: Tank sizing is a preliminary suggestion only and may change once final detail design commences.

2.3.5 Process Aeration System

The process aeration blowers provide air for the biological tank and ensure that sufficient oxygen is available to maintain the biological processes in the tank.
If provided by ZENON, the process aeration blowers are shipped loose for installation on site and are redundant at average air requirements.

2.3.6 Fine Bubble Diffusers

A fine bubble diffused aeration system delivers air from the aeration blowers to the aerobic zone of the process tank. ZENON supplies high efficiency diffusers that can operate with smaller aeration blowers, thus reducing operating costs.

2.3.7 Process Mixers

Process mixers can be provided to mix the anoxic chamber and prevent solids from settling in the anoxic chamber.

2.3.8 Low TN Recirculation Equipment

Supplementary recirculation is necessary in cases where low effluent concentrations of TN are required. The mixed liquor recirculation system transfers mixed liquor from the aerobic chamber to the anoxic chamber of the process tank. A standby and operating submersible pump system with associated piping is included to recirculate at 5 x ADF.

2.3.9 Process Tank Transfer Pump

The transfer pumps are used to transfer mixed liquor from the bioreactor to the membrane tank at a rate of 5 x ADF. The sludge returns to the anoxic zone of the bioreactor using gravity at a rate of 4 x ADF.

The sludge circulation moves accumulated solids away from the membranes and develops a more uniform mixture in the bioreactor.

2.3.10 Chemical Addition

2.3.10.1 Sodium Hypochlorite Dosing

The Sodium Hypochlorite Dosing system is used during cleaning process to eliminate organic fouling on the membrane surface.

2.3.10.2 Citric Acid Dosing

The Citric Acid Dosing system is used during cleaning process to eliminate inorganic scaling on the membrane surface.

2.3.11 Effluent Flow Measurement

An optional effluent flow meter can provide daily discharge flow measurements.

2.3.12 Effluent Turbidity Analyzer

An optional effluent turbidity analyzer can monitor effluent water quality and alert operators if effluent turbidity rises beyond acceptable parameters.

2.3.13 Effluent Disinfection Optional

Optional ultraviolet disinfection can be configured to meet peak flows with no redundancy or be equipped with redundant components to meet average daily flow.

2.3.14 ZenoTrac™ Optional

ZenoTrac™ is a powerful plant process support tool that provides fully automated process data monitoring and trend analysis. The system stores field-acquired and calculated values in a central database and provides reports via e-mail, web site or printed documents. ZenoTrac™ helps operators to quickly view trends, improve productivity and optimize processes.

2.3.15 Membrane Cleaning

Air scouring and backpulsing are the day-to-day methods used to maintain membrane flux∗. Over longer periods of time, the membranes can experience fouling caused by the inevitable accumulation of organic matter or crystallized salts within the membrane fiber pores. On these occasions, the ZeeWeed® membranes may require cleaning to restore permeability.

Maintenance cleans are automatically used at regular intervals to backpulse chlorinated solution 2 to 3 times per week.

Recovery cleaning may be required periodically where the membranes soak in a cleaning solution for a period of 8-12 hours. The frequency of recovery cleaning is site-specific, but typically occurs every six months.

Sodium hypochlorite is used to oxidize organic foulants and citric acid to remove inorganic scaling. With bioreactor mounted cassettes, in-situ cleaning can be done provided that the membrane tank can be isolated from the bioreactor. ZENON can provide the necessary design guidelines during detailed engineering.

“Flux” is defined at the amount of water that can pass through a given surface area of membrane. The cleaner a membrane and the warmer the water, the higher its flux will be.

Typical Equipment Selection

Table 4 ZENON supplied equipment

Equipment	Supplier
Membrane Modules	ZENON
Instrument air compressor and dryer	Quincy
Permeate pump	Boerger
Skid mounted reversible permeate pumps complete with valves and associated piping	Assembled by ZENON
Membrane air scour & process air blowers	Kaeser
Flow meter, magnetic	Endress & Hauser
Pressure transmitter	Endress & Hauser
Pressure level transmitter	Endress & Hauser
Pressure regulator	Watts Fluidair
Level switches	Signal Master

Pressure indicators	Ashcroft
Temperature indicator	Ashcroft
Automatic valves (3” and above)	Keystone
Ball valves – stainless steel	Pinacle
Ball valves – PVC	Chemline
Diaphragm valves	Chemline
Butterfly valves (3” and above)	Keystone
PVC Ball Check valves	Chemline
Storage tanks	Aco-Equipment
Chemical dosing pumps	Prominent
Recirculation pumps	ABS
HMI	Automaton Direct EZ Touch
PLC	Koyo DirectLogic

3.0 SUPPORT SERVICES

3.1 Business Hours – Technical Support

For the life of the system, Plant Operators have telephone access to a skilled ZENON technical support specialist to assist in troubleshooting system problems. Technical support specialists are available during normal working hours from 8:30 a.m. to 5:00 p.m. (Eastern Time Zone, GMT -5:00). Plant Operators call 905-465-3030 and ask for Technical Support or for Ext. 3406, 3426, 3479 or 3499.

3.2 After Hours – 24/7 Emergency Telephone Support

The ZENON technical support team is always on call and can quickly access a client's system information. Each on-call Technical Support Specialist is equipped with a laptop computer to remotely connect with the plant control system (if so equipped) and gain a better understanding of the situation and make any necessary adjustments to set points or software. The group also maintains its own dedicated hard copy of all plant drawings for reference during support calls.

This allows Plant Operators to contact a knowledgeable ZENON representative in the event of any emergency condition, potentially averting loss of plant production and expensive call outs. Call 905-333-8057 and provide the Plant Access Code to access this service.

Should the situation require a more detailed investigation of control code, ZENON maintains an on-call programmer at all times. Process Support engineers are pulled in as required to resolve the more difficult process issues.

Calls of a non-urgent nature are to be made during the period 8:30 am to 5:00 pm. (Eastern Time Zone GMT -5:00). Not all issues can be resolved through telephone support. In the event that the ZENON Technical Support Group cannot resolve the problem by telephone, Field Service is available at the rates and under the conditions published in ZENON's Field Service Labor Rate sheet.

4.-1 SCOPE OF SUPPLY

4.1 Scope of Supply - ZENON

Table 5 System Equipment incl.

Qty	Item	Price
1	Z-MOD™-L192D unit, fully assembled with 192 membrane modules for a capacity of .6 MGD.	USD $ 1,110,000
Scope of Supply		
1	Aeration Equipment - (1) Standby and (1) Operating Blower for membrane and aeration. Includes piping, pressure gauge, low flow switch and associated valving	
1	Membrane Equipment - Zeeweed Membranes, cassette hardware, piping and associated valving	
1	Recirculation Equipment - Mixed liquor recirculates at 4xADF from the membrane chamber to the aerobic chamber via gravity	
1	Permeate Equipment - (1) Standby and (1) Operating reversible rotary lobe pump with VFDs, (2) pressure transmitters, piping and associated valving (Skid Mounted)	
1	Backpulse Equipment - Pumps included in Permeate Equipment. Backpulse Tank, Tank level control, piping and associated valving included	
1	System Hardware - Koyo PLC, HMI, Control Panel and MCC included	
1	Effluent Turbidity Meter - Turbidity meter including isolation valves, throttle valve and backplate.	
1	Process Aeration Diffusers - SS Aeration Diffusers and Piping as required by process kinetics.	
1	Process Mixer - (1) Mechanical Mixer use to mix the anoxic chamber continuously	
1	Citric Systems - Includes dosing pump, storage tank, tank tray, tank mixer, associated valving	
1	NaOCl Systems - Includes dosing pump, storage tank, tank tray and associated valving.	
1	Process Aeration Blower - (1) Standby and (1) Operating Blower that provides aeration for the process tank with enclosure	
1	Transfer Pump - Submersible Pump used to transfer mixed liquor from the process tank to the membrane tanks. The system includes two pumps sized for 5xADF with check valves, isolation valves, level switches and guide rail assemblies.	
	OPTIONS	
	Adder of phosphorus removal	+ $ 3,500

* Additional man-hours will be billed separately from the proposed system capital cost at a rate of $950 US per day plus living and traveling expenses. Detailed ZENON Environmental Inc. service rates are available upon request.

Equipment delivery is FCA Oakville, ON.

4.2 Scope of Supply – Others

The following items are for supply by OTHERS and will include, but are not limited to:

- Overall plant design responsibility;
- Review and approval of design parameters related to the membrane separation system;
- Review and approval of ZENON-supplied equipment drawings and specifications;
- Detail drawings of all termination points where ZENON equipment or materials tie into equipment or materials supplied by others;
- Equipment foundations, civil work, equipment mounting pads, buildings etc.;
- Receiving, unloading and safe storage of ZENON-supplied equipment at site until ready for installation;
- HVAC equipment design, specifications and installation (where applicable);
- UPS, Power Conditioner, Emergency power supply and specification (where applicable);
- 1 to 2 mm Pretreatment fine screen – as described above;
- Equalization tank – as described above;
- Membrane Tank
- Bioreactor tank – complete with anoxic and aerobic zones;
- Treated water storage tank – as required;
- Process and utilities piping, pipe supports, hangers, valves etc. including but not limited to:
- Piping, pipe supports and valves between ZENON-supplied equipment and other plant process equipment;
- Piping between any loose-supplied ZENON equipment;
- Process tank aeration system air piping, equalization tank system piping, etc;
- Electrical wiring, conduit and other appurtenances required to provide power connections as required from the electrical power source to the ZENON control panel and from the control panel to any electrical equipment, pump motors and instruments external to the ZENON-supplied enclosure;
- All bolts, brackets and fasteners to install ZENON-supplied equipment;
- Raw materials, chemicals, and utilities during equipment start-up and operation;
- Disposal of Initial Start-up wastewater and associated chemicals;

4.3 Validity

The prices quoted in this proposal are for budgetary purposes only. Pricing is valid for 30 days, period after which they may be subject to change.

All orders are subject to review and acceptance by ZENON Environmental Inc.

4.4 Freight, Taxes and Duties

All pricing is FCA Oakville, ON. No freight, taxes or duties are included in the above-noted pricing. All freight, taxes and duties are for the account of the purchaser, or will be invoiced by ZENON at cost plus 15%.

4.5 Terms of Payment

The budget pricing quoted in this proposal is based on the following terms of payment, payable through an irrevocable letter of credit drawn on a Canadian Bank, all banking charges being to the account of the Buyer:

- 15% with Purchase Order
- 30% on submission of General Arrangement Drawings
- 50% on notification that equipment is ready to ship
- 5% within thirty (30) days of equipment start-up or within sixty (60) days of equipment shipment, whichever is sooner

4.6 Typical Schedule

A typical drawing submission and equipment shipment schedule is indicated below. Drawing submission milestones and equipment shipment periods are quoted from date of receipt of a formal signed purchase order:

Submission of P&ID, Bill of Materials, General layout	**4 to 6 weeks after acceptance of a Purchase Order by ZENON**
Drawing Approval	To be determined
Equipment Shipment	20 weeks from release of client approved drawing package(1)
Plant Operation Manuals	2 weeks after shipment of equipment to site
Operator Training	When preferred by Client but no later than 2 weeks prior to the scheduled plant start-up

Note(1): * ZENON will work with civil works time line to meet client needs as applicable.

5.0 STANDARD TERMS AND CONDITIONS

ZENON desires to provide its Customers with prompt and efficient service. To negotiate individually the Terms and Conditions of each Sales contract would substantially impair ZENON's ability to provide such service. Accordingly, Products and Services furnished by ZENON are sold only on the Terms and Conditions stated herein. Notwithstanding any terms or conditions on Customer's order, ZENON's performance of any contract is expressly made conditional on Customer's agreement to ZENON's Terms and Conditions of Sale unless otherwise specially agreed to in writing by ZENON. In the absence of such agreement, commencement of performance and/or shipment shall be for Customer's convenience only and shall not be deemed or construed to be acceptance of Customer's Terms and Conditions, or any of them. If a contract is not earlier formed by mutual agreement in writing, acceptance of any Product or Service shall be deemed acceptance of the Terms and Conditions stated herein. All contracts for the Sale of Products shall be construed under and governed by the law of the location of ZENON's plant at Oakville, Ontario, Canada.

QUOTATION AND PRICES

All quotations are subject to the Terms and Conditions stated herein as well as any additional Terms and Conditions that may appear on the face hereof. In the case of a conflict between the Terms and Conditions stated herein and those appearing on the face hereof, the latter shall control. ZENON's prices and quotations are subject to the following:

a) All published prices are subject to change without notice.

b) **Unless otherwise specified in writing, all quotations expire thirty (30) days after date thereof, may be terminated earlier by notice and constitute only solicitations for offer to purchase;** further, budgetary quotations and estimates are for preliminary information only and shall neither constitute offers, nor impose any obligation or liability upon ZENON.

c) Unless otherwise stated in writing by ZENON, all prices quoted shall be exclusive of transportation, insurance, taxes (including, without limitation, any sales, use, or similar tax, and any tax levied on or assessed to ZENON after Product shipment by reason of ZENON's retention of a security interest as provided herein), license fees, customs fees, duties and other charges related thereto and Customer shall report and pay any and all such shipping charges, premiums, taxes, fees, duties and other charges related thereto, and shall hold ZENON harmless therefrom, provided that, if ZENON, in its sole discretion, chooses to make any such payment, Customer shall reimburse ZENON in full upon demand.

d) Stenographic, typographical and clerical errors are subject to correction.

e) Prices quoted are for Products only and do not include technical data, proprietary right of any kind, patent rights, qualification, environmental or other than ZENON's standard tests and other than ZENON's normal domestic commercial packaging unless expressly agreed to in writing by ZENON.

f) Published weights and dimensions are approximate only. Certified dimension drawings can be obtained upon request. Manuals, drawings or other documentation required hereupon must be referenced specifically.

This is merely a quotation, and the technology disclosed herein may be covered by one or more ZENON Environmental Inc. (ZENON) patents or patent applications. Any disclosure in this offer does not hereby grant, and nothing contained in the offer shall obligate ZENON to grant, an option to obtain a license to any technology or any other rights under any patent now or hereafter owned or controlled by ZENON.

TERMS OF PAYMENT

Unless credit is granted or otherwise specified in writing, payment is due upon shipment. All payments on approved credit accounts shall be due in full thirty (30) days from date of invoice. Past due balances shall be subject to a service charge of 1-1/2% per month (18% per annum), but not more than the amounts allowed by law. Partial shipments will be billed as made and payments therefor are subject to the above terms. Payment shall not be withheld for delay in delivery of required documentation unless a separate price is stated therefor, and then only to the extent of the price stated for such undelivered documentation. ZENON may cancel or delay delivery of Products in the event Customer fails to make prompt payment therefor, or in the event of an arrearage in Customer's account with ZENON. ZENON hereby retains a security interest in the Products furnished until Customer has made payment in full in accordance with the terms hereof. Customer shall cooperate fully with ZENON to execute such documents and to accomplish such filings and/or recordings thereof as ZENON may deem necessary for the protection of ZENON's interest in the Products furnished.

TRANSPORTATION AND RISK OF LOSS

Transportation will normally follow Customer's shipping instructions, but ZENON reserves the right to ship Products freight collect and to select the means of transportation and routing when Customer's instructions are deemed unsuitable. Unless otherwise advised, ZENON may insure to full value of the Products or declare full value thereof to the transportation company at the time of shipment and all freight and insurance costs shall be for Customer's account. Risk of loss and/or damage shall pass to Customer at the FCA point, which shall be the point of manufacture or such other place as ZENON shall specify in writing, notwithstanding installation by or under supervision of ZENON. Confiscation or destruction of, or damage to, Products shall not release, reduce or in any way affect the liability of Customer therefor. All Products must be inspected upon receipt and claims should be filed with the transportation company when there is evidence of shipping damage, either concealed or external. Notwithstanding any defect or nonconformity, or any other matter, risk or loss and/or damage shall remain with the Customer until the Products are returned at Customer's expense to such place as ZENON may designate in writing. Customer, at its expense, shall fully insure Products against all loss and/or damage until ZENON has been paid in full therefor, or the Products have been returned, for whatever reason, to ZENON.

PERFORMANCE

ZENON will make all reasonable effort to observe its dates indicated for performance. However, ZENON shall not be liable in any way because of any delay in performance hereupon due to unforeseen circumstances or to causes beyond its control, including, without limitation, strike, lockout, riot, war, acts of terrorism, fire, act of God, accident, failure or breakdown of components necessary to order completion, subcontractor, supplier or customer caused delays, inability to obtain or substantial rises in the price of labour, materials or manufacturing facilities, curtailment of, or failure to obtain sufficient, electrical or other energy supplies, or compliance with any law, regulation or order, whether valid or invalid of any cognizant governmental body or any instrument thereof whether now existing or hereafter created. Performance shall be deemed suspended during, and extended for, such time as any such circumstances or causes delay its execution. Whenever such circumstances or causes are remedied, ZENON will make, and Customer shall accept, performances hereupon. In addition, ZENON's inventories and current production must be allocated so as to comply with applicable Government regulations. In the absence of such regulations, ZENON reserves the right, in its sole discretion, to allocate inventories and current production and substitute suitable materials when, in its opinion, such allocation or substitution is necessary due to such circumstances or causes. No penalty clause of any kind shall be effective. As used herein, "performance" shall include, without limitations, fabrication, shipment, delivery, assembly, installation, testing, and warranty repair or replacement as applicable.

ACCEPTANCE

The furnishing by ZENON of a Product to the Customer shall constitute acceptance of that Product by Customer, unless notice of defect or nonconformity is received by ZENON within thirty (30) days of receipt of the Product at Customer's designated receiving address; provided that, for Product for which ZENON agrees in writing to perform acceptance testing after installation, the completion of ZENON's applicable acceptance tests, or execution of ZENON's acceptance form by Customer, shall constitute acceptance of the Product by Customer. Notwithstanding the foregoing, any use of a Product by Customer, its agents, employees, contractors or licensees for any purpose, after receipt thereof, shall constitute acceptance of that Product by Customer. ZENON may repair or, at its option, replace defective or non-conforming parts after receipt of notice of defect or nonconformity.

ASSIGNMENTS AND TERMINATIONS

Any assignment by Customer of any contract hereupon without the express written consent of ZENON is void. No order may be terminated by Customer except by mutual agreement in writing. Terminations by mutual agreement are subject to the following conditions:

a) Customer will pay, at applicable contract prices, for all Products which are completely manufactured and allocable to Customer at the time of ZENON's receipt of notice of termination.

b) Customer will pay all costs, direct and indirect, which have been incurred by ZENON with regard to Products which have not been completely manufactured at the time of ZENON's receipt of notice of termination.

c) Customer will pay a termination charge on all other determined costs and other charges. To reduce termination charges, ZENON will divert completed parts, material or work-in-process from terminated contracts to other Customer's whenever, in ZENON's sole discretion, it is practicable to do so.

ZENON may terminate the agreement for cause, at its discretion, whenever approved payments are overdue.

PATENTS AND OTHER INDUSTRIAL PROPERTY RIGHTS

ZENON will hold Customer harmless, as set forth herein, in respect to any claim that the design or manufacture of any Product in ZENON's commercial line of Products, or manufactured to specifications set by ZENON and furnished herein, constitutes an infringement of any patent or other industrial property rights of the United States or Canada. ZENON will pay all damages and costs, either awarded in a suit or paid, in ZENON's sole discretion, by way of settlement, which are based on such claim of infringement, provided that ZENON is notified promptly in writing of such claim of infringement but there is no liability whatsoever herein with respect to any claims settled by Customer without ZENON's prior written consent. In the event that ZENON is required to hold Customer harmless hereupon, ZENON will, in its sole discretion and at its own expense, either procure for Customer the right to continue using said Product, replace it with a non-infringing product, or remove it and refund an equitable portion of the selling price and transportation costs thereof. **This shall constitute ZENON's entire liability for any claim based upon or related to any alleged infringement of any patent or other industrial rights.** Customer shall hold ZENON harmless against any expense, loss, costs or damages resulting from claimed infringement of patents, trademarks, or other industrial property rights arising out of compliance by ZENON with Customer's designs, specifications, or instructions. **ZENON disclaims liability for U.S. or Canadian patent or copyright infringement arising from use or manufacture by anyone of inventions in connection with products or services sold, used, or intended for sale or use, in performing contracts within the United States or Canada.**

WARRANTY

1. Unless otherwise agreed to in writing, ZENON warrants its Products to be free from defects in material or workmanship for a period of 12 months from the shipment of Product by ZENON, provided that such Product are used, cleaned and maintained in accordance with the ZENON's instructions. This warranty does not apply to normally replaceable parts or components such as filter cartridges, pump seals, membranes etc., (see below for membrane warranties).

2. Customer undertakes to give immediate notice to ZENON if goods or performance appear defective and to provide ZENON with reasonable opportunity to make inspections and tests. If ZENON is not at fault, Customer shall pay ZENON the costs and expenses of the inspections and tests.

3. ZENON's obligations under this warranty are limited to the repair or replacement at its factory, of any device or part thereof which shall prove to have been thus defective. If Customer asks ZENON to replace defective parts at Customer's premises, Customer agrees to pay for any traveling time and expenses, plus the ZENON's labour to complete the replacement/repair.

4. Goods shall not be returned to ZENON without ZENON's permission. ZENON will provide Customer with a "Return Material Authorization" number to use for returned goods. All returns are F.O.B. - Oakville, Ontario, Canada. Repaired or replaced items will be

shipped back to customers from ZENON FCA Oakville, Ontario.

5. Warranty on the membranes applies only if the membrane element(s) has been operated and cleaned according to ZENON's instructions. When either permeate or concentrate flow drops by 10% from the original rates at the same operating conditions, cleaning must be initiated or the warranty will be null and void. Elements must be clean and be kept moist. They should be shipped to ZENON in water-tight bags and must be protected from freezing. **WARNING** – if element conditions of use given in ZENON's instructions are not followed, the warranty will be null and void.

Implied warranties, including but not limited to warranties of fitness for particular purpose, use or application, and all other obligations or liabilities on the part of the ZENON, unless such warranties, obligations or liabilities are expressly agreed to in writing by ZENON, are null and void.

DAMAGES AND LIABILITY

ZENON's liability for damages shall not exceed the payment, if any, received by ZENON for the unit of product or service furnished or to be furnished, as the case may be, which is the subject of claim or dispute, to a maximum of ten percent (10%) of ZENON's total contract value for all such claims under this Agreement. In no event will ZENON be liable for incidental, consequential or special damages of any kind, however caused, arising out of, or in any way connected with, the products furnished by ZENON to Customer.

DISPUTES

All disputes under any contract concerning Products not otherwise resolved between ZENON and Customer shall be resolved in a court of competent jurisdiction for the location of ZENON's plant at Oakville, Ontario, Canada, and no other place. Provided that, in ZENON's sole discretion, such action may be heard in some other place designated by ZENON, if necessary to acquire jurisdiction over third persons, so that the dispute can be resolved in one action. Customer hereby consents to the jurisdiction of such court or courts and agrees to appear in any such action upon written notice thereof. No action, regardless of form arising out of, or in any way connected with, the Products or Services furnished by ZENON, may be brought by Customer more than one (1) year after the cause of action has occurred. If any part, provision or clause of the Terms and Conditions of Sale, or the application thereof to any person or circumstances, is held invalid, void or unenforceable, such holding shall not affect and shall leave valid all other parts, provisions, clauses or applications of the Terms and Conditions remaining, and to this end the Terms and Conditions shall be treated as severable.

NON-EXCLUSIVE ROYALTY FREE LICENSE

ZENON grants Customer a non-exclusive royalty free license to make or use any process or apparatus claimed in any patent owned by ZENON but only to the extent that this license is required by Customer to build and operate the Membrane System described in this contract using ZeeWeed® membrane modules supplied by ZENON. All other rights are reserved.

The enclosed materials are considered proprietary property of ZENON Environmental. No assignments either implied or expressed, of intellectual property rights, data, know how, trade secrets or licenses of use thereof are given. All information is provided exclusively to the addressee and agents of the addressee for the purposes of evaluation and is not to be reproduced or divulged to other parties, nor used for manufacture or other means, without the express written consent of ZENON Environmental. The acceptance of this document will be construed as an acceptance of the foregoing conditions.

UTAH DEPARTMENT OF CORRECTIONS

PRISON SITE LOCATION STUDY
RUSH VALLEY SITE
WATER SUPPLY FATAL FLAW ANAYSIS
Stantec Project No. 186302095

DRAFT TECHNICAL MEMORANDUM
May 27, 2008

I. INTRODUCTION

The purpose of this technical memorandum is to outline the fatal flaw analysis for supplying water to the proposed Rush Valley State Prison location. The analysis will include a study of the site's water demands, a water rights investigation, and a hydrogeologic review. The study of the site's water demands will be based on information from the Utah Department of Corrections (UDC) and their proposed prison size. The water rights investigation will study the possibility of acquiring new appropriations, purchasing existing appropriations, or transferring currently held appropriations from one basin to another. The hydrogeologic review will determine the feasibility of placing wells near the proposed site, using existing sources, or building a pipeline to supply the site.

II. SITE WATER DEMANDS

Water demands for the proposed prison site will be determined based on a 6,000 bed prison. Usage will also be investigated for a 10,000 bed prison as requested by the UDC. Prison water usage estimates will be based on usage data from the existing Draper prison site. Usage at that site is 115 gallons per day (gpd) per bed.

Overall water usage has been estimated as follows:

- 6,000 bed site – 770 ac-ft per year/500 gpm
- 10,000 bed site – 1,290 ac-ft per year/800 gpm

III. WATER RIGHTS

The Rush Valley Area is part of Groundwater Management Area 15. In Rush Valley, surface waters are considered to be fully appropriated. New groundwater appropriations are restricted to small appropriations up to 4.73 acre-feet. This level of new appropriation will not be adequate for the prison site.

The remaining possibilities are:

- Transfer currently held appropriations from the Salt Lake Valley to the Rush Valley – may be possible, but is very limited.
- Purchase water rights in Rush Valley – depends on availability.
- Import water in from Skull Valley – Skull Valley is open to new appropriations.
- Import water from another locations TBD.

IV. HYDROGEOLOGIC REVIEW

The hydrogeologic review will be the next step in the fatal flaw analysis once a apecific area within Rush Valley has been determined. The review will include an analysis of bedrock geology, existing well logs, aerial photography, and irrigation uses.

Utah Division of Water Rights

TOOELE & RUSH VALLEYS - AREA 15

Updated: April 24, 2008
Changes from previous version in red text

DESCRIPTION: Located on the eastern edge of the Tooele County from T4N to T10S, these two valleys are administered separately because of the weak hydrologic connection they have through South Mountain. This area is bounded on the north by the Great Salt Lake, on the west by the Stansbury and Onaqui Mountains, on the east by the Oquirrh and East Tintic Mountains, and on the south by the Sheeprock Mountains. The highest point in the area is 11,031 foot Deseret Peak, while the lowest is the shore of the Great Salt Lake at about 4,200 feet, giving a total relief of about 6,830 feet. Click here to see a map of the area.

MANAGEMENT: Three Proposed Determination of Water Rights books and an addendum have been published for this area between 1973 and 1999, however, no pre-trial orders or final decrees have been issued. There are no state-administered distribution systems in this area. The Tooele Valley portion of this area is subject to the conditions of the 1996 Tooele Valley Ground-water Management Plan. A public meeting was held on July 7, 2004 to discuss the Northeast Boundary Plume and an Amendment to the Tooele Valley Groundwater Management Plan was issued on September 22, 2004, the linked PDF file includes a map of the area discussed. Click here to see statistics for this area.

SOURCES:
SURFACE WATER - Surface waters are considered to be fully appropriated. New diversions and consumptive uses in these sources must be accomplished by change applications filed on owned or acquired rights. Non-consumptive use applications, such as hydroelectric power generation, will be considered on their individual merits. The only exception is for small amounts from sources that would otherwise flow to the Great Salt Lake.

GROUND WATER - Tooele Valley is closed to appropriations except for small amounts of shallow ground water (less than 10 feet from the surface) which would otherwise flow to the Great Salt Lake. New diversions and consumptive uses in other sources must be accomplished by change applications filed on owned or acquired rights. Rush Valley is open to small appropriations up to 4.73 acre-feet. Changes from surface to underground sources, and vice versa, are also considered on their individual merits, with emphasis on the existence of a hydrologic tie between the two sources, the potential for interference with existing rights, and to ensure that there is no enlargement of the underlying rights. Non-consumptive use applications, such as hydroelectric power generation, will be considered on their individual merits. Temporary appropriations may be allowed for very short term projects. Applicants are placed on notice that development should be pursued as soon as possible. Extension of time requests will be critically reviewed beyond the initial five-year period.

GENERAL: Applications are advertised in the *Tooele Transcript*. The general irrigation diversion duty for this area, which the State Engineer uses for evaluation purposes, is generally 4.0 acre-feet per acre per year. The consumptive use requirement is determined from the publication Consumptive Use of Irrigated Crops in Utah, Research Report 145, Utah State University, 1994, unless the applicant submits other data for consideration. This area is administered by the Weber River Regional Office in Salt Lake City.

REFERENCES:

Technical Publication No. 4, Ground Water in Tooele Valley, Tooele County, Utah; Utah State Engineer; 1946.

Technical Publication No. 12, Reevaluation of the Ground-Water Resources of Tooele Valley, Utah; Utah State Engineer; 1965.

Technical Publication No. 23, Hydrologic Reconnaissance of Rush Valley, Tooele County, Utah; Utah Department of Natural Resources; 1969.

Technical Publication No. 69, Ground-Water Conditions in Tooele Valley, Utah, 1976-78; Utah Department of Natural Resources; 1981.

Technical Publication No. 107, Hydrology and Potential for Ground-Water Development in Southeastern Tooele Valley and Adjacent Areas in the Oquirrh Mountains, Tooele County, Utah; Utah Department of Natural Resources; 1994.

Water Circular No. 2, Ground Water in Tooele Valley, Utah; Utah Department of Natural Resources; 1970.

Basic Data Report No. 7, Selected Hydrologic Data, Tooele Valley, Tooele County, Utah; Utah State Engineer; 1963.

Information Bulletin No. 26, Test Drilling for Fresh Water in Tooele Valley, Utah; Utah State Engineer; 1981.

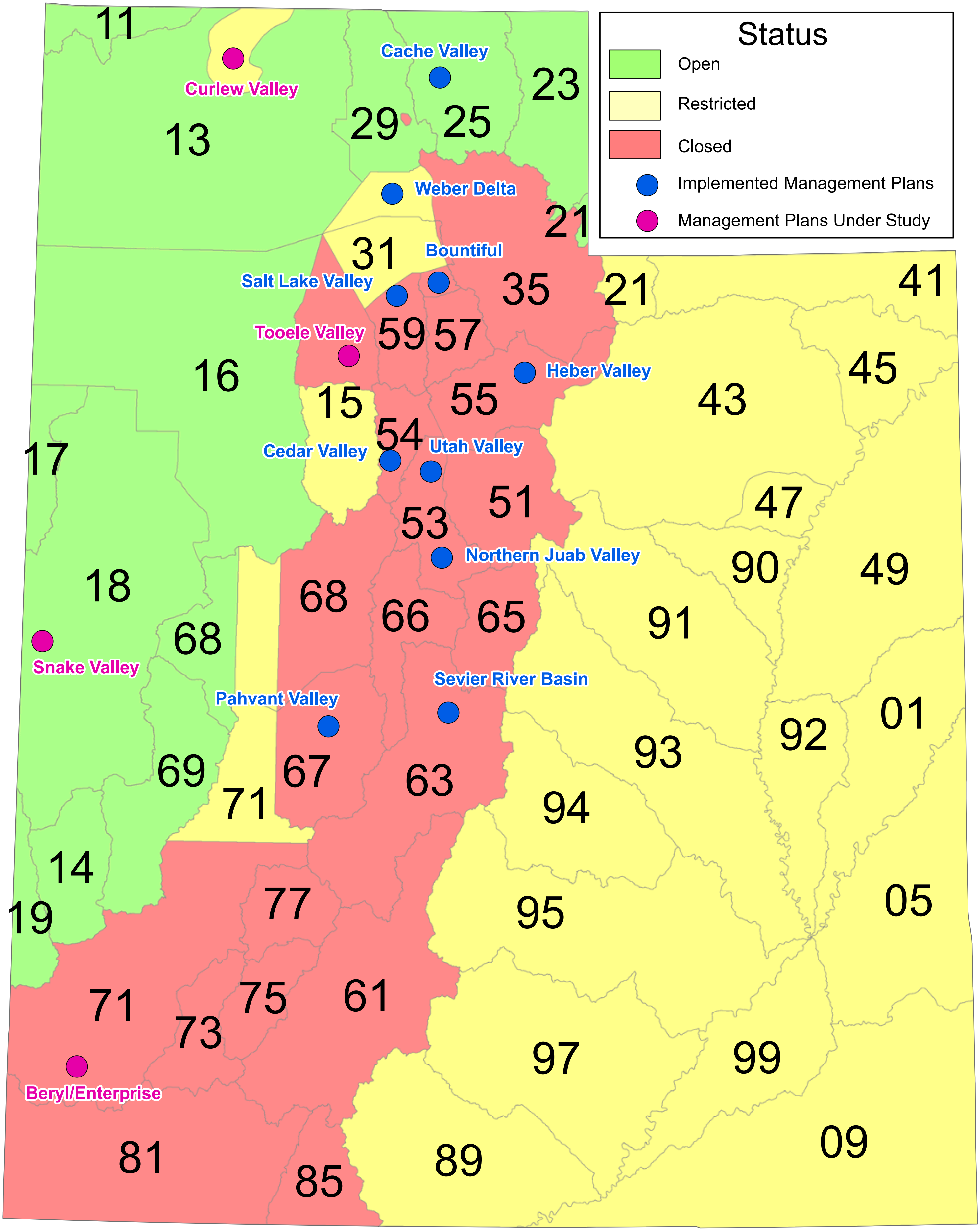
Water-Resources Investigative Report 95-4173, Simulated Effects of Proposed Ground-Water Pumping in 17 Basins in East-Central and Southern Nevada;
U.S. Geological Survey; 1995 (viewing this document requires the DjVu browser plugin available from LizardTech)

MODELING: Regional Ground-Water Flow, Carbonate-Rock Province, Nevada, Utah, and Adjacent States; USGS Open-File Reports 93-170 and 93-420; 1993.

Tooele Valley Ground-Water Flow Model, 1994.

PAGE UPDATES: July 27, 2004, September 24, 2004

Ground-Water Policy



Memo

To: Greg Peay
Utah Department of Corrections

From: Deidre Beck, PG
Stantec Consulting Inc.

File: Stantec Project #186302095

Date: August 12, 2008

Reference: Hydrogeologic Review of Parcels 2 and 3

1.0 Introduction

This memo summarizes the findings of a hydrogeologic review performed by Stantec Consulting Inc. for the Utah Department of Corrections (UDC) in the Rush Valley region of Tooele County, Utah. Rush Valley is an elongated depression located in Tooele County south of Stockton and north of the Sheeprock Mountains as illustrated in Figure 1. For the purpose of this investigation, the study area was limited to those areas adjacent to the previously selected Parcels 2 and 3. Parcels 2 and 3 are located several miles south of Stockton and directly east of the town of Rush Valley. The purpose of this review has been to evaluate the productive capabilities of groundwater sources in the vicinity of Parcels 2 and 3 with respect to meeting the future water demand of 500 – 800 gallons per minute (gpm) for the proposed prison site.

1.1 Sources of Data

The information presented in this evaluation has been assembled from numerous sources including:

- Existing published geologic and hydrogeologic information for the region;
- Technical Publications authored by the Utah Department of Natural Resources Division of Water Rights and the U.S. Geological Survey;
- Well logs from existing wells; and,
- Aerial photographs from the National Agricultural Imagery Program (NAIP) from 2006.

2.0 Physiographic and Hydrogeologic Setting

Rush Valley covers approximately 250,000 acres and is a closed basin typical of the Basin and Range Physiographic Province [Hood, et.al., 1969]. The mountains that bound Rush Valley are folded and faulted sedimentary, metamorphic and igneous rocks. These include the Oquirrh and East Tintic Mountains on the East, the Stansbury

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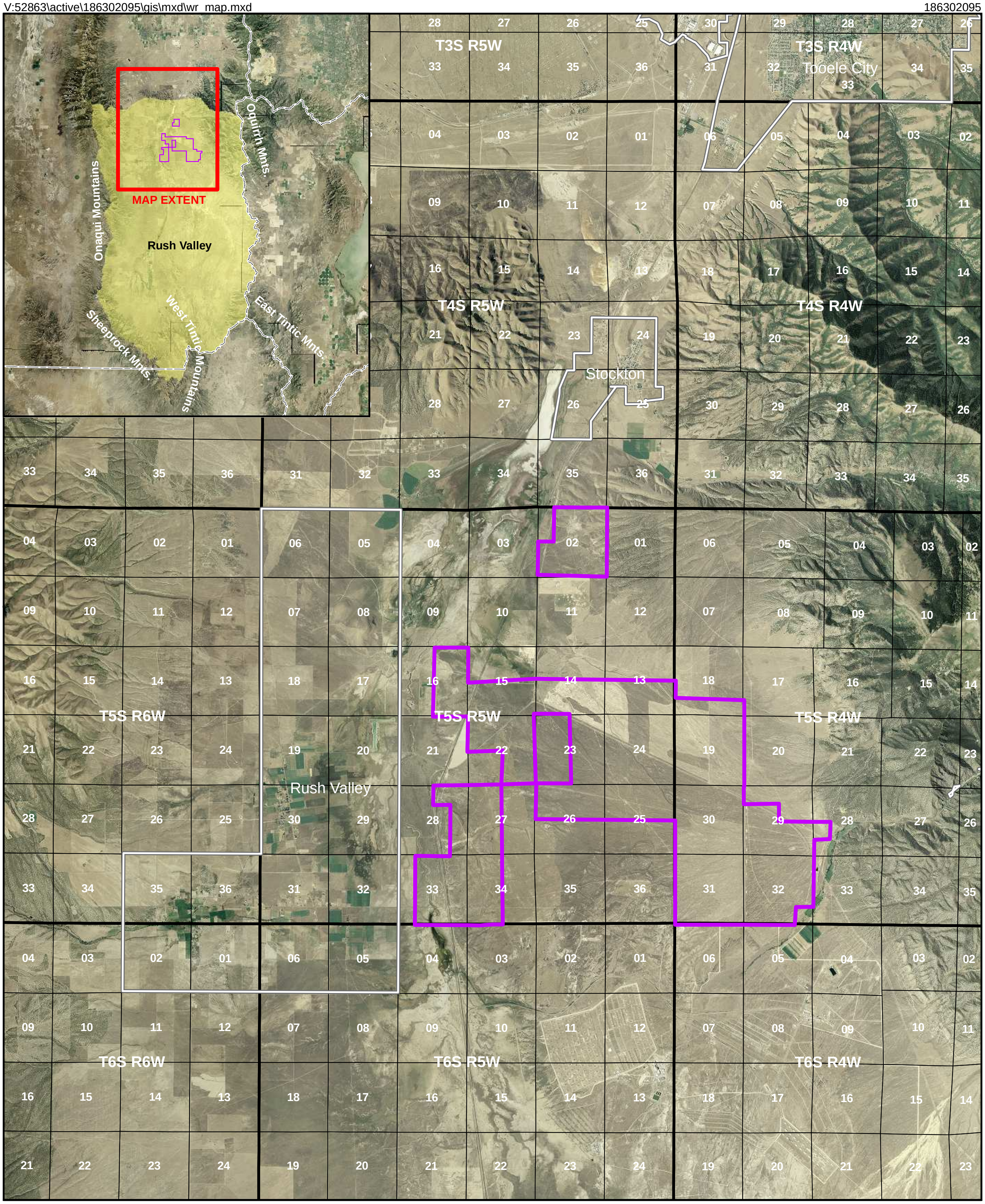

Stantec Consulting Inc.
3995 S 700 E, Ste. 300
Salt Lake City, Utah
84107-2540
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Fax 801.266.1671
www.stantec.com

Legend

- ▭ Parcels 2 and 3
- ▭ Municipal Boundaries
- ▭ Sections
- ▭ County Boundaries
- 🟨 Rush Valley

N

Graphic Scale
0 2
Miles
1 inch equals 2 miles

Client/Project
UTAH DEPARTMENT OF CORRECTIONS
HYDROGEOLOGIC REVIEW
PRISON SITE LOCATION STUDY

Figure No.
1

Title
SITE LOCATION MAP

and Onaqui chains on the west and the Sheeprock and West Tintic Mountains to the south.

Consolidated rocks form the mountains surrounding Rush Valley. The consolidated rocks can be divided as follows:

1) metasedimentary rocks of Precambrian Age and the Tintic Quartzite of Cambrian Age. The Precambrian rocks and Tintic Quartzite crop out only in the Sheeprock Mountains and the quantity of water stored is small.

2) Paleozoic sedimentary rocks which are mainly carbonates. The Paleozoic sedimentary rocks are exposed in the mountains and underlie younger rocks in parts of Rush Valley. Some formations of Paleozoic age yield large quantities of water including the Manning Canyon Shale and the Oquirrh Formation. The Oquirrh Formation yields large quantities to two wells owned by Tooele City drilled north of Vernon, with rates estimated at 4,100 gpm and 8,600 gpm, respectively. These two wells were drilled on the trace of a covered fault and another well drilled west of the fault trace yielded much less. Therefore large well yields appear to depend on localized favorable conditions. These wells are approximately 14 miles south of Parcels 2 and 3.

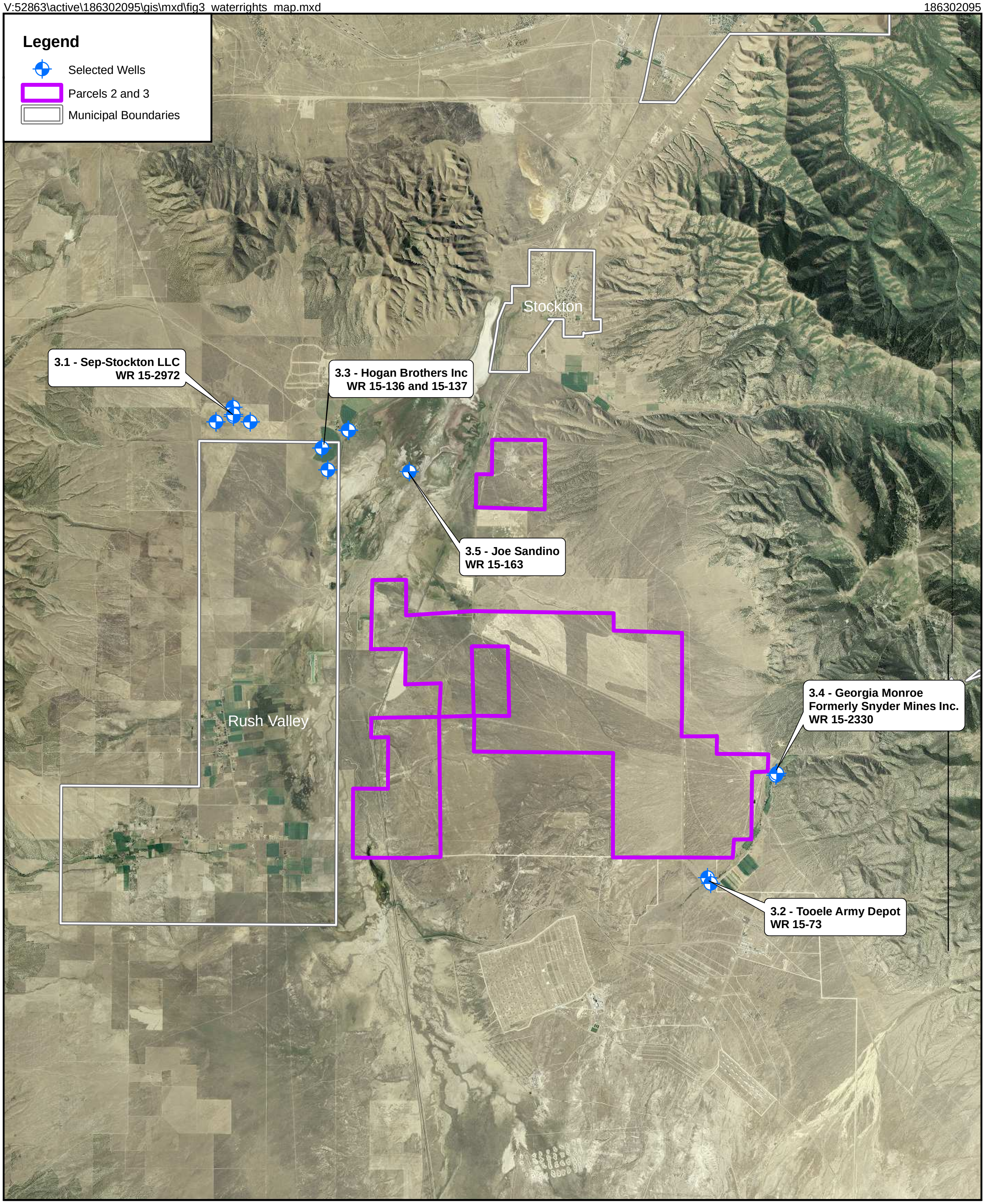
3) Tertiary igneous rocks, and the Salt Lake Formation of Pliocene age. Both the Tertiary igneous rocks and the Salt Lake Formation have low permeability and do not have much water yielding potential.

Although groundwater may be locally available from bedrock formations, the main groundwater reservoir in Rush Valley is in the unconsolidated rocks of late Tertiary and Quaternary age. The source of all water in Rush Valley is precipitation that falls on the mountains. The normal annual precipitation in Rush valley is less than 10 inches in the lowlands to more than 40 inches in the Oquirrh and Stansbury Mountains. In the vicinity of the Parcels 2 and 3, the unconsolidated rocks consist of 20-100 feet of coarse-grained deposits that rest on a thick section of pre-Lake Bonneville lacustrine clay. The majority of wells surrounding Parcels 2 and 3 yield less than 50 gpm except those that will be discussed in more detail in the following section.

3.0 Existing Wells

Based on a Utah Division of Water Rights (UDWR) database search around Parcels 2 and 3, the majority of wells nearby yield less than 100 gpm. Several wells were found that yield quantities of water in excess of 100 gpm. These wells are illustrated on Figure 2 and details about each follow.

V:52863\active\186302095\gis\mxd\fig3_waterrights_map.mxd 186302095



Stantec Consulting Inc.
3995 S 700 E, Ste. 300
Salt Lake City, Utah
84107-2540
Tel. 801.261.0090
Fax 801.266.1671
www.stantec.com

N

Graphic Scale
0 2
Miles
1 inch equals 2 miles

Client/Project
UTAH DEPARTMENT OF CORRECTIONS
HYDROGEOLOGIC REVIEW
PRISON SITE LOCATION STUDY

Figure No.
2

Title
SELECTED UNDERGROUND POINTS OF DIVERSION

3.1 Sep-Stockton LLC Wells (WR 15-2972)

The Sep-Stockton Wells include several existing and abandoned wells. The first well drilled in 1987 flowed artesian and was capable of 1,350 gpm with 60 feet of drawdown. This well was drilled to a depth of 340 feet. This well was later abandoned. A second well was drilled in 1990 to a depth of 315 feet and was capable of 1,000 gpm with 90 feet of drawdown. This well was later abandoned as well. A third well was drilled in 2000 to a depth of 425 feet and flowed artesian at a rate of approximately 12 gpm. This well was never developed or tested, and was later abandoned. A fourth well was drilled in 2005 to a depth of 900 feet. According to the Well Driller's Report (attached), this well encountered quartzite bedrock at an approximate depth of 517 feet. This well was later pumped at a rate of 2,250 gpm with 271 feet of drawdown.

3.2 USA Department of the Army – Tooele Army Depot (WR 15-73)

The United States Army has two wells at the Deseret Chemical Warfare Depot. Both wells were drilled in 1942 to depths of 404 feet and 428 feet, respectively. Both were completed in gravels and are capable of approximately 370 gpm with 5 to 10 feet of drawdown (see attached Well Driller's Reports).

3.3 Hogan Brothers Inc (WR 15-136 and 15-137)

The Hogan Brothers Wells include three well sources. Two have no information on production potential while a third that was drilled in 1973 to a depth of 209 feet is capable of 1,140 gpm with 77 feet of drawdown. According to the Well Drillers Report (attached) this well was completed in unconsolidated sands and gravels.

3.4 Georgia Monroe – formerly Snyder Mines Inc (WR 15-2330)

Two wells formerly owned by Snyder Mines Inc were drilled in 1937 to depths of 86 feet and 90 feet, respectively (see attached Well Driller's Reports). The first is capable of 146 gpm with 15.5 feet of drawdown. The second is capable of 178 gpm with 15.5 feet of drawdown.

3.5 Joe Sandino (WR 15-163)

This well was completed to a depth of 300 feet in 1963 and flowed artesian. Based on the Well Driller's Report (attached), the well was estimated to flow 650 gpm in 1963 when it was drilled. The well appears to be completed in unconsolidated sands and gravels.

4.0 Summary and Recommendations

Based on a review of the Utah Division of Water Rights database there are several wells in the vicinity of Parcels 2 and 3 that are capable of discharge rates greater than 100 gpm and as great as 2,250 gpm. The well that yielded 2,250 gpm was drilled to 900 feet bls and encountered bedrock conditions. All other wells investigated target unconsolidated sands and gravels.

Based on the information provided in this hydrogeologic review, it may be possible to drill several wells in the unconsolidated sands and gravels on Parcels 2 and 3 that would supply the required demand of 500 – 800 gpm. It is unclear if the required demand could be supplied by only one well. It is likely that more than one well would need to be drilled to supply the required demand. It also may be possible to target a bedrock aquifer(s), but a more detailed well siting study would be required. Regardless of the target formation, if wells are drilled in the area a test well program is recommended. A test well program would provide the additional data needed to fully evaluate the groundwater resource.

If you have any questions or comments concerning this memo, please contact me or Mike Kobe at 801-261-0090.

Sincerely,

Stantec Consulting Inc

Deidre Beck

Deidre Beck, PG
Hydrogeologist
dbeck@stantec.com

Attachment: Well Driller's Reports

c. Moya Kessig, Wikstrom

Geoffrey Butler, Wikstrom

Mike Kobe, PE, Stantec Consulting Inc

Ken Engstrom, PE, Stantec Consulting Inc

15-2972

AM—12-60

d

d: B. C. T. B.

tion Sheet

d

REPORT OF WELL DRILLER
STATE OF UTAH

Application No. A-13358

Claim No.

Coordinate No.

ENERAL STATEMENT: Report of well driller is hereby made and filed with the State Engineer, in accordance with the laws of Utah. This report shall be filed with the State Engineer within 30 days after the completion or abandonment of the well. Failure to file such reports constitutes a misdemeanor.)

(1) WELL OWNER:
Name Ellsworth Johnson
Address 14747 So 1690 West Bluffdale

(2) LOCATION OF WELL:
County Tooele Ground Water Basin (leave blank)

~~North~~ South 1249 feet, East ~~West~~ 1249 feet from South Corner

of Section 31, T 4 ~~N~~ S, R 5W E SLBM W USM (strike out words not needed)

(3) NATURE OF WORK (check):
New Well ☒

Replacement Well ☐ Deepening ☐ Repair ☐ Abandon ☐

If abandonment, describe material and procedure:

(4) NATURE OF USE (check):
Domestic ☐ Industrial ☐ Municipal ☐ Stockwater ☐

Irrigation ☒ Mining ☐ Other ☐ Test Well ☐

(5) TYPE OF CONSTRUCTION (check):
Rotary ☐ Dug ☐ Jetted ☐

Cable ☒ Driven ☐ Bored ☐

(6) CASING SCHEDULE:
Threaded ☐ Welded ☒

12" Diam. from 0 feet to 340 feet Gage C250

" Diam. from feet to feet Gage

" Diam. from feet to feet Gage

New ☐ Reject ☐ Used ☐

(7) PERFORATIONS:
Perforated? Yes ☒ No ☐

Type of perforator used Cutting torch

Size of perforations 1/4 inches by inches

1/4 perforations from 100 feet to 340 feet

perforations from feet to feet

perforations from feet to feet

perforations from feet to feet

perforations from feet to feet

(8) SCREENS:
Well screen installed? Yes ☐ No ☒

Manufacturer's Name

Type Model No.

Diam. Slot size Set from ft. to

Diam. Slot size Set from ft. to

(9) CONSTRUCTION:
Was well gravel packed? Yes ☐ No ☒ Size of gravel:

Gravel placed from feet to feet

Was a surface seal provided? Yes ☒ No ☐

To what depth? 60 feet

Material used in seal: Cement & Bentonite

Did any strata contain unusable water? Yes ☐ No ☒

Type of water: Depth of strata

Method of sealing strata off: Pressure Grout & Bentonite

Was surface casing used? Yes ☐ No ☐

Was it cemented in place? Yes ☑ No ☐

(10) WATER LEVELS:
Static level feet below land surface Date

Artesian pressure 0 feet above land surface Date April 1 87

LOG RECEIVED: 12/30/87

(11) FLOWING WELL:
Controlled by (check) Valve ☒

Cap ☐ Plug ☐ No Control ☐

Does well leak around casing? Yes ☐ No ☒

(12) WELL TESTS:
Drawdown is the distance in feet the water level is lowered below static level.

Was a pump test made? Yes ☐ No ☐ If so, by whom?

Yield: 1350 gal./min. with 60 feet drawdown after 24 hours

" " " "

" " " "

Bailer test gal./min. with feet drawdown after hours

Artesian flow 400 g.p.m. Date April 87

Temperature of water 70 Was a chemical analysis made? No ☒ Yes ☐

(13) WELL LOG:
Diameter of well 12 inches

Depth drilled 340 feet. Depth of completed well 340 feet.

NOTE: Place an "X" in the space or combination of spaces needed to designate the material or combination of materials encountered in each depth interval. Under REMARKS make any desirable notes as to occurrence of water and the color, size, nature, etc., of material encountered in each depth interval. Use additional sheet if needed.

DEPTH		MATERIAL										REMARKS
From	To	Clay	Silt	Sand	Gravel	Cobbles	Boulders	Hardpan	Conglomerate	Bedrock	Other	
0	4											Top Soil
4	30	X										SurFace-WaTer
30	54				X							
54	80	X										
80	95				X							
95	115	X										
115	120				X							
120	145	X										
145	147						X					
147	160							X				
160	163										X	Sand Stone
163	180										X	Sollide Rock
180	250	X										
250	260							X				
260	280				X							
280	330	X										
330	340								X			

Work started June 1, 1986 Completed April 1, 1987

(14) PUMP:
Manufacturer's Name perlis pump

Type: 12 Bowles H. P. 200

Depth to pump or bowles 100 feet

Well Driller's Statement:

This well was drilled under my supervision, and this report is true to the best of my knowledge and belief.

Name Ellsworth Johnson Drilling (Person, firm, or corporation) (Type or print)

Address 14747 South 1690 West Bluffdale 84065

(Signed) Ellsworth Johnson (Well Driller)

License No. 577 Date Nov 30, 1987

USE OTHER SIDE FOR ADDITIONAL REMARKS

Form 113—5M—12-60

183

Examined
Recorded: B. C. T. B.
Inspection Sheet
Copied

REPORT OF WELL DRILLER
STATE OF UTAH

Application No. A-13358
Claim No. 15-2972
Coordinate No.

GENERAL STATEMENT: Report of well driller is hereby made and filed with the State Engineer, in accordance with the laws of Utah. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of the well. Failure to file such reports constitutes a misdemeanor.)

(1) WELL OWNER:
Name Ellsworth Johnson
Address 14747 So. 1690 West Bluffdale

(2) LOCATION OF WELL: No 2 Well
County Tooele Ground Water Basin (leave blank)
~~North~~ South 1249 feet, East ~~West~~ 1249 feet from South Corner of Section 31, T. 4 ~~N~~ S, R. 5W ~~E~~ SLBM W USM (strike out words not needed)

(3) NATURE OF WORK (check):
New Well ☒
Replacement Well ☐ Deepening ☐ Repair ☐ Abandon ☐
If abandonment, describe material and procedure:

(4) NATURE OF USE (check):
Domestic ☐ Industrial ☐ Municipal ☐ Stockwater ☐
Irrigation ☒ Mining ☐ Other ☐ Test Well ☐

(5) TYPE OF CONSTRUCTION (check):
Rotary ☐ Dug ☐ Jetted ☐
Cable ☒ Driven ☐ Bored ☐

(6) CASING SCHEDULE: Threaded ☐ Welded ☒
10" Diam. from 0 feet to 375 feet Gage ¼
16" Diam. from feet to feet Gage
10" Diam. from feet to feet Gage
New ☒ Reject ☐ Used ☐

(7) PERFORATIONS: Perforated? Yes ☐ No ☐
Type of perforator used Cutting torch
Size of perforations ¼ inches by 12 inches
100 perforations from 380 feet to feet
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet

(8) SCREENS: Well screen installed? Yes ☐ No ☒
Manufacturer's Name
Type Model No.
Diam. Slot size Set from ft. to
Diam. Slot size Set from ft. to

(9) CONSTRUCTION:
Was well gravel packed? Yes ☒ No ☐ Size of gravel ¾ Wash
Gravel placed from 50 feet to 200 feet
Was a surface seal provided? Yes ☒ No ☐
To what depth? 50 feet
Material used in seal: Bentonite & Hard pan clay
Did any strata contain unusable water? Yes ☐ No ☒
Type of water: Good Depth of strata
Method of sealing strata off: Tamping With drill Bit

Was surface casing used? Yes ☐ No ☒
Was it cemented in place? Yes ☐ No ☐

(10) WATER LEVELS:
Static level 30 feet below land surface Date July 7 89
Artesian pressure feet above land surface Date

LOG RECEIVED:

(11) FLOWING WELL:
Controlled by (check) Valve ☐
Cap ☐ Plug ☐ No Control ☐
Does well leak around casing? Yes ☐
No ☐

(12) WELL TESTS:
Drawdown is the distance in feet the water level is lowered below static level.
Was a pump test made? Yes ☒ No ☐ If so, by whom? Ellsworth Johnson
Yield: 1000 gal./min. with 85 feet drawdown after 24 hours
" " " "
" " " "
Driller test 600 gal./min. with 50 feet drawdown after 3 hours
Artesian flow g.p.m. Date
Temperature of water 70 Was a chemical analysis made? No ☒ Yes ☐

(13) WELL LOG:
Diameter of well inches
Depth drilled feet. Depth of completed well feet.

NOTE: Place an "X" in the space or combination of spaces needed to designate the material or combination of materials encountered in each depth interval. Under REMARKS make any desirable notes as to occurrence of water and the color, size, nature, etc., of material encountered in each depth interval. Use additional sheet if needed.

DEPTH		MATERIAL										REMARKS
From	To	Clay	Silt	Sand	Gravel	Cobbles	Boulders	Hardpan	Conglomerate	Bedrock	Other	
0	70				X		X					
70	100							X				
100	150											Sand Stone Clay
150	170				X							
170	230											Sand Stone Clay
230	275											" " "
275	300				X							
300	360											Sand Stone
360	375				X							

Work started , 19 Completed , 19

(14) PUMP:
Manufacturer's Name
Type: H. P.
Depth to pump or bowles feet

Well Driller's Statement:

This well was drilled under my supervision, and this report is true to the best of my knowledge and belief.

Name Ellsworth Johnson Drilling
(Person, firm, or corporation) (Type or print)
Address 14747 So. 1690 W. Bluffdale Utah
(Signed)
(Well Driller)
License No. 577 Date June 14 1990, 1990

USE OTHER SIDE FOR ADDITIONAL REMARKS

WELL DRILLER'S REPORT

State of Utah
Division of Water Rights
For additional space, use "Additional Well Data Form" and attach

Well Identification CHANGE APPLICATION: a24431(15-2972)

Owner *Note any changes*

Smith, S. Taylor
1070 Westfield Road
Alpine, UT 84004

Contact Person/Engineer:

Well Location *Note any changes*

COUNTY: Tooele
NORTH 1950 feet EAST 2600 feet from the SW Corner of
SECTION 31, TOWNSHIP 4S, RANGE 5W, SLB&M.

Location Description: (address, proximity to buildings, landmarks, ground elevation, local well #) West of Hogans

Drillers Activity Start Date: 6-27-00 Completion Date: 10-2-00

Check all that apply: ☒ New ☐ Repair ☐ Deepen ☐ Clean ☐ Replace ☐ Public Nature of Use:

If a replacement well, provide the location of the new well. _____ feet north/south and _____ feet east/west of the existing well.

DEPTH (feet) FROM	TO	BOREHOLE DIAMETER (in)	DRILLING METHOD	DRILLING FLUID
0	425	8 3/4	Rotary	Mud

Well Log

DEPTH (feet) FROM	TO	WATER	PERMEABLE high	PERMEABLE low	UNCONSOLIDATED CLAY	SILT	SAND	GRAVEL	COBBLES	BOULDER	OTHER	CONSOLIDATED ROCK TYPE	COLOR	DESCRIPTIONS AND REMARKS (e.g., relative %, grain size, sorting, angularity, bedding, grain composition, density, plasticity, shape, cementation, consistancy, water bearing, odor, fracturing, minerology, texture, degree of weathering, hardness, water quality, etc.)
0	20			X	X								Tan	
20	33			X	X			X					Tan	
33	50			X	X			X	X				"	
50	55							X				hardpan		
55	83			X	X			X					TAN	
83	93							X	X			hardpan		
93	101	X	X		X			X					TAN	
101	113			X	X								Tan	
113	121	X						X						
121	158	X		X	X			X					Tan	

RECEIVED
OCT 19 2000
WATER RIGHTS
SALT LAKE

Static Water Level

Date 7-18-00 Water Level _____ feet Flowing? ☒ Yes ☐ No

Method of Water Level Measurement _____ If Flowing, Capped Pressure 7 PSI

Point to Which Water Level Measurement was Referenced _____ Ground Elevation (If known) _____

Height of Water Level reference point above ground surface _____ feet Temperature 54 ☐ °C ☒ °F

Construction Information

DEPTH (feet)		CASING			DEPTH (feet)		☐ SCREEN ☐ PERFORATIONS ☒ OPEN BOTTOM		
FROM	TO	CASING TYPE AND MATERIAL/GRADE	WALL THICK (in)	NOMINAL DIAM. (in)	FROM	TO	SCREEN SLOT SIZE OR PERF SIZE (in)	SCREEN DIAM. OR PERF LENGTH (in)	SCREEN TYPE OR NUMBER PERF (per round/interval)
0	55	Steel	.281	10					

Well Head Configuration: Flange - Blind　Access Port Provided? ☒ Yes ☐ No

Casing Joint Type: Weld　Perforator Used:

Was a Surface Seal installed? ☐ Yes ☒ No　Depth of Surface Seal: ____ feet　Drive Shoe? ☐ Yes ☐ No

Surface Seal Material Placement Method:

Provide Seal Material description below:

DEPTH (feet)		SURFACE SEAL / INTERVAL SEAL / FILTER PACK / PACKER INFORMATION		
FROM	TO	SEAL MATERIAL, FILTER PACK and PACKER TYPE and DESCRIPTION	Quantity of Material Used (if applicable)	GROUT DENSITY (lbs./gal.,# bag mix, gal./sack etc.)
		10" pipe pushed into 8 3/4" Borehole to 55' at Owners instruction. Owner did not want surface seal installed.		

Well Development and Well Yield Test Information

Date	Method	Yield	Units Check One		DRAWDOWN (ft)	TIME PUMPED (hrs & min)
			GPM	CFS		
	None					
	Water flows at Rate of 12 GPM					

Pump (Permanent)

Pump Description: ——　Horsepower: ____　Pump Intake Depth: ____ feet

Approximate maximum pumping rate: ____　Well disinfected upon completion? ☐ Yes ☒ No

Comments Description of construction activity, additional materials used, problems encountered, extraordinary circumstances, abandonment procedures. *Use additional well data form for more space.*

There is some water leakage around casing. Contractor made owner aware of Surface seal requirement and hole casing or abandonment requirement. Owner called state and discussed Requirements and is willing to accept liability for method of finishing well.

Well Driller Statement This well was drilled and constructed under my supervision, according to applicable rules and regulations, and this report is complete and correct to the best of my knowledge and belief.

Name Hall Drilling Co.　**License No.** 671

(Person, Firm, or Corporation - Print or Type)

Signature Jordan Hall　**Date** 10-17-00

(Licensed Well Driller)

Water Right # a24431(15-2977) **ADDITIONAL WELL DATA FORM**

OWNER NAME S. Taylor Smith

Well Log

Page____of____

DEPTH (feet) FROM	TO	WATER	PERMEABLE high	PERMEABLE low	UNCONSOLIDATED CLAY	SILT	SAND	GRAVEL	COBBLES	BOULDER	OTHER	CONSOLIDATED ROCK TYPE	COLOR	DESCRIPTIONS AND REMARKS (e.g. relative %, grain size, sorting, angularity, bedding, grain composistion, density, plasticity, shape, cementation, consistancy, water bearing, odor, fracturing, minerology, texture, degree of weathering, hardness, water quality, etc.)
154	180			X	X								Tan	
180	185	X	X		X			X					Tan	
185	204			X	X								Tan	
204	255	X	X		X			X					Tan	
255	289	X	X		X			X	X				Tan	
289	425	X	X		X			X					Tan	

RECEIVED
OCT 19 2000
WATER RIGHTS
SALT LAKE

Construction Information (con't)

DEPTH (feet)		CASING			DEPTH (feet)		☐ SCREEN ☐ PERFORATIONS ☐ OPEN BOTTOM		
FROM	TO	CASING TYPE AND MATERIAL/GRADE	WALL THICK (in)	NOMINAL DIAM. (in)	FROM	TO	SCREEN SLOT SIZE OR PERF SIZE (in)	SCREEN DIAM. OR PERF LENGTH (in)	SCREEN TYPE OR NUMBER PERF (per round interval)

DEPTH (feet)		FILTER PACK / GROUT / PACKER / ABANDONMENT MATERIAL		
FROM	TO	ANNULAR MATERIAL, ABANDONMENT MATERIAL and/or PACKER DESCRIPTION	Quantity of Material Used (if applicable)	GROUT DENSITY (lbs./gal., # bag mix, gal./sack etc.)

Comments (con't)

Well Driller Statement

This well was drilled and constructed under my supervision, according to applicable rules and regulations, and this report is complete and correct to the best of my knowledge and belief.

Name Hall Drilling Co.
(Person, Firm, or Corporation - Print or Type)

License No. 671

Signature Jordan Hall
(Licensed Well Driller)

Date 10-17-00

WELL DRILLER'S REPORT
State of Utah
Division of Water Rights

For additional space, use "Additional Well Data Form" and attach

RECEIVED
NOV 14 2005
WATER RIGHTS
CEDAR CITY

WIN: 34702

Well Identification

Change Application: a24431 (15-2972)

RECEIVED
NOV 17 2005
WATER RIGHTS GMB
SALT LAKE

Owner *Note any changes*

S. Taylor Smith
1070 Westfield Road
Alpine UT 84004

Contact Person/Engineer: ________

Well Location *Note any changes*

N 2100 E 2600 from the SW corner of section 31, Township 4S, Range 5W, SL B&M

Location Description: (address, proximity to buildings, landmarks, ground elevation,local well #)

Drillers Activity Start Date: Sept. 8, 2005 Completion Date: Sept 27, 2005

Check all that apply: ☐ New ☐ Repair ☐ Deepen ☐ Clean ☒ Replace ☐ Public Nature of Use: Irrigation

If a replacement well, provide location of new well. 140 feet north/[✓ south] and 0 feet east/west of the existing well.

DEPTH (feet) FROM	TO	BOREHOLE DIAMETER (in)	DRILLING METHOD	DRILLING FLUID
0	560	24	Mud Rotary	Water, Bentonite
560	900	15	Air Rotary	Water, Foam

Well Log

DEPTH (feet) FROM	TO	WATER	PERMEABLE High	PERMEABLE Low	UNCONSOLIDATED CLAY	SILT	SAND	GRAVEL	COBBLES	BOULDER	OTHER	CONSOLIDATED ROCK TYPE	COLOR	DESCRIPTION AND REMARKS (e.g., relative %, grain size, sorting, angularity, bedding, grain composition density, plasticity, shape, cementation, consistancy, water bearing, ordor, fracturing, minerology, texture,degree of weathering, hardness, water quality, etc.)
0	2			X	X	X								
2	37		X		X	X	X		X					
37	125			X	X	X	X							Hit about 40 GPM @ 640'
125	230			X	X									300 GPM @ 680'
230	265			X	X	X	X							600 GPM @ 760'
265	410			X	X									1000+ GPM @ 800'
410	423			X		X	X	X						
423	517			X	X									
517	900	X	X											Quartzite (Bedrock)

Static Water Level

Date Sept. 28 Water Level 191.2 feet Flowing? ☐ Yes ☒ No

Method of Water Level Measurement Sounder If Flowing, Capped Pressure ________ PSI

Point to Which Water Level Measurement was Referenced Top of Casing Elevation ________

Height of Water Level reference point above ground surface 2 feet Temperature ________ degrees ☐ C ☐ F

Construction Information

DEPTH (feet)		CASING			DEPTH (feet)		☐SCREEN ☐PERFORATIONS ☒OPEN BOTTOM		
FROM	TO	CASING TYPE AND MATERIAL/GRADE	WALL THICK (in)	NOMINAL DIAM. (in)	FROM	TO	SCREEN SLOT SIZE OR PERF SIZE (in)	SCREEN DIAM. OR PERF LENGTH (in)	SCREEN TYPE OR NUMBER PERF (per round/interval)
+2	560	Steel A53B	.375	16					

Well Head Configuration: Turbine Discharge Head Access Port Provided? ☒Yes ☐No

Casing Joint Type: Welded Perforator Used: No

Was a Surface Seal Installed? ☒Yes ☐No Depth of Surface Seal: 560 feet Drive Shoe? ☐Yes ☒No

Surface Seal Material Placement Method: Pumped

Was a temporary surface casing used? ☐Yes ☒No If yes, depth of casing: ____ feet diameter: ____ inches

DEPTH (feet)		SURFACE SEAL / INTERVAL SEAL / FILTER PACK / PACKER INFORMATION		
FROM	TO	SEAL MATERIAL, FILTER PACK and PACKER TYPE and DESCRIPTION	Quantity of Material Used (if applicable)	GROUT DENSITY (lbs./gal., # bag mix, gal./sack etc.)
260	560	Cement Grout	18 cu. yds	19.15 lbs/gal
0	76	Cement Grout	4 3/4 cu. yds	19.15 lbs/gal

Well Development and Well Yield Test Information

DATE	METHOD	YIELD	Units Check One		DRAWDOWN (ft)	TIME PUMPED (hrs & min)
			GPM	CFS		
Sept. 27	Air Lift	1000	✓			4 hrs
Sept. 29	Pump Test	2350	✓		271'	27 hrs

Pump (Permanent)

Pump Description: Line Shaft Turbine Horsepower: 300 Pump Intake Depth: 500 feet

Approximate Maximum Pumping Rate: 2200 GPM Well Disinfected upon Completion? ☒Yes ☐No

Comments Description of construction activity, additional materials used, problems encountered, extraordinary Circumstances, abandonment procedures. *Use additional well data form for more space.*

On grout seal we set 546' of 2" Trimmie line and started pumping. Line plugged after 18 cu. yds were pumped 8:00 P.M. So we rescheduled for next day. Could only get Trimmie to 76'. Pumped 4 3/4 cu yds more.

Well Driller Statement This well was drilled and constructed under my supervision, according to applicable rules and regulations, and this report is complete and correct to the best of my knowledge and belief.

Name ANZALONE WELL SERVICE License No. 749

(Person, Firm, or Corporation - Print or Type)

Signature Bryan Anzalone Date Oct 15, 2005

(Licensed Well Driller)

Proof of Appropriation
on
Application No. 15128

Proof of Appropriation on Water for Domestic and Municipal Purposes

STATE OF UTAH

Do not fill out this blank until you have read carefully the pamphlet on "Rules and Regulations" and Instructions in the body and on the back hereof.

1. *The name of the appropriator is* U. S. Government, War Department
2. *The post-office address of the appropriator is* Deseret Chemical Warfare Depot, St. John, Utah
3. *The quantity of water appropriated is* 1.63 *second-feet or* .... *acre-feet* OK
(See paragraph 4 under "Rules and Regulations" on page 4 hereof)
4. *The water is used each year from* January (Month) 1 (Day) *to* December (Month) 31 (Day) *incl.,*
and stored each year (if stored) from .... (Month) (Day) *to* .... (Month) (Day) *incl.*
5. *The drainage area to which the direct source of supply belongs is* Great Salt Lake (Leave Blank)
6. *The direct source of supply is*† Underground Water (Name of stream or other source)
which is tributary to ...., *tributary to* ....

†NOTE—If water is diverted from a well, an underground drain or a tunnel, the source should be designated as "Underground Water" in the first space and the remaining spaces should be left blank. If the source is a stream, a spring, a spring area, or a surface drain, so indicate in the first space, giving its name, if named, and in the remaining spaces designate the stream channels to which it is tributary, even though the water may sink, evaporate, or be diverted before reaching said channels. If water from a spring flows in a natural surface channel before being diverted, the direct source should be designated as a stream and not a spring.

7. *The point of diversion from ~~stream~~, ~~spring~~, ~~spring area~~, ~~drain~~, well (~~flowing~~ or pump), ~~tunnel~~, or* .... (Strike words not needed) *is in* Tooele *county, situated at a point** Well No. 1 - 1534 ft. South and 1957 ft. East of N.W. corner Sec. 5T6S,R4W, SLM, .81 sec. ft.; well No. 2, 1981 ft. South and 2214 ft. East of N. W. corner, Sec. 5T6S, R4W, SLM, .82 sec. ft.

*NOTE—Give the location of the point at which the water is first diverted from its source or channel with reference to a United States survey corner or mineral monument. In case of storage on the natural channel of source of supply, describe the point of intersection of stream bed with the center line of impounding dam. If a spring area, describe the point at which water is collected and diverted therefrom, and under General Remarks give a description by metes and bounds of said area.

8. *The diverting and carrying works consist of* two pump wells, #1-404' deep, #2-428' deep, fully cased with 12" #8 gauge steel casing with screw joints; two Byron-Jackson 12 stage deep well turbine pumps; 5846' of 8" pipe, and two 500,000 gallon concrete lined reservoirs.
9. *The length of the diverting channel, exclusive of laterals, is* 6678 *feet*
10. *The top width of the diverting channel is (if a ditch)* .... *feet*
11. *The bottom width of the diverting channel is (if a ditch)* .... *feet*
12. *The depth of water in the diverting channel is (if a ditch)* .... *feet*
13. *The width of the diverting channel is (if a flume)* .... *feet*
14. *The depth of water in the diverting channel is (if a flume)* .... *feet*
15. *The diameter of the diverting channel is (if a pipe)* 12 inch casing, 8" pipe *inches*
16. *The grade of the diverting channel is* vertical and rise 27.6 *feet per thousand*
17. *The place where the water is used is* Housing, shops, and storage areas, located in Sections 4, 5, 6, 7, 8, 9, 17, 18, and 20 T6S, R4W and Sections 11, and 12, T6S, R5W, SLM, all within Deseret Chemical Warfare Depot. The points of rediversion from the equalizing reservoirs are: Reservoir #1, ~~S3422~~ 3316 ft., and E 6327 ft., and Reservoir #2, S 3370 ft., and E 6428 ft., 5564 both of NW corner Sec. 5, T6S, R4W, SLM.

NOTE—Give place of use by legal subdivisions of section, township, and range of United States land survey, also by name if use is in town or city. If equalizing or distributing reservoir is used, give location of point of diversion therefrom by reference to a United States survey corner or mineral monument.

18. *Construction of works was commenced** 20 January *19* 44, *and completed* 30 August *19* 44.
*Date of first work subsequent to approval of Application. (See also the note under General Remarks.)
19. *Works were first used to convey water* See General Remarks, *19* ....
20. *Water was measured by* B. F. Lofgren (Name of hydrographer) *Date* September 22 & 23 *19* 44.
21. *Water was measured by ~~vessel~~, ~~weir~~, reservoir capacity, ~~or by~~*‡ .... (Strike words not needed)

‡(Give sufficient data under General Remarks to enable State Engineer to check the water measurements. It is necessary that the results of a series of such measurements be given.)

GENERAL REMARKS

NOTE—Give detailed description of the diverting and carrying works, tracing the water from point of diversion to place of use; give length and dimensions of each type of diverting channel. If all works necessary to apply the water to use were constructed prior to the time of approval of the Application herein described, so indicate and give a history of the development work. Name other rights, if any, to which this water is supplemental; also, name other rights, if any, the owners of which use these same works as a means of diversion and conveyance. If other uses incidental to the principal use are included in this proof, give period and extent of such uses.

From the two wells, described in paragraphs 7 and 8, water is diverted from the alluvial fill below the mouth of Ophir Canyon by means of Byron-Jackson deep well turbine pumps, each driven by a 60 H.P., 440 volt, 3 phase motor. From Well No. 1, the water flows 515 ft. to the pump house at Well No. 2. Here the water from both wells flows through a recording Sparling meter, thence 5331 ft. in an 8 inch steel pipe, to the equalizing reservoirs. It is rediverted from the reservoirs and used for domestic and fire control purposes as described in paragraph 17. There is an 8 inch bypass line which connects the pump discharge line directly with the distribution system to permit delivery to the system directly from the pumps. There is also a 3 inch lateral which connects directly to the pump discharge line. Water is diverted daily to keep the Reservoirs filled. The logs of the wells and the design of the reservoirs are shown on the attached sheet.

Construction of the system was commenced in May 1942; it was put into use in October 1942, and was completed August 30, 1944. The rate of diversion from each well was measured September 22 and 23, 1944, by the following method:

(1) Computing a capacity table for Reservoir No. 1, given on the attached sheet.
(2) Pumping each well separately into Reservoir No. 1 for a measured length of time.
(3) Measuring the gauge height at the beginning and end of the pumping test, and computing the gain in storage.
(4) Computing the rate of pumping of each well. The measurements made are as follows:

PUMPING TEST WELL NO. 1

Date	Hour	M.P.* to W.S. ft.	Gauge ft.	Capacity gals.
Sept. 22	11:00 A	5.27	15.03	336,091 ✓
Sept. 22	3:00 P ✓	3.37	16.93	424,194 ✓
Diff.	240 min. ✓	1.90	1.90	88,103

.818 Sec ft

Rate of pumping - Well No. 1 = 367 GPM**

Static water level was 285 ft. below pump house floor before and after pumping. During pumping the level remained at 290 ft., measured by air gauge.

PUMPING TEST WELL NO. 2

Date	Hour	M.P.* to W.S. ft.	Gauge ft.	Capacity gals.
Sept. 23	11:19A	4.385	15.915	377,128 ✓
Sept. 23	3:11P	2.535	17.765	462,913 ✓
Diff.	232 Min. ✓	1.850	1.850	85,785 ✓

.824 Sec ft

Rate of pumping - Well No. 2 = 370 GPM**

Static water level was 288 ft. below pump house floor before and after pumping. During pumping the level remained at 295 ft., measured by air gauge.

* NOTE: - M.P. = S.W. rim of manhole, 20.3 ft. above floor of reservoir.

** NOTE: - The pump meter showed Well No. 1 pumped 362 GPM; Well No. 2 pumped 368 GPM.

Each pump is set on a concrete base, having a slot in the side through which an air line passes from an air gauge into the well. A permanent bench mark at Well No. 1 is the pump house concrete floor at elevation 5398.72. A permanent measuring point is the bottom of the slot in the side of the concrete base, elevation 5399.32 ft. A permanent bench mark at Well No. 2 is the pump house concrete base, elevation 5399.55. A permanent measuring point is the bottom of the slot in the side of the concrete base, elevation 5399.73 ft.

10. **TUNNEL:** It is timbered, tiled, piped, open, bulkheaded, covered or..........
(Strike words not needed)

(a) Dimensions..........; total length..........; temperature of water..........°F.

(b) Position of water bearing stratum or strata with reference to mouth of tunnel..........

....

....

(c) Log of tunnel..........

....

....

....

11. **GENERAL REMARKS:** (Note any general or detailed information not covered above.)

(Log of Well Continued)

186' to 290'-Loose gravel and fine sand from 290' to 335 '-Coarse gravel from 335' to 339'-Fine gravel and Sand from 339' to 404'.

Casing was perforated from 290 feet to 404 feet.
Perforations--421 perforations, 4" by ½"

STATE OF UTAH,
COUNTY OF Salt Lake } ss.

I, H M Robinson & Son, being first duly sworn, do hereby certify that I am the driller of the aforesaid well or tunnel who furnished the foregoing statement of facts; that I have read said statement and each and all of the items therein contained are true to the best of my knowledge and belief.

H M Robinson & Son
Driller
By- D V Robinson

Subscribed and sworn to before me this 1st day of July, 1942.

Notary Public

(SEAL)

My Commission Expires:

April 28, 1944

Listed on well record
Listed by counties
Copied M.V. 4-7-43
Exam. & Recorded N.H.Y. 3-23-43
Exam. for filing J.O.W. 4-7-43
Final Copy checked M.V. 4-9-43
Platted & No. Assigned
Indexed M.V. 4-7-43
Engr. tied well
Engr. set BM
Well No.

PAGE (Leave Blank)

Report No. 2584
Filed July 1, 1942
Rec. By Counter
Ret'd

Report of Well and Tunnel Driller

STATE OF UTAH

(Separate report shall be filed for each well or tunnel)

GENERAL INFORMATION:

Report of well or tunnel driller is hereby made and filed with the State Engineer, in accordance with Sections 100-3-22, Revised Statutes of Utah 1933, as amended by Session Laws of 1935. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of well or tunnel. Failure to file such report constitutes a misdemeanor.)

1. Name and address of ~~person~~, company ~~or corporation boring~~ or drilling well or ~~tunnel~~ (Strike words not needed)
   H. M. Robinson & Son, 1940 So. 11th East, Salt Lake City, Utah.
2. Name and address of owner of well o~~r tunnel~~ United States Army, Deseret Chemical War-fare Depot (Strike words not needed)
   District Engineer, U. S. Engineers, 32 East Exchange Pl., Salt Lake City, Ut.
3. Source if supply is in Tooele County;
   drainage area; (Leave blank) artesian basin (Leave blank)
4. The number of approved application to appropriate water is 15128 Well No. 1
5. Location of well o~~r mouth of tunnel~~ is situated at a point S. 1534 ft. & E. 1957 ft. from the NW Cor. of Sec. 5, T. 6 S., R. 4 W., SLB&M.
   (Describe by course and distance with reference to U. S. Government Survey Corner — Copy description from well owner's approved application)
6. Date on which work on well or ~~tunnel~~ was begun May 18, 1942 (Strike words not needed)
7. Date on which work on well or ~~tunnel~~ was completed or ~~abandoned~~ June 26, 1942 (Strike words not needed)
8. Maximum quantity of water flowing, pumped or dipped on completion of well or tunnel in sec. (Strike words not needed)
   ft.; or in gals. per minute; Date

DETAIL OF COLLECTING WORKS:

9. WELL: It is a drilled, d~~ug, flowing~~ or pump well. Temperature of water °F. (Strike words not needed)
   (a) Total depth of well is 404 ft. below ground surface.
   (b) If flowing well, give water pressure (hydrostatic head) above ground surface ft.
   (c) If pump well, give depth from ground surface to water surface before pumping ; during pumping
   (d) Size and kind of casing 12½", 8 thread, 50 lb. per foot, Oil Well Casing (If only partially cased, give details)
   (e) Depth to water bearing stratum 290 feet to 404 feet (If more than one stratum, give depth to each)
   (f) If casing is perforated, give depth from ground surface to perforations 290 feet
   (g) Log of well Brown Clay from 0 to 26'-Clay & Gravel from 26' to 31'-Brown Clay from 31' to 36 '-Gravel from 36' to 39'-Yellow Clay from 39' to 42'-Muddy gravel from 42' to 86'-Gray Clay 86' to 88'-Gravel & Yellow Clay from 88' to 97'-Yellow Clay from 97 to 102'-Gravel & Yellow Clay from 102' to 155'-Yellow Clay with a little gravel from 155' to 162'-Gravel & Clay from 162' to 182'-Hard fine gravel from 182' to 186'-Gravel & Yellow Clay from
   (h) Well was equipped with cap, valve, or to control flow. (Strike words not needed)

(Over)

10. **TUNNEL:** It is timbered, tiled, piped, open, bulkheaded, covered or....................
(Strike words not needed)

(a) Dimensions....................; total length....................; temperature of water....................°F.

(b) Position of water bearing stratum or strata with reference to mouth of tunnel....................

....

....

(c) Log of tunnel....................

....

....

....

11. **GENERAL REMARKS:** (Note any general or detailed information not covered above.)

STATE OF UTAH,
COUNTY OF Salt Lake } ss.

I, Wm Robinson & Son By DeVere Robinson, being first duly sworn, do hereby certify that I am the driller of the aforesaid well or tunnel who furnished the foregoing statement of facts; that I have read said statement and each and all of the items therein contained are true to the best of my knowledge and belief.

Wm Robinson & Son
By DeVere Robinson
Driller

Subscribed and sworn to before me this 6 day of Oct. 1942

Verdie A. White
Notary Public

(SEAL)

My Commission Expires:
April 28, 1944

Listed on well record
Listed by counties
Copied M.V. 4-7-43
Exam. & Recorded [illegible] 3-23-43
Exam. for filing J.A.W. 4-7-43
Final Copy checked M.V. 4-7-43
Platted & No. Assigned
Indexed M.V. 4-7-43
Engr. tied well
Engr. set BM
Well No.

PAGE
(Leave Blank)

Report No. 2742
Filed Oct. 5, 1942
Rec. By Counter
Ret'd

Report of Well and Tunnel Driller

STATE OF UTAH

(Separate report shall be filed for each well or tunnel)

GENERAL INFORMATION:

Report of well or tunnel driller is hereby made and filed with the State Engineer, in accordance with Sections 100-3-22, Revised Statutes of Utah 1933, as amended by Session Laws of 1935. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of well or tunnel. Failure to file such report constitutes a misdemeanor.)

1. Name and address of person, ~~company or corporation boring~~ or drilling well ~~or tunnel~~ (Strike words not needed) Wm Robinson & Son - 1940 So 11th East St, S. L. City

2. Name and address of owner of well ~~or tunnel~~ (Strike words not needed) Deseret Chemical Warfare Depot, U S Army - St. John Utah

3. Source if supply is in Tooele County;

(Leave blank) drainage area; (Leave blank) artesian basin

4. The number of approved application to appropriate water is 15128 Well No. 2

5. Location of well ~~or mouth of tunnel~~ is situated at a point S. 1981 ft. & E. 2214 ft. from the NW Cor. of Sec. 5, T. 6 S., R. 4 W., SLB&M.

(Describe by course and distance with reference to U. S. Government Survey Corner — Copy description from well owner's approved application)

6. Date on which work on well ~~or tunnel~~ was begun (Strike words not needed) August 6, 1942

7. Date on which work on well ~~or tunnel was completed or~~ abandoned (Strike words not needed) Sept. 5, 1942

8. Maximum quantity of water flowing, pumped or dipped on completion of well or tunnel in sec. (Strike words not needed) ft.; or in gals. per minute; Date

DETAIL OF COLLECTING WORKS:

9. WELL: It is a drilled, ~~dug, flowing or~~ pump well. (Strike words not needed) Temperature of water No water °F.

(a) Total depth of well is 231 ft. below ground surface.

(b) If flowing well, give water pressure (hydrostatic head) above ground surface ft.

(c) If pump well, give depth from ground surface to water surface before pumping ; during pumping

(d) Size and kind of casing 15½" stal Casing — 12½" steel Casing (If only partially cased, give details)

(e) Depth to water bearing stratum (If more than one stratum, give depth to each)

(f) If casing is perforated, give depth from ground surface to perforations No Perforations

(g) Log of well 0'-20' - Soft sandy Soil; 20' to 65' Gravel and Boulders; 65' to 68' Red Clay; 68' to 211' Gravel and Boulders; 211' to 217' Cemented Conglomerate; 217' to 224' Loose Fine Gravel; 224' to 228' Cemented Conglomerate; 228-231 Fine loose gravel

(h) Well was equipped with cap, valve, or to control flow. (Strike words not needed)

(Over)

10. **TUNNEL:** It is timbered, tiled, piped, open, bulkheaded, covered or..........
(Strike words not needed)

(a) Dimensions..........; total length..........; temperature of water..........°F.

(b) Position of water bearing stratum or strata with reference to mouth of tunnel..........

....

....

(c) Log of tunnel..........

....

....

....

11. **GENERAL REMARKS:** (Note any general or detailed information not covered above.)

California
STATE OF [illegible],
COUNTY OF Los Angeles, } ss.

I, W. L. Doig, being first duly sworn, do hereby certify that I am the driller of the aforesaid well or tunnel who furnished the foregoing statement of facts; that I have read said statement and each and all of the items therein contained are true to the best of my knowledge and belief.

ROSCOE MOSS COMPANY
By W L Doig Secretary

Subscribed and sworn to before me this..........day of.........., 194.......

....
Notary Public

NOTARY [illegible] and for the
County of [illegible]
My Comm[illegible]

(SEAL)

My Commission Expires:

....

Listed on well record........................
Listed by counties ....
Copied M.V. 4-7-43........................
Exam. & Recorded NTY 3-23-43........................
Exam. for filing J.A.W. 4-2-43
Final Copy M.V. 4-7-43........................
Plotted & ....
Indexed M.V. 4-7-43........................
Engr. tied well ....
Engr. set Bill........................
Well No. ....

PAGE............................
(Leave Blank)

Report No. 2866
Filed Feb. 2, 1943
Rec. By mail
Ret'd 2354

Report of Well and Tunnel Driller

STATE OF UTAH

(Separate report shall be filed for each well or tunnel)

GENERAL INFORMATION:

Report of well or tunnel driller is hereby made and filed with the State Engineer, in accordance with Sections 100-3-22, Revised Statutes of Utah 1933, as amended by Session Laws of 1935. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of well or tunnel. Failure to file such report constitutes a misdemeanor.)

1. Name and address of ~~person, company or~~ corporation boring or drilling well ~~or tunnel~~ (Strike words not needed)
Roscoe Moss Company, 4360 Worth St. Los Angeles Calif.

2. Name and address of owner of well ~~or tunnel~~ (Strike words not needed) US Gov. War Dept Army
St John Chem. Warfare Ammunition Storage Depot. St. Johns Utah

3. Source if supply is in........................ Tooele ....County;

.... (Leave blank) drainage area;........................ artesian basin
Well No. 2 (Leave blank) ~~Robison Drilling Co~~

4. The number of approved application to appropriate water is/ 15128 .... ~~Had the original cont.~~

5. Location of well ~~or mouth of tunnel~~ is situated at a point Within the confines of the Chemical War fare Depot at St Johns, Utah
Well No. 2. S. 1981 ft. & E. 2214 ft. from the NW Cor. of Sec. 5, T. 6 S., R. 4 W., SLB&M.
(Describe by course and distance with reference to U. S. Government Survey Corner — Copy description from well owner's approved application)

6. Date on which work on well ~~or tunnel~~ was begun Unknown. We started 9/5/42 (Strike words not needed)

7. Date on which work on well or tunnel was completed or ~~abandoned~~ Oct. 2, 1942 (Strike words not needed)

8. Maximum quantity of water flowing, pumped or dipped on completion of well or tunnel in sec. (Strike words not needed)
ft........................; or in gals. per minute........................; Date........................

DETAIL OF COLLECTING WORKS:

9. WELL: It is a drilled, ~~dug, flowing or pump~~ well. Temperature of water........................°F. (Strike words not needed)

(a) Total depth of well is 428 ft. below ground surface.

(b) If flowing well, give water pressure (hydrostatic head) above ground surface........................ft.

(c) If pump well, give depth from ground surface to water surface before pumping
287'........................; during pumping........................

(d) Size and kind of casing 12" #10 ga, Double Hard Red Steel (If only partially cased, give details)

(e) Depth to water bearing stratum See log attached (If more than one stratum, give depth to each)

(f) If casing is perforated, give depth from ground surface to perforations 312' &
cut from 312' to 412' - 6 - 5/8" x 4" holes every 10"

(g) Log of well See log attached
....
....
....
....

(h) Well was equipped with cap, valve, or........................to control flow. (Strike words not needed)

(Over)

15-1774 15-136

Form 113—5M—12-60

Examined Dec 4, 73 WO
Recorded: B. C. Dec 4, 73 T. B. WO
Inspection Sheet
Copied 12-5-73 B.M.

REPORT OF WELL DRILLER

STATE OF UTAH

Application No. 43 13 3 (15-1774)
Claim No.
Coordinate No. #1 (C-5-5) 5 adb

GENERAL STATEMENT: Report of well driller is hereby made and filed with the State Engineer, in accordance with the laws of Utah. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of the well. Failure to file such reports constitutes a misdemeanor.)

(1) WELL OWNER:

Name Hogar Brothers
Address Box F64 Stockton Utah

(2) LOCATION OF WELL:

County Tooele Ground Water Basin (leave blank)

~~North~~ South 1650 feet, West 1320 feet from NE Corner of Section 5, T. 5 S, R. 5 W, SLBM (strike out words not needed)

(3) NATURE OF WORK (check):

New Well ☒ Replacement Well ☐ Deepening ☐ Repair ☐ Abandon ☐

If abandonment, describe material and procedure:

(4) NATURE OF USE (check):

Domestic ☐ Industrial ☐ Municipal ☐ Stockwater ☐
Irrigation ☒ Mining ☐ Other ☐ Test Well ☐

(5) TYPE OF CONSTRUCTION (check):

Rotary ☐ Dug ☐ Jetted ☐
Cable ☒ Driven ☐ Bored ☐

(6) CASING SCHEDULE:

Threaded ☐ Welded ☒

12" Diam. from 0 feet to 209 feet Gage .250
" Diam. from feet to feet Gage
" Diam. from feet to feet Gage

New ☐ Reject ☐ Used ☐

(7) PERFORATIONS:

Perforated? Yes ☒ No ☐

Type of perforator used Blade
Size of perforations 4 inches by 5 inches
20 perforations from 155 feet to 168 feet
30 perforations from 125 feet to 143 feet
25 perforations from 76 feet to 115 feet
20 perforations from 51 feet to 67 feet
perforations from feet to feet

(8) SCREENS:

Well screen installed? Yes ☐ No ☐

Manufacturer's Name
Type Model No.
Diam. Slot size Set from ft. to
Diam. Slot size Set from ft. to

(9) CONSTRUCTION:

Was well gravel packed? Yes ☐ No ☒ Size of gravel:
Gravel placed from feet to feet
Was a surface seal provided? Yes ☐ No ☒
To what depth? feet
Material used in seal:
Did any strata contain unusable water? Yes ☐ No ☒
Type of water: Depth of strata
Method of sealing strata off:

Was surface casing used? Yes ☐ No ☐
Was it cemented in place? Yes ☐ No ☐

(10) WATER LEVELS:

Static level 10 feet below land surface Date Aug 22, 73
Artesian pressure feet above land surface Date

LOG RECEIVED
DIVIS... WATER ...

(11) FLOWING WELL:

Controlled by (check) Valve ☐ Cap ☐ Plug ☐ No Control ☐
Does well leak around casing? Yes ☐ No ☐

(12) WELL TESTS:

Drawdown is the distance in feet the water level is lowered below static level.

Was a pump test made? Yes ☐ No ☐ If so, by whom?
Yield: 1140 gal./min. with 77 feet drawdown after 21 hours
" " " "
" " " "
Bailer test gal./min. with feet drawdown after hours
Artesian flow g.p.m. Date
Temperature of water Was a chemical analysis made? No ☒ Yes ☐

(13) WELL LOG:

Diameter of well 12 inches
Depth drilled 209 feet. Depth of completed well 209 feet.

NOTE: Place an "X" in the space or combination of spaces needed to designate the material or combination of materials encountered in each depth interval. Under REMARKS make any desirable notes as to occurrence of water and the color, size, nature, etc., of material encountered in each depth interval. Use additional sheet if needed.

DEPTH		MATERIAL										REMARKS
From	To	Clay	Silt	Sand	Gravel	Cobbles	Boulders	Hardpan	Conglomerate	Bedrock	Other	
0	3										X	Topsoil
20	30	X										Surface water
30	43	X										Gray
43	51	X										Blue
51	54				X							Gravel 2" To 3"
54	56	X										
56	67				X							Gravel 2" 5'30
67	70			X								
70	76	X										
76	77				X							
77	82	X										
82	87			X	X							
87	97	X										
97	98				X							
98	102	X										
102	103				X							
103	115	Y			X							
115	123				X							
123	143	X			X							
143	144			X								Course sand
144	145	X										
145	146			Y								course sand
146	158	X										
158	168	X			X							
168	191	X										
191	192			X								
192	207	X						X				Laminated Hardpans And Clay
207	209	X										Hardpans approx 12" Thick

Work started July 7, 1973 Completed Aug 22, 1973

(14) PUMP:

Manufacturer's Name
Type: H. P.
Depth to pump or bowles feet

Well Driller's Statement:

This well was drilled under my supervision, and this report is true to the best of my knowledge and belief.

Name Caldwell Drilling (Person, firm, or corporation) (Type or print)
Address St John Utah 84069
(Signed) Reid Caldwell (Well Driller)
License No. 314 Date Sept 5, 1973

USE OTHER SIDE FOR ADDITIONAL REMARKS

[redacted]

16-136
&
A28985 & 8615-137

Form 118 2M 4-60
Examined Jan 12-1961 ACT
Recorded: B. 01-13-61 ACT T. B. ACT
[redacted] Sheet 19 1-20-61
[redacted] 1-26-61 Afc

REPORT OF WELL DRILLER
STATE OF UTAH

Application No. a-3669 (Well #2)
Claim No.
Coordinate No. (C-4-5)32 dde

GENERAL STATEMENT: Report of well driller is hereby made and filed with the State Engineer, in accordance with the laws of Utah. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of the well. Failure to file such reports constitutes a misdemeanor.)

(1) WELL OWNER:
Name Hogan Bros. Farm (Utah Water & Power)
Address Stockton, Utah

(2) LOCATION OF WELL:
County Tooele   Ground Water Basin (leave blank)
North/South ---- feet, ~~East~~ West 1320 feet from SE Corner
of Section 32, T. 4 ~~N~~ S, R. 5 ~~E~~ W, SLBM / USM (strike out words not needed)

(3) NATURE OF WORK (check):
New Well ☒
Replacement Well ☐ Deepening ☐ Repair ☐ Abandon ☐
If abandonment, describe material and procedure:

(4) NATURE OF USE (check):
Domestic ☐ Industrial ☐ Municipal ☐ Stockwater ☐
Irrigation ☒ Mining ☐ Other ☐ Test Well ☐

(5) TYPE OF CONSTRUCTION (check):
Rotary ☐ Dug ☐ Jetted ☐
Cable ☒ Driven ☒ Bored ☐

(6) CASING SCHEDULE:
Threaded ☐ Welded ☐
12" Diam. from ground feet to 96 feet Gage
" Diam. from feet to feet Gage
" Diam. from feet to feet Gage
New ☒ Reject ☐ Used ☐

(7) PERFORATIONS:
Perforated? Yes ☒ No ☐
Type of perforator used at 42 ft.
Size of perforations inches by inches
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet

(8) SCREENS:
Well screen installed? Yes ☐ No ☒
Manufacturer's Name
Type Model No.
Diam. Slot size Set from ft. to ft.
Diam. Slot size Set from ft. to ft.

(9) CONSTRUCTION:
Was well gravel packed? Yes ☐ No ☐ Size of gravel:
Gravel placed from feet to feet
Was a surface seal provided? Yes ☐ No ☐
To what depth? feet
Material used in seal:
Did any strata contain unusable water? Yes ☐ No ☐
Type of water: Depth of strata
Method of sealing strata off:

Was surface casing used? Yes ☐ No ☐
Was it cemented in place? Yes ☐ No ☐

(10) WATER LEVELS:
Static level feet below land surface Date
Artesian pressure feet above land surface Date

LOG RECEIVED:
RECEIVED
DEC 27 1960
STATE ENGINEER
COUNTER

(11) FLOWING WELL:
Controlled by (check) Valve ☐
Cap ☐ Plug ☐ No Control ☐
Does well leak around casing? Yes ☐
No ☐

(12) WELL TESTS:
Drawdown is the distance in feet the water level is lowered below static level.
Was a pump test made? Yes ☐ No ☒ If so, by whom?
Yield: gal./min. with feet drawdown after hours
" " " "
" " " "
Bailer test gal./min. with feet drawdown after hours
Artesian flow g.p.m. Date
Temperature of water Was a chemical analysis made? No ☐ Yes ☐

(13) WELL LOG:
Diameter of well 12 inches
Depth drilled 96 feet. Depth of completed well feet.

NOTE: Place an "X" in the space or combination of spaces needed to designate the material or combination of materials encountered in each depth interval. Under REMARKS make any desirable notes as to occurrence of water and the color, size, nature, etc., of material encountered in each depth interval. Use additional sheet if needed.

DEPTH		MATERIAL										REMARKS
From	To	Clay	Silt	Sand	Gravel	Cobbles	Boulders	Hardpan	Conglomerate	Bedrock	Other	
0	34	x										
34	38				x							
38	42			x								
42	96	x			x							

Work started Dec. 5, 1959 Completed Dec. 10, 1959

(14) PUMP:
Manufacturer's Name
Type: H. P.
Depth to pump or bowles feet

Well Driller's Statement:
This well was drilled under my supervision, and this report is true to the best of my knowledge and belief.
Name Robinson Drilling Co. (Person, firm, or corporation) (Type or print)
Address 1940 So. 11th East, Salt Lake City
(Signed) D. C. Robinson (Well Driller)
License No. 10 Date December 30, 1960

USE OTHER SIDE FOR ADDITIONAL REMARKS

MICROFILMED

Form 113—5M—12-60

Examined 6-24-70 V.F.O.
Recorded: B. C. 6-24-70 V.F.O. T. B. V.F.O.
Inspection Sheet 6-26-70 B.M.
Copied

REPORT OF WELL DRILLER

STATE OF UTAH

A-28985
#2 A-3669
Application No. ~~[illegible]~~ (15-136)
Claim No.
Coordinate No. (C-4-5) 32ddc

GENERAL STATEMENT: Report of well driller is hereby made and filed with the State Engineer, in accordance with the laws of Utah. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of the well. Failure to file such reports constitutes a misdemeanor.)

(1) WELL OWNER:

Name Hogan, Brothers Farm
Address Stockton Utah

(2) LOCATION OF WELL:

County Tooele Ground Water Basin (leave blank)
North/South feet, ~~East~~/West 1320 feet from SE Corner
of Section 32, T 4 ~~N~~/S, R 5 ~~E~~/W SLBM ~~USM~~ (strike out words not needed)

(3) NATURE OF WORK (check):

New Well ☐
Replacement Well ☐ Deepening ☑ Repair ☐ Abandon ☐
If abandonment, describe material and procedure:

(4) NATURE OF USE (check):

Domestic ☐ Industrial ☐ Municipal ☐ Stockwater ☐
Irrigation ☑ Mining ☐ Other ☐ Test Well ☐

(5) TYPE OF CONSTRUCTION (check):

Rotary ☐ Dug ☐ Jetted ☐
Cable ☑ Driven ☐ Bored ☐

(6) CASING SCHEDULE:

Threaded ☐ Welded ☑
12" Diam. from 93 feet to 129 feet Gage 3/4
" Diam. from feet to feet Gage
" Diam. from feet to feet Gage
New ☑ Reject ☐ Used ☐

(7) PERFORATIONS:

Perforated? Yes ☑ No ☐
Type of perforator used Blade
Size of perforations 1/2 inches by 6 inches
180 perforations from 93 feet to 129 feet
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet

(8) SCREENS:

Well screen installed? Yes ☐ No ☑
Manufacturer's Name
Type Model No.
Diam. Slot size Set from ft. to
Diam. Slot size Set from ft. to

(9) CONSTRUCTION:

Was well gravel packed? Yes ☐ No ☑ Size of gravel:
Gravel placed from feet to feet
Was a surface seal provided? Yes ☑ No ☐
To what depth? feet
Material used in seal:
Did any strata contain unusable water? Yes ☐ No ☑
Type of water: Depth of strata
Method of sealing strata off:

Was surface casing used? Yes ☐ No ☑
Was it cemented in place? Yes ☑ No ☐

(10) WATER LEVELS:

Static level 22 feet below land surface Date 21 Mar 70
Artesian pressure feet above land surface Date

LOG RECEIVED:

(11) FLOWING WELL:

Controlled by (check) Valve ☐
Cap ☐ Plug ☐ No Control ☐
Does well leak around casing? Yes ☐
No ☐

(12) WELL TESTS:

Drawdown is the distance in feet the water level is lowered below static level.

Was a pump test made? Yes ☐ No ☑ If so, by whom?
Yield: gal./min. with feet drawdown after hours
" " " "
" " " "
Bailer test gal./min. with feet drawdown after hours
Artesian flow g.p.m. Date
Temperature of water Was a chemical analysis made? No ☐ Yes ☐

(13) WELL LOG:

Diameter of well 12 inches
Depth drilled 93 feet. Depth of completed well 129 feet.

NOTE: Place an "X" in the space or combination of spaces needed to designate the material or combination of materials encountered in each depth interval. Under REMARKS make any desirable notes as to occurrence of water and the color, size, nature, etc., of material encountered in each depth interval. Use additional sheet if needed.

DEPTH		MATERIAL										REMARKS
From	To	Clay	Silt	Sand	Gravel	Cobbles	Boulders	Hardpan	Conglomerate	Bedrock	Other	
93	98				✓							
98	103	✓										
103	125				✓							
125	129	✓										

Work started 21 Mar, 1970 Completed 4 April, 1970

(14) PUMP:

Manufacturer's Name
Type: H. P.
Depth to pump or bowles feet

Well Driller's Statement:

This well was drilled under my supervision, and this report is true to the best of my knowledge and belief.

Name Edwin Hale (Person, firm, or corporation) (Type or print)
Address 308 Gilchrist Dr Tooele Utah
(Signed) Edwin Hale (Well Driller)
License No. 38 Date May 21, 1970

USE OTHER SIDE FOR ADDITIONAL REMARKS

MICROFILMED

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n 8/17/39
Gnc B
Jan 8/17/39
signed
mR 8-13-41

PAGE.......................
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Report No. 491
Filed Aug. 25, 1939
Rec. By Mail 8/11/39
Rec. $1.00 Fee

Report of Well and Tunnel Driller

No fee

STATE OF UTAH

(Separate report shall be filed for each well or tunnel)

15-2330

GENERAL INFORMATION:

Report of well or tunnel driller is hereby made and filed with the State Engineer, together with a filing fee of $1.00, submitted in accordance with Sections 100-3-22 and 100-2-14, Revised Statutes of Utah 1933, as amended by Session Laws of 1935. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of well or tunnel. Failure to file such report constitutes a misdemeanor.)

1. Name and address of ~~person~~, company or ~~corporation boring~~ or drilling well or ~~tunnel~~ (Strike words not needed)
Chas. M. Erb Drilling Co. Ephraim, Utah

2. Name and address of owner of well ~~or tunnel~~ Snyder Mines Inc. (Strike words not needed)
Salt Lake City, Utah

3. Source of supply is in Tooele County;
.... drainage area; .... artesian basin
(Leave blank) (Leave blank)

4. The number of approved application to appropriate water is -12696
.oll # 2

5. Location of well ~~or mouth of tunnel~~ is situated at a point Approx. 150 ft. East of Co. road at crossing of Ophir Canyon (N 30° E 157 ft from [illegible] No. 1)
1140.2 Ft. No. & 1860.5 Ft. East from S. W. Corner of Sec. 28, Tp. 5 S. Rge 4 W.
(Describe by course and distance with reference to U. S. Government Survey Corner — copy description from well owners' approved application)

6. Date on which work on well ~~or tunnel~~ was begun May 12, 1937 (Strike words not needed)

7. Date on which work on well ~~or tunnel~~ was completed ~~or abandoned~~ May 18, 1937 (Strike words not needed)

8. Maximum quantity of water flowing, pumped or dipped on completion of well ~~or tunnel~~ in (Strike words not needed)
sec. ft.......................; or in gals. per minute 146; Date May 18, 1937

DETAIL OF COLLECTING WORKS:

9. WELL: It is a drilled, ~~dug, flowing~~ or pump well. Temperature of water Unknown ° F. (Strike words not needed)

(a) Total depth of well is 86 ft. below ground surface.

(b) Pressure in lbs. per sq. inch at ground surface if flowing well ....

(c) If pump well, give depth from ground surface to water surface before pumping 61'-6"; during pumping 77 ft.

(d) Size and kind of casing 12" 12 gauge double rivited
(If only partially cased, give details)

(e) Depth to water bearing stratum 71 ft.
(If more than one stratum, give depth to each)

(f) If casing is perforated, give depth from ground surface to perforations 68' to 80' 20 holes per ft. 80' to 84'6", 8 holes each 8"

(g) Log of well 0-2' top soil, 2'-71' yellow clay and gravel 71'-73' free gravel (1st water) 73'-75' broken black shale and clay 75'80' fractured black shale 80'-86' black shale

(h) Well was equipped with ~~cap, valve, or~~ Turbine pump to control flow. (Strike words not needed)

(Over)

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Report No. 502
Filed Aug. 25, 1939
Rec. By Mail 8/11/39
Rec. $1.00 Fee
No fee

Report of Well and Tunnel Driller
STATE OF UTAH

(Separate report shall be filed for each well or tunnel)

15-2330

GENERAL INFORMATION:

Report of well or tunnel driller is hereby made and filed with the State Engineer, together with a filing fee of $1.00, submitted in accordance with Sections 100-3-22 and 100-2-14, Revised Statutes of Utah 1933, as amended by Session Laws of 1935. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of well or tunnel. Failure to file such report constitutes a misdemeanor.)

1. Name and address of ~~person~~ company ~~or corporation boring or~~ drilling well ~~or tunnel~~ (Strike words not needed)
Chas. M. Erb Drilling Co. Ephraim Utah

2. Name and address of owner of well or ~~tunnel~~ (Strike words not needed) Snyder Mines Inc.
Salt Lake City, Utah

3. Source of supply is in Tooele County;
drainage area; (Leave blank) artesian basin (Leave blank)

4. The number of approved application to appropriate water is A-12696 Well # 1

5. Location of well or ~~mouth of tunnel~~ is situated at a point Approx. 200 ft. west of Co. road at crossing of Ophir Canyon
E. 1,782 ft. and N. 1,005 ft. from SW cor. Sec. 20 T.5S. R. 4 W. SLB&M
(Describe by course and distance with reference to U. S. Government Survey Corner — copy description from well owners' approved application)

6. Date on which work on well ~~or tunnel~~ was begun May 5, 1937 (Strike words not needed)

7. Date on which work on well or tunnel was completed ~~or abandoned~~ May 17, 1937 (Strike words not needed)

8. Maximum quantity of water ~~flowing~~ pumped ~~or siphoned~~ on completion of well ~~or tunnel~~ in (Strike words not needed)
sec. ft.; or in gals. per minute 178; Date May 17, 1937

DETAIL OF COLLECTING WORKS:

9. WELL: It is a drilled, dug, flowing or pump well. (Strike words not needed) Temperature of water ° F.

(a) Total depth of well is 90 ft. below ground surface.

(b) Pressure in lbs. per sq. inch at ground surface if flowing well

(c) If pump well, give depth from ground surface to water surface before pumping
61' 5"; during pumping 77'

(d) Size and kind of casing 12" 12 gauge double rivited
(If only partially cased, give details)

(e) Depth to water bearing stratum 67 ft.
(If more than one stratum, give depth to each)

(f) If casing is perforated, give depth from ground surface to perforations
perocorated from 67' to 88' 20 holes per ft.

(g) Log of well 0'-2' top soil 2'-67' yellow clay and gravel 67'-74' gravel (1st water) 74'-86' fractured black shale 86'-90' so ft black shale.

(h) Well was equipped with ~~cap, valve or~~ Turbine Pump to control flow. (Strike words not needed)

(Over)

Form 113—5M—12-60

15-163

Examined 12/31/63 ACT.
Recorded: B. 1-2-64 ACT. T. B. ACT
Inspection Sheet 1-3-64- [illegible]
Copied 1-6-64 R.S.

REPORT OF WELL DRILLER
STATE OF UTAH

Application No. 32974
Claim No.
Coordinate No. (C-5-5)4daa

GENERAL STATEMENT: Report of well driller is hereby made and filed with the State Engineer, in accordance with the laws of Utah. (This report shall be filed with the State Engineer within 30 days after the completion or abandonment of the well. Failure to file such reports constitutes a misdemeanor.)

(1) WELL OWNER:
Name Joe Sandini
Address STOCKTON UTAH

(2) LOCATION OF WELL:
County Tooele Ground Water Basin (leave blank)
South 2840 feet, West 550 feet from N.E. Corner
of Section 4, T. 5 S, R. 5 W SLBM (strike out words not needed)

(3) NATURE OF WORK (check):
New Well ☑
Replacement Well ☐ Deepening ☐ Repair ☐ Abandon ☐
If abandonment, describe material and procedure:

(4) NATURE OF USE (check):
Domestic ☑ Industrial ☐ Municipal ☐ Stockwater ☑
Irrigation ☑ Mining ☐ Other ☐ Test Well ☐

(5) TYPE OF CONSTRUCTION (check):
Rotary ☐ Dug ☐ Jetted ☐
Cable ☑ Driven ☐ Bored ☐

(6) CASING SCHEDULE:
Threaded ☐ Welded ☑
8" Diam. from 0 feet to 300 feet Gage .25
" Diam. from feet to feet Gage
" Diam. from feet to feet Gage
New ☑ Reject ☐ Used ☐

(7) PERFORATIONS:
Perforated? Yes ☑ No ☐
Type of perforator used Casing Ripper on Drill Stem
Size of perforations 3/4 inches by 10 inches
85 perforations from 164 feet to 249 feet
10 perforations from 282 feet to 290 feet
perforations from feet to feet
perforations from feet to feet
perforations from feet to feet

(8) SCREENS:
Well screen installed? Yes ☐ No ☐
Manufacturer's Name
Type Model No.
Diam. Slot size Set from ft. to
Diam. Slot size Set from ft. to

(9) CONSTRUCTION:
Was well gravel packed? Yes ☐ No ☑ Size of gravel:
Gravel placed from feet to feet
Was a surface seal provided? Yes ☐ No ☐
To what depth? feet
Material used in seal:
Did any strata contain unusable water? Yes ☐ No ☐
Type of water: Good Depth of strata
Method of sealing strata off:
Was surface casing used? Yes ☑ No ☐
Was it cemented in place? Yes ☐ No ☑

(10) WATER LEVELS:
Static level feet below land surface Date
Artesian pressure feet above land surface Date

LOG RECEIVED:
Dec-31-1963
ACT

(11) FLOWING WELL:
Controlled by (check) Valve ☑
Cap ☐ Plug ☐ No Control ☐
Does well leak around casing? Yes ☐
No ☑

(12) WELL TESTS:
Drawdown is the distance in feet the water level is lowered below static level.
Was a pump test made? Yes ☐ No ☑ If so, by whom?
Yield: gal./min. with feet drawdown after hours
Bailer test gal./min. with feet drawdown after hours
Artesian flow Estimated 650 g.p.m. Date Dec. 15 1963
Temperature of water Cool Was a chemical analysis made? No ☑ Yes ☐

(13) WELL LOG:
Diameter of well 8 inches
Depth drilled feet. Depth of completed well 300 feet.

NOTE: Place an "X" in the space or combination of spaces needed to designate the material or combination of materials encountered in each depth interval. Under REMARKS make any desirable notes as to occurrence of water and the color, size, nature, etc., of material encountered in each depth interval. Use additional sheet if needed.

DEPTH		MATERIAL										REMARKS
From	To	Clay	Silt	Sand	Gravel	Cobbles	Boulders	Hardpan	Conglomerate	Bedrock	Other	
0	5		w									
5	16	X										white clay
16	68	X										Dark mushy Small amount
88	96			X								Water Raised to 28ft. of water
96	110	X										Dark clay
110	115			X								
115	121	X										Dark clay
121	148	X		X								
148	164			X								
164	187				X							Small pea gravel - water comes 1FT Above Surf
187	210	X										
210	214				X							Fine Gravel - water 14" Above Surf
214	216	X										
216	249	X				X						gravel with Thin Layers of clay sill
249	270	X										Brown in color
270	282	X										Grey in color
282	290				X							Water Comes 30" above Surface
290	300	X										

Work started July 30, 1962 Completed 28 Sept, 1963

(14) PUMP:
Manufacturer's Name
Type: H. P.
Depth to pump or bowles feet

Well Driller's Statement:

This well was drilled under my supervision, and this report is true to the best of my knowledge and belief.

Name Henry Calvin Russell (Person, firm, or corporation) (Type or print)
Address ST. John UTAH
(Signed) Henry Calvin Russell (Well Driller)
License No. 74 Date Dec 27, 1963

USE OTHER SIDE FOR ADDITIONAL REMARKS

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OxyStream™

ADVANCED OXIDATION DITCH TECHNOLOGY

Furnished By:
WesTech Engineering, Inc.
3625 South West Temple
Salt Lake City, Utah
Phone: (801) 256-1000
Fax: (801) 265-1080

WESTECH AN EMPLOYEE OWNED COMPANY

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INTRODUCTION

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WESTECH

WESTECH ENGINEERING, INC. HISTORY

WesTech Engineering, Inc. is a progressive company which has grown to become one of the major suppliers of process equipment in the world today. It is an employee owned company, led by individuals with long experience in this industry.

Formed as a partnership in 1972 and incorporated in 1973, WesTech was created to supply sedimentation and filtration process equipment to municipalities and industry, as well as to provide specialty engineering services.

WesTech equipment has been installed at thousands of installations throughout the United States and internationally. WesTech has been a leader in the development of process equipment that improves efficiency, quality, and performance while lowering overall costs. All leading consultants have approved WesTech equipment for use on their projects.

WesTech has enjoyed steady growth since its founding and has maintained a financially sound position throughout. With an Employee Stock Ownership Plan (ESOP) holding a large part of the company's stock, WesTech employees have a strong commitment to the success of the company. WesTech's management is progressive and responsive to the needs of its customers, employees, and the industry at large. In 1995, WesTech achieved ISO 9001 Certification to assure quality products and services for our customers. The company is on record with Dun and Bradstreet; refer to their San Francisco office for a detailed report.

Industries using WesTech equipment include; municipal water and wastewater treatment, coal preparation, chemical processing, mining and metallurgical, pulp and paper, power generation, food processing, and a wide variety of others.

WesTech maintains representation throughout the United States and in many foreign countries for both municipal and industrial equipment lines. We invite your inquiry into our company, our capabilities, and our product line. We are eager to discuss how WesTech equipment can fully meet specific project requirements and provide many years of quality service.

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WESTECH
"We Guarantee Peace of Mind!"

ISO 9001:2000 CERTIFICATION

Certificate US95/0255

The most responsive supplier of products and services for liquid-solid separation and the treatment of water and wastewater.

WesTech Engineering, Inc. is certified to the ISO 9001:2000 standard with SGS Systems & Services Certification. SGS is an independent ISO registrar, who conducts regular audits of clients' management processes.

The significance of ISO 9001:2000 is that it not only ensures the consistency of quality practices, but requires continuous improvement of WesTech's entire management system. Certification therefore assures customers that 1) WesTech's products and services will consistently meet or exceed an internationally agreed-upon level of quality, and 2) proactive management practices will enable it to anticipate and address customers' future needs, while paying careful attention to existing installations.

Founded in 1973, WesTech has attained preferred-supplier status with an overwhelming majority of its worldwide customers. As a leading innovator in the development of equipment that lowers overall costs by improving efficiency, reliability, and performance, the firm has been approved by virtually all major consultants for their projects.

WesTech is an employee-owned company. Since the Employee Stock Ownership Plan holds a majority of the stock, design and support personnel are naturally committed to the success of their projects and customers. Attitudes, behaviors, and decisions are further shaped by WesTech's six core values, which are:

- Exhibit honesty and integrity
- Always do the right thing the first time
- Value our people and their families
- Take pride in our products
- Achieve productivity through hard work
- Provide superior service

The net result of WesTech's continuing ISO certification, combined with its distinctive ownership culture, is that customers can expect to be taken care of by exceptionally responsive associates who consistently deliver superior solutions. The company's stunning multi-year Customer Satisfaction rating of 95% is evidence of the power and effectiveness of this combination.

We invite you to learn more about our company, capabilities, and products - and then continually put us to the test. Find out for yourself why we say, "We not only guarantee our equipment, we guarantee peace of mind!"

TABLE OF CONTENTS

OxySTREAM^{TM} TREATMENT SYSTEM

WesTech Engineering, a leading supplier of wastewater treatment systems, is the exclusive licensee of the world's largest designer and supplier of slow speed surface aerators, Landustrie BV, Netherlands. Combining the experience of WesTech and Landustrie creates the most advanced oxidation ditch and clarification system in the wastewater treatment market. The OxyStream™ and COP™ Systems provide an integrated approach to highly effective, automated oxidation ditch and optimized clarifier technology for both municipal and industrial wastewater treatment applications.

OXYSTREAM™ DESIGN

The OxyStream™ design provides an integrated treatment system including process and system design, core equipment supply, control and management software, and process operations training. This integrated system always includes our mechanical warranty and process guarantee.

PROCESS SYSTEM

- OxyStream™ Process combines the technology of oxidation ditches with advanced biological nutrient removal systems in a continuous hydraulic loop.
- System geometry, equipment selection, and operational conditions are enhanced using WesTech's hydraulic model.
- The high efficiency LANDY™ aerators provide maximum turndown capabilities and greatest range of operation.
- The Clarifier Optimization Package (COP™) combines the key features of modern clarification into a single system. The net result:
  - Improved clarifier feed rate
  - Maximized sludge concentration
  - Minimized sludge pumping (savings of 50% and greater)
  - Rapid Sludge Withdrawl
  - Produces the cleanest possible secondary effluent
- Automated OxyStream™ Control System (AOCS™) designed to manage and automatically control the operation of the system.

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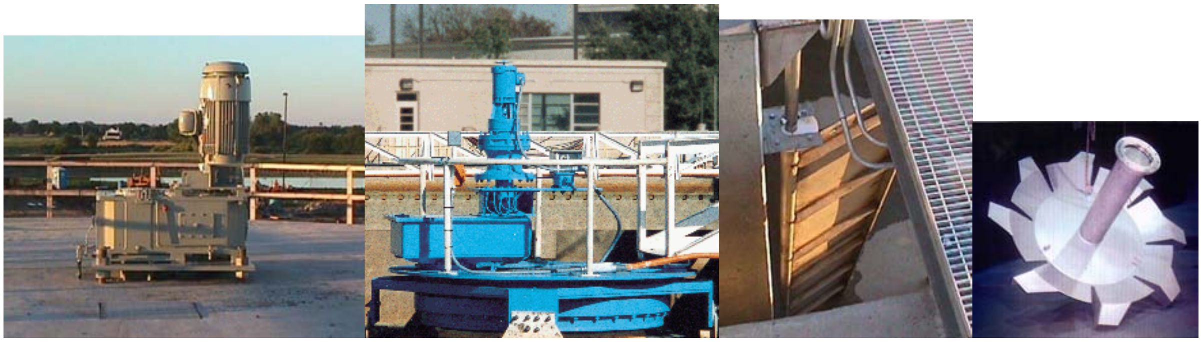
DESIGN KIT

- Comprehensive process evaluation and treatment solution analysis
- Hydraulic modeling of the biological process and secondary clarification as an integrated treatment solution
- Process Flow Diagrams
- Piping and Instrumentation Drawings
- System layout drawings, equipment arrangement drawings and loading details
- Recommended equipment and related electrical controls
- Customized AOCS™ control logic for enhanced treatment and energy savings
- Final evaluation of the complete design, backed by our Process Guarantee.

CORE EQUIPEMNT

- WesTech's Surface Aerator Series drive unit consisting of a helical geared, vertical type, gear reducer with integral dry-well and a premium efficient motor connected using a flexible high-speed coupling.



- LANDY™ Series low speed surface aerators, the most reliable and rugged, non-clogging impeller, with the industries highest oxygen transfer efficiency of 3.5~3.8 lbO_2/HP-hr. LANDY™ aerators have emerged as the most efficient surface aerator on the market. LANDY™ aerators can be made of either carbon steel or stainless steel with installed motor power up to 250 HP and impeller diameter up to 14 feet.
- OXYSTREAM™ Series Internal Nitrate Recycle Gate eliminates the need for auxiliary pumps and external piping.
- Secondary mixers to ensure proper solids suspension within the separate treatment zones. Mixers can either be vertical shaft or submersible type.
- Flow Boosters can be added to increase the turndown capabilities and process flexibility.
- WesTech's Industry Leading Precision Bearing Drive Unit provides a main bearing design life in excess of 100 years. The drives can be fully grease lubricated to minimize operator maintenance.
- The WesTech COP™ Clarifier, incorporates the latest advancements in energy dissipating inlets, flocculating feedwells, spiral blades and sludge withdrawl rings.
- AOCS™ proprietary software, with real-time monitoring and automated control.

TABLE OF CONTENTS

AOCS CONTROL AND MANAGEMENT SYSTEM

- AOCS™ provides fully automated real-time process control and power optimization for the OxyStream™ and COP™ System.
- AOCS™ evaluates key process parameters, compares the values against our proven operating algorithm and makes adjustments to the system to enhance treatment performance while saving energy.
- AOCS™ is a unique control and management system that ensures stable process performance and optimal energy efficiency during highly fluctuating operating conditions.

PROCESS EVALUATION AND SYSTEM CALIBRATION

- Along with the Core Equipment, the OxyStream™ and COP™ package includes operational guidance.
- After start-up and the process begins to operate at steady-state, we encourage you to send your operation data to WesTech. Our process engineers can evaluate the efficiency of the system. We evaluate the effluent performance, power usage, clarifier state point, condition of biomass and overall system mass balance. -
- Our process engineers will produce a formal recommendation for operational practices and control adjustments.

EFFLUENT GUARNATEE

The OxyStream™ and COP™ package comes complete with a Process Guarantee on the effluent in accordance with the design conditions and quality standards required by the customer.

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PRINCIPLE

The term “selector” was first used in the wastewater industry to describe the modification of the activated sludge process incorporating small zone(s) at the upstream end of the aeration basin where influent waste and return activated sludge are combined prior to entering the main aeration basin.

1. ANAEROBIC BIO-SELECTOR ZONE (SX-1)

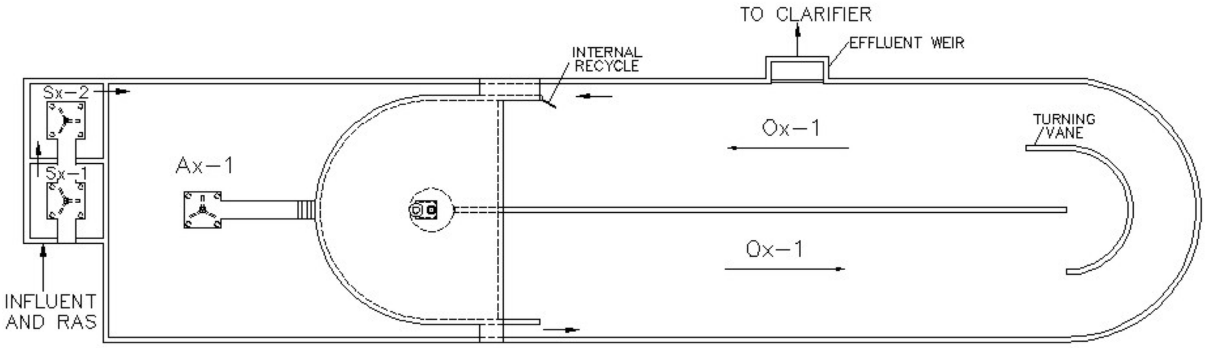
The first bio-selector is fed by the combination of influent and RAS. The fermentation of the mixed liquor allows for an anaerobic environment suitable for facilitating biological phosphorus release which is the first step in the luxury uptake process. The use of a selector zone not only facilitates phosphorus removal, but controls the F/M ratio at an elevated level encouraging the efficient growth of floc forming microorganisms, leading to a decreased SVI.

2. ANOXIC ZONE (AX-1, DE-NITRIFICATION STAGE)

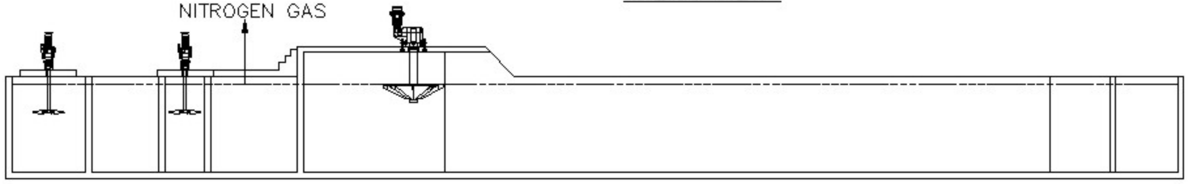
Following the Bio-Selectors, the anaerobic mixed liquor flows to the next zone where it is combined with the recycled nitrate rich mixed liquor from the oxic portion. The oxygen deficient, nitrate rich environment causes the microorganisms to rely on nitrate as an electron acceptor (i.e. de-nitrification). This process not only removes nitrogen, it also restores some of the alkalinity lost during nitrification in the oxic zone.

3. OXIC ZONE (OX-1, NITRIFICATION STAGE)

As the mixed liquor flows into the oxic zone, it combines with the oxygen rich mixture. The oxidation of BOD and ammonia occurs. The BOD is digested leaving increased cell mass and respired CO_2. The ammonia is oxidized to nitrate. “Luxury uptake” of phosphorus by microbes occurs as the phosphorous is stored as energy.



PLAN VIEW



ILLUSTRATIVE VIEW

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DESIGN DATA SHEETS

OxyStream^{TM}
DATA SHEET

Date: ___________________________ Approximate Plant Elevation: ________________ft
m
Plant: ___________________________ Water Temperature - Minimum
_______________^{0}C^{0}F
Location:_________________________ Water Temperature - Maximun
_______________^{0}C^{0}F
MLSS Concentration (mg/l)

____
Engineer:________________________ PH
____
Agent: __________________________
Alkalinity_____________________________________

PLEASE PROVIDE A COPY OF THE PLANT FLOW DIAGRAM

Plant Influent Characteristics

Municipal ☐ ______ % * If the majority of the influent is industrial waste, please provide TSS and VSS
*Industrial ☐ ______ % Nature of Industrial Waste:

Parameter	Unit of Measurement	Annual Average	Maximum Month	Maximum Day	Peak Hour	Permit Effluent Quality
Flow						
BOD_5						
Total COD						
TSS VSS						
TKN						
NH_4-N						
Total P						
Total N						

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The above values are based on ☐ primary effluent ☐ raw wastewater.

Mechanical Performances

Slow Speed Surface Aerators

Submersible ☐
Platform Mounted ☐
Other ☐

Mixers

Single Speed ☐
Two Speed ☐
VFD ☐

This is to help you determine whether or not the data provided by the client is in the range of typical values. If any of the following ratios are out if these ranges, the waste may be influenced by some industrial load or other circumstances and the data should be verified by the engineer.

The COD/BOD5/TKN/P ratio of DOMESTIC WASTEWATER is typically:
400/200/35/8

Typical Domestic WW Ratios	Raw Wastewater	Primary Effluent
COD/BOD$_5$	1.8-2.4	1.70-2.10
SBOD$_5$/BOD$_5$	0.3-0.4	0.45-.055
SCOD/COD	0.3-0.4	0.45-0.55
BOD$_5$/TKN	4.8-6.3	3.40-4.40
COD/TKN	9.0-14.0	6.00-10.00
BOD$_5$/TSS	0.9-1.1	1.60-1.80
TKN/NH$_4$-N	1.4-1.7	1.40-1.70

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BROCHURE

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WESTECH

ISO 9001
WESTECH
CERTIFIED
QUALITY SYSTEM

OxyStream™

Biological Nutrient Removal

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Sizing and Design

The OxyStream™ process combines the advantages of an oxidation ditch with the efficient, low maintenance Landy surface aerator. Our design software is based on a mathematical model that was developed from years of laboratory and plant operating data. The design is based on plant loadings, and required contaminant removal, as well as shock loads and storm flows. This allows us to maximize performance while minimizing capital and operating costs. Available layout variations provide for basin adaptability to most site constraints. Common wall construction further decreases capital costs.

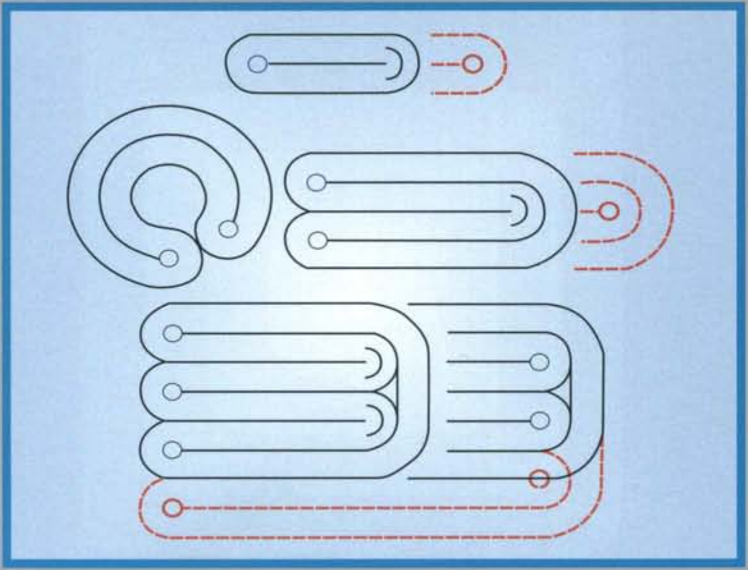
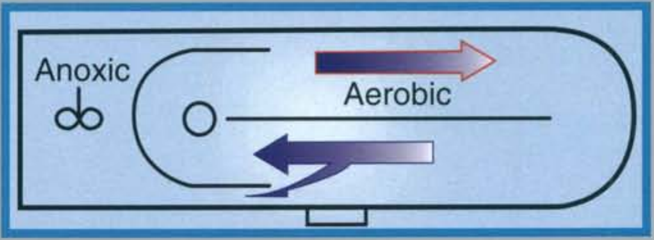


Illustration of common basin configurations. Operational parameters for each system are unique, and are designed based upon final site constraints.

Designs utilizing common wall construction offer additional capital cost savings.



The use of a by-pass channel and adjacent anoxic zone will allow effective de-nitrification without the use of recycle pumps.

Individual system design is specific to the requirements of each application. Our computerized model optimizes the basin geometry and location of aerators required to meet the process needs and discharge requirements. The computer model also identifies the optimum impeller size and speed to achieve proper wastewater treatment.

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Test Facility

Full scale testing measures:

- oxygen transfer
- power consumption and power current
- mechanical efficiency
- axial and radial forces
- vibration and noise level
- flow velocities

The Landy aerator is the heart of the OxyStream™ process. Our full scale 500,000 gallon capacity test facility is dedicated for the development and performance of Landy products. The test basin is equipped with an adjustable bridge and movable walls to accurately simulate job site conditions / geometry. Tests measure oxygen transfer and power consumption as well as torque, axial and radial forces on the impeller, and velocities. Our extensive testing program assures the owner a quality product that will perform efficiently for years to come.

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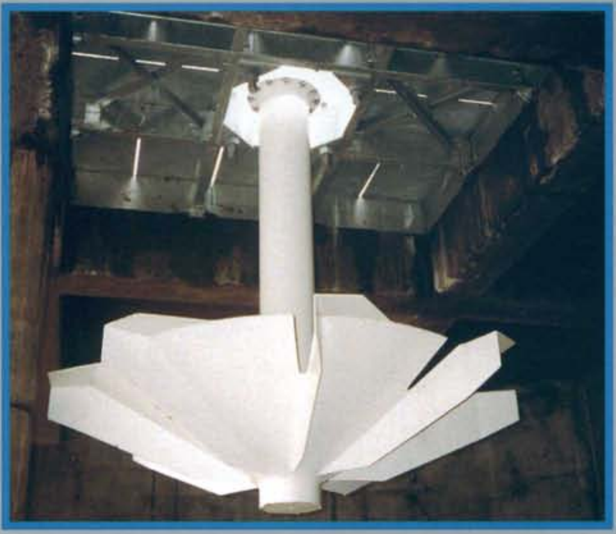
Landy Aerator



The Landy aerator is a low speed device that incorporates an open, non-clogging impeller. The unique impeller design eliminates rag build up that can result in unbalanced operation, a situation common with other impeller designs. Each aerator is fabricated in a specialized fixture and is balanced prior to shipment to assure years of trouble free operation. The Landy is generally mounted on a bridge or platform, but it can also be mounted on floats if desired.

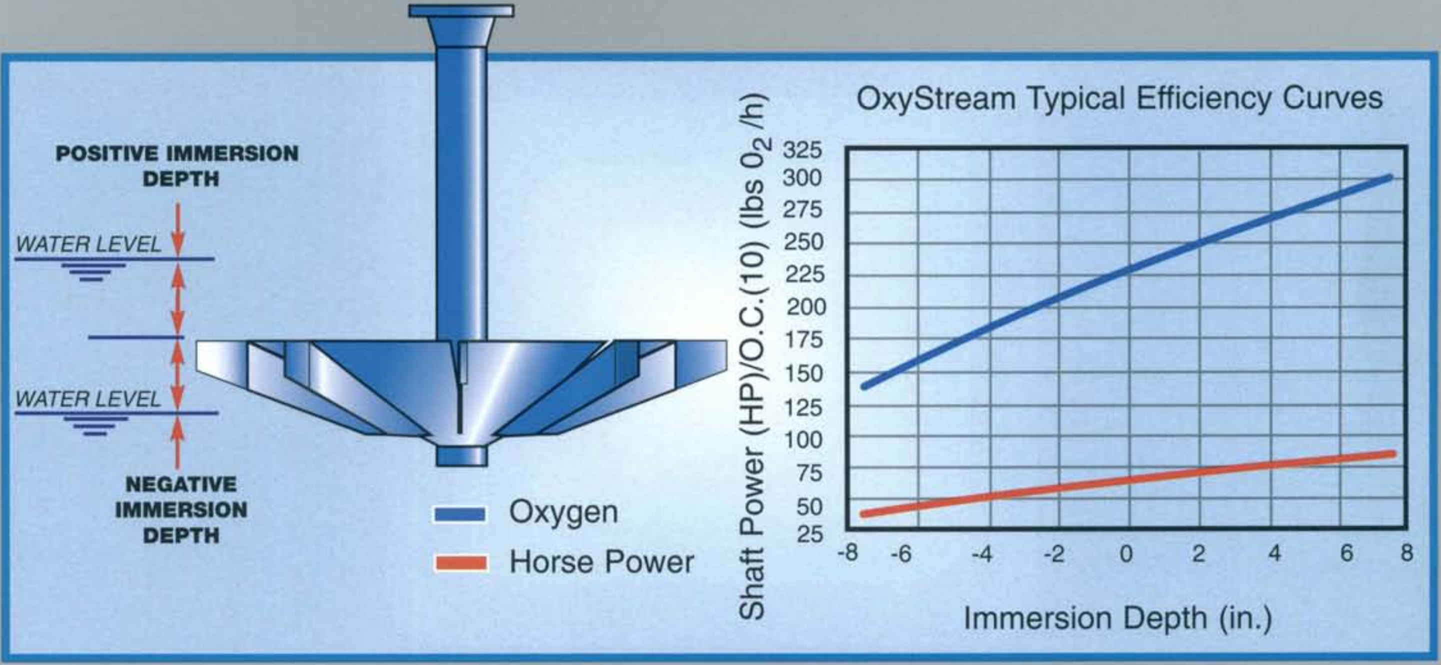
The Landy is available in sizes ranging from 2 ft. dia. to 13 ft. dia. The impeller can be fabricated in a variety of materials with coatings applied to meet the demands of your specific wastewater. The Landy is available as a complete unit or as a retrofit to mount onto an existing drive source.

The Landy aerator has been manufactured for over 40 years. Ongoing testing in both the field and testing facilities confirm that the Landy performs as designed. The Landy comes with operational and performance guarantees.

Currently the Landy aerator is being fabricated in North America under the direction of WesTech Engineering. WesTech is proud to oversee the manufacturing of this quality impeller under the exacting guidelines required to maintain ISO 9001 certification.

Advantages of Landy Aerators:

- Rugged and Reliable
- Non-clogging
- Energy Efficient
- Guaranteed Performance
- ISO 9001 Certified Supplier
- Stable Performance Over a Full Range of Immersion Depths



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Varied Applications

Landy Aerators are Currently Providing Aeration and Mixing in Numerous Applications Around the World.

- Circular and Rectangular Basins in Activated Sludge and Sludge Stabilization Applications
- Lagoons and Ponds
- Flow Equalization Basins and Buffer Tanks
- Floating in Variable Water Level Applications
- Providing Aeration, Mixing and Propulsion in Oxidation Ditches

The Landy aerator is a time proven workhorse. Landy aerators are operating in challenging industrial and municipal treatment plants around the world. The Landy is adaptable to every application - it can be mounted on a bridge or platform or secured to floats for use in lagoons, ponds, equalization basins, aerobic digesters...the list goes on. It is a versatile solution.

From the simplicity of an aerated facultative lagoon to the most stringent BNR application, the Landy is one of the most efficient and durable aeration products available.

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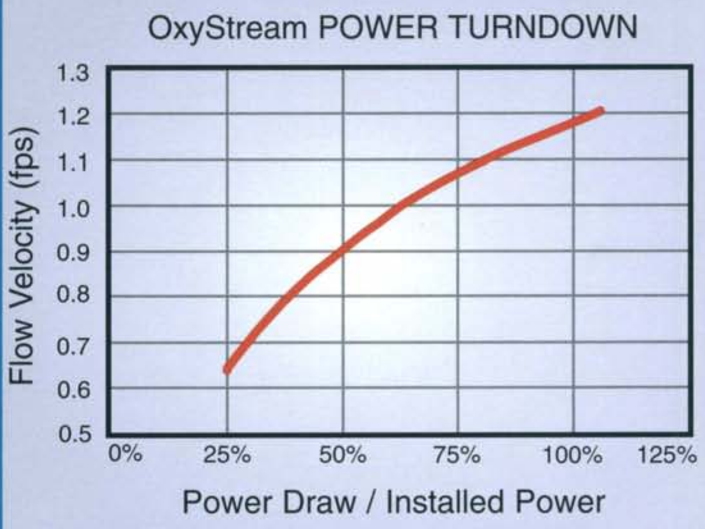
OxyStream™ Process Functions

Advantages of the OxyStream Process

- Single Source of Aeration and Mixing
- Simple Operation and Low Maintenance
- High Shock Load Resistance and Overall Capacity
- Advanced Filamentous Bulking Control
- Enhanced Simultaneous Nitrification-Denitrification
- Biological Phosphorus Removal
- No Design / License Fees



For a complete overview of WesTech products and services, visit us online at

www.westech-inc.com

WESTECH
an employee owned company

P.O. Box 65068 • Salt Lake City, Utah 84165-0068
Phone: (801) 265-1000 • www.westech-inc.com
e-mail: info@westech-inc.com

Represented by:

INSTALLATION LIST

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Job No.	Year	Location	Qty	Size	Equipment/Model
4799	1996	S. NAPA THAILAND BANGKOK TH	4		SURFACE AERATORS AES
4844	1996	POST FALLS WWTF POST FALLS ID	2		SURFACE AERATORS/OXYDIT AES2A2
4863	1996	MESQUITE WWTP MESQUITE NV	2	125 HP	SURFACE AER/OXYDITCH AES2A1
18014	1998	CEDAR CREEK WASTEWATER PL OLATHE KS	4	50 HP	SURFACE AERATORS AES2A2
18022	1999	SAANICH PENINSULA WWTP VICTORIA CN	4	75 HP	SURFACE AERATORS AES2B1
18180	1999	MAPLE LEAF FOODS BRANDON, MANITOBA CN	3	150 HP	SURFACE AERATORS AES1B2
5114	1999	BULLHEAD CITY WWTP BULLHEAD CITY AZ	2	100 HP	AERATORS AES2C3
18347	2000	LAURINBURG MAXTON WWTP MAXTON NC	2	50 HP	SURFACE AERATORS AES2A2
18251	2000	SPRING HILL WWTP SPRING HILL TN	4	50 HP	SURFACE AERATORS AES2B3
18353	2000	UMATILLA WWTP UMATILLA OR	2	75 HP	SURFACE AERATORS AES2B3
18389	2000	MADISONVILLE WWTP MADISONVILLE TX	2	15 HP	SURFACE AERATORS AES1A2
18425	2000	GALLATIN WWTP GALLATIN TN	2	25 HP	SURFACE AERATORS AES1A1
18165	2000	GARDEN CITY WWTP GARDEN CITY KS	4	150 HP	AERATORS AES2C3
18437	2000	LINDSAY WWTF LINDSAY CA	2	75 HP	SURFACE AERATORS AES2A2
18298	2000	ASHLEY VALLEY WWTF VERNAL UT	4	100 HP	SURFACE AERATORS AES2B3
18255	2000	AUGUSTA WWTF AUGUSTA KS	2	100 HP	SURFACE AERATORS AES2B2
18598	2001	DESTIN WWTP DESTIN FL	4	40 HP	SURFACE AERATORS AES2A2
18598	2001	DESTIN WWTP DESTIN FL	2	75 HP	SURFACE AERATORS AES2B2
18649	2001	GRANDVIEW WWTP GRANDVIEW WA	4	100 HP	SURFACE AERATORS AES2B3
18777	2002	DESTIN WWTP DESTIN FL	3	60 HP	OXYSTREAM AES2B3
18588	2002	EAST CANYON TREATMENT PLAN PARK CITY UT	4	100 HP	SURFACE AERATORS AES2C3
18835	2002	GALLATIN WWTP GALLATIN TN	3	25 HP	SURFACE AERATORS AES1A1

Job No.	Year	Location		Qty	Size	Equipment/Model
18826	2002	WICHITA STP # 3 WICHITA	KS	2	150 HP	OXYSTREAM AES2C3
18892	2002	BUTLER WWTP BUTLER	MO	2	50 HP	AERATORS AES2A3
18927	2002	CITY OF NIXA WWTP NIXA	MO	4	75 HP	AERATORS AES2C3
18915	2002	RIPON WWTF RIPON	WI	4	100 HP	SURFACE AERATORS AES2A3
18956	2002	UNION GROVE WWTP UNION GROVE	WI	2	75 HP	AERATORS AES2A3
19061	2003	KINGMAN WWTP KINGMAN	KS	1	50 HP	OXYSTREAM AES2B3
19118	2003	GALLATIN WWTP GALLATIN	TN	4	25 HP HP	AERATORS AES1A1
19056	2003	FOUR MILE CREEK WICHITA	KS	2	200 HP	AERATORS AES2C3
19103	2003	OTTAWA WWTP OTTAWA	KS	2	200 HP	AERATORS AES2C3
19124	2003	FRANKLIN WWTP FRANKLIN	TN	3	150 HP	AERATORS AES2B3
19136	2004	MOUNTAIN VIEW WWTP MOUNTAIN VIEW	MO	1	50 HP	OXYSTREAM AES2C3
19163	2004	GEN POWER DUNKARD TOWNSHIP	PA	3		AERATORS AES0X0
19321	2004	WEST PALM BEACH WEST PALM BEACH	FL	4	100 HP HP	AERATORS AESXD1
19262	2004	MARCH AIR RESERVE WRRP RIVERSIDE	CA	2		SURFACE AERATORS AES2A3
19362	2004	PATTERSON PASS WWTP PATTERSON	CA	2	100 HP HP	SURFACE AERATORS AES2B3
19315	2004	LIVINGSTON PARICH SEWER DIS	LA	2	50 HP HP	AERATORS AES2A1
19486	2005	HEFEI	CI	6	200 HP HP	AERATORS & CONTROL SYSTE AES2C3
19377	2005	PISMO BEACH PISMO BEACH	CA	4	60HP HP	AERATORS AES2B3
19512	2005	SOUTH HOPKINS WWTP NORTONVILLE	KY	2	60 HP HP	OXYSTREAM AES2B3
19477	2005	YIN CHUAN	CI	8	160 KW KW	AERATORS & CONTROL SYSTE AES2C3
19426	2005	OLIVEHURST WWTP OLIVEHURST	CA	4	150 HP HP	AERATORS AES2B3
19622	2005	OSTEGO OTSEGO	MN	1		OXYSTREAM AES2C3

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CASE STUDIES

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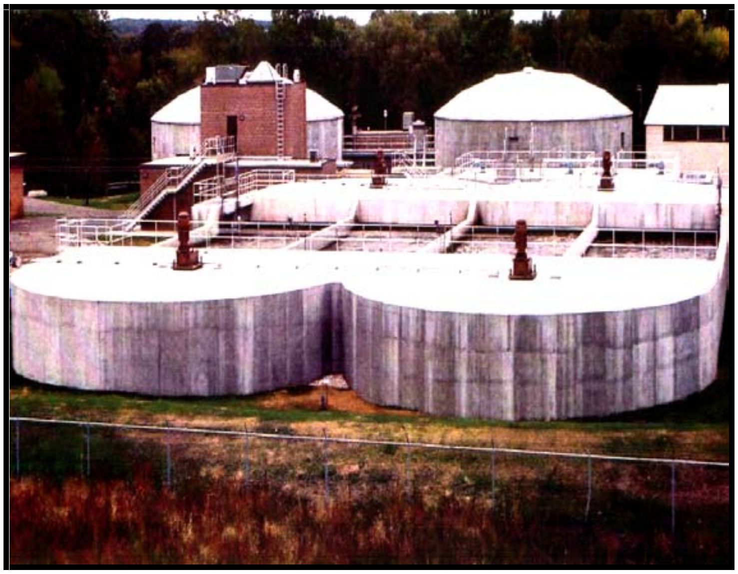
Plant Case Study

Ripon, WI WWTP

WesTech

WESTECH EQUIPMENT:
(2) OxyStream^{TM} Systems
(4) 100 HP Surface Aerators
(2) 70' Dia. Secondary Clarifiers



LOCATION: RIPON, WI

ENGINEER: EARTH TECH
SHEBOYGAN, WI

INSTALLED: 2002
JOB NO: 18915

CONTACT: PHIL HOOPMAN
PLANT DIRECTOR

PHONE: (920)748-4912

Plant Performance Data - Monthly Average

2003-4	Flow	Influent (mg/l)				Effluent (mg/l)				
Month	MGD	BOD$_5$	TSS	NH3*	TP	BOD$_5$	TSS	NH3	NO3	TP
July	1.33	285	301	29		< 2.0	4.9	0.1	4.9	0.2
Aug	1.30	351	204	29		< 2.0	5.4	0.1	4.4	0.6
Sept	1.23	389	214	29	5.5	< 2.0	6.5	0.1	4.0	0.7
Oct	1.23	368	183	29	5.5	< 2.0	4.2	0.1	3.6	0.6
Nov	1.37	289	179	29	4.6	< 2.0	7.1	0.1	3.9	0.6
Dec	1.43	323	175	29	4.9	< 2.0	5.2	1.3	1.3	0.3
Jan	1.48	338	168	29	4.9	< 2.0	3.6	0.3	1.5	0.3
Feb	1.55	407	185	29	5.2	3.4	4.3	0.2	1.9	0.2
March	1.49	278	160	29	4.1	3.8	5.8	0.3	1.6	0.2
April	1.31	291	149	29	4.7	3.2	7.3	0.1	2.0	0.3
May	2.32	290	134	29	3.5	5.4	10.4	0.1	1.8	0.3
June	3.82	163	95	29	2.1	1.3	2.9	0.1	1.5	0.2

* Ammonia is not sampled routinely; these values are based on limited data.

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Plant Case Study

Mesquite WWTP

WESTECH

As Public Works Director at the City of Mesquite, NV, Bill Tanner has enjoyed the superior treatment performance and problem-free operation of the OxyStream^{TM} Biological Treatment Process from WesTech Engineering.

"We are pleased with our WesTech Equipment," reports Tanner.

The Mesquite WWTP consists of three (3) influent screw pumps, a 1/4" fine screen, a WesTech vortex grit chamber with a WesTech Gritt Mitt^{TM} classifier, the WesTech OxyStream^{TM} System with two (2) 125 HP surface aerators, two (2) 70' WesTech secondary COP^{TM} clarifiers, and chlorine disinfection. Currently, Mesquite employs a water reuse program for their high quality effluent with a local golf course.

As seen in the table below, the Mesquite OxyStream^{TM} consistently achieves complete nitrification and de-nitrification. This treatment system includes several design features to allow for this advanced level of nutrient removal. These features include dual surface aerators, an adjustable effluent weir and submerged mixer blades.

Turning an aerator off and/or varying the impeller submergence with the effluent weir provides control of the oxygen transfer. Regulating this oxygen transfer allows the plant to create anoxic zones for the removal of nitrate. Accordingly, the total volume of the basin was increased to permit complete, simultaneous de-nitrification. In addition, supplemental mixers were installed for increased flexibility and maximum turndown of the system. WesTech worked with Stantec Engineering (formally EWP) and Ellsworth Paulson on the design, installation, and start-up of this successful installation.

Please contact Bill Tanner at the City of Mesquite, Nevada for further information.
702-346-5237

Plant Performance Data – Monthly Average

2002	Flow	Influent (mg/l)		Effluent (mg/l)		
Month	MGD	BOD_5	TKN	BOD_5	NH4	NO3
Jan	1.26	241	50.6	3	1.01	0.31
Feb	1.33	214	39.8	3	0.68	0.28
March	1.32	169	46.5	2	0.08	2.45
April	1.47	201	38.7	7	1.37	1.71
May	1.52	189	34.7	3	1.03	0.14
June	1.47	225	46.3	3	0.45	0.13
July	1.69	220	31.6	3	0.11	1.36
Aug	1.46	238	34.7	2	0.16	1.68
Sept	1.54	214	43.1	2	0.24	0.20
Oct	1.66	286	30.8	2	0.11	0.29
Nov	1.57	208	33.5	2	0.12	0.68
Dec	1.65	115	34.0	2	1.26	0.71

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Plant Case Study

Garden City WWTP

WESTECH

WESTECH EQUIPMENT:
(2) OxyStream^{TM} Systems w/
 (4) 150 HP Surface Aerators
 (2) Flow Gates
 (4) 10 HP Anoxic Zone Mixers
 (2) 5 HP Anaerobic Zone Mixers
(3) 75' Dia. COP^{TM} Secondary Clarifiers w/
 Sludge Rings

LOCATION:	GARDEN CITY, KS
ENGINEER:	MID-KANSAS ENG. CONSULTANTS, INC. WICHITA, KS
INSTALLED:	DECEMBER 2001
JOB NO:	18165
CONTACT:	MARK EISENBARTH CHIEF OPERATOR
PHONE:	(620)276-1280

Plant Performance Data - Monthly Average

2003	Flow	Influent (mg/l)				Effluent (mg/l)				
Month	MGD	BOD$_5$	TSS	NH3	TP	BOD$_5$	TSS	NH3	NO3	TP
Jan	3.18	246	176	30.8	5.9	2.0	5.1	0.16	1.8	2.54
Feb	3.31	260	211	20.0	3.6	2.3	1.9	0.11	3.6	1.94
Mar	3.20	221	200	26.4	4.4	8.6	3.6	2.62	0.7	1.38
April	3.63	213	200	16.1	4.6	3.8	2.2	0.57	0.8	0.49
May	3.35	221	188	17.5	6.7	4.0	3.2	0.11	0.1	2.54
June	3.39	229	226	22.2	5.2	5.7	8.6	0.54	1.1	1.51
July	3.66	200	200	21.6	4.6	2.2	2.6	0.16	9.0	2.41
Aug	3.70	186	533	40.0	6.8	2.4	3.2	0.12	1.1	1.33
Sept	3.50	263	533	28.3	2.3	3.9	3.2	0.13	7.9	1.09
Oct	3.16	213	175		5.1	1.7	0.7	0.21	2.7	1.61
Nov	3.24	192	175	31.0	4.0	3.3	2.1	0.13	3.6	1.69
Dec	3.23	230	200			4.1	1.8	0.00	6.7	0.77
AVG	3.38	223	252	25.4	4.8	3.7	3.2	0.41	3.2	1.61

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Plant Case Study

Destin Water Users

WESTECH

WESTECH EQUIPMENT:

(5) OxyStream^{TM} Systems
(4) 40/30 HP Surface Aerators
(2) 75/56 HP Surface Aerators
(3) 60 HP Surface Aerators
(1) Flow Control Gate
(1) Adjustable Effluent Weir
(2) 56’ Dia. COP^{TM} Secondary Clarifiers

LOCATION: DESTIN, FL

ENGINEER: BASKERVILLE-DONOVAN
PENSACOLA, FL

INSTALLED: 2000, 2002
JOB NO: 18598, 18777

CONTACT: DARREN ALFORD
CHIEF OPERATOR
PHONE: 850-837-6551

Plant Performance Data - Monthly Average

2002	Flow	Influent (mg/l)		Effluent (mg/l)	
Month	MGD	BOD_5	TSS	BOD_5	TSS
Jan	1.74	200	275	1.8	0.8
Feb	1.85	222	280	2.2	2.4
Mar	2.33	212	229	3.1	2.3
April	2.49	217	285	3.4	5.7
May	2.67	250	312	3.0	3.0
June	3.45	330	449	3.7	5.0
July	3.82	286	482	3.4	3.3
Aug	3.34	273	438	3.3	2.5
Sept	3.18	231	345	2.1	4.9
Oct	2.84	205	260	1.6	3.6
Nov	2.01	297	447	1.2	1.7
Dec	1.70	299	472	0.6	3.1

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WEF PUBLICATION

ADVANCED OXIDATION DITCH DESIGN MEETS STRICT EFFLUENT REQUIREMENTS

Nathan Cassity, P.E., Steve Arant, P.E., DEE
Earth Tech, Inc.
4135 Technology Parkway
Sheboygan, WI 53083

ABSTRACT

The Ripon, Wisconsin wastewater treatment facilities needed upgrading to comply with new effluent requirements for BOD and TSS, and to provide reliable nitrification. An oxidation ditch system was selected from the several process alternatives evaluated based on ease of operation and capital costs. The proposed oxidation ditch system included separate basins for biological phosphorus removal, automatic dissolved oxygen control system utilizing oxidation-reduction potential (ORP) probes, and deep final clarifiers with energy dissipating inlets. ORP monitoring and set points were used to control the speed of the aerators for matching oxygen demand. These same probes were used to identify periods of high organic loadings and automatically control urea feed rate.

The oxidation ditch system was started up in May 2003 and has been reliably achieving the stringent effluent requirements, as well as producing an effluent low in total nitrogen. The oxidation ditch process provides for automatic control of dissolved oxygen, denitrification, supplemental nitrogen feed, and improved biological phosphorus removal.

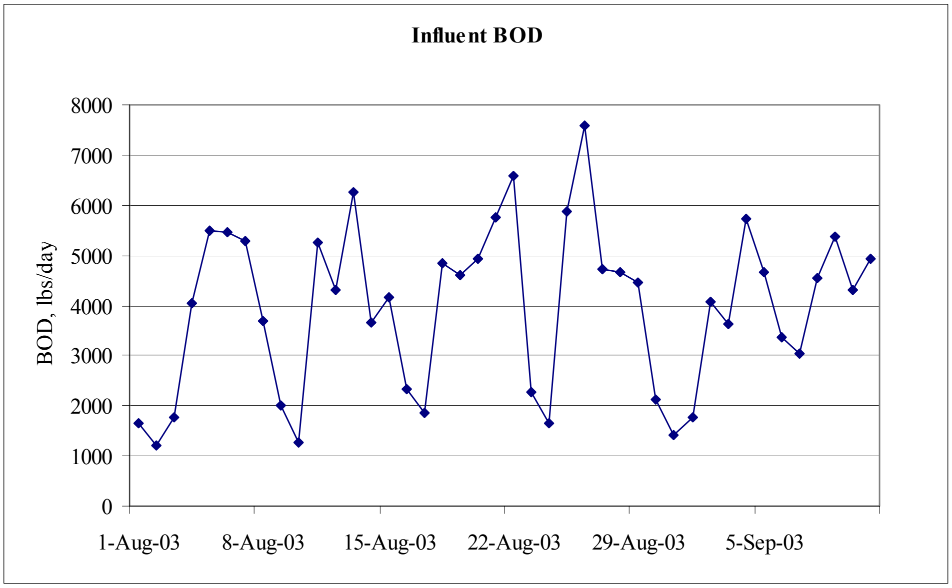
KEYWORDS

Oxidation ditch, aeration control, nutrient limitation, oxidation-reduction potential probes, supplemental nutrient addition, industrial loadings

BACKGROUND

The City of Ripon, Wisconsin, enjoys a strong industrial base, consisting primarily of food processing facilities. Food processing industries including Rippin Good Cookies and Smuckers contribute over 75% of the organic loadings to the municipal treatment plant. These industrial discharges are quite variable and regularly produce nutrient deficient conditions in the activated sludge treatment system. Figure 1 displays a graph of influent BOD values demonstrating the high variability in loadings.

Figure 1 – Ripon WWTF Influent BOD Values Displaying High Variability



The Ripon Wastewater Treatment Facility (WWTF) has an existing annual average flow of 1.4 MGD with a year 2020 design flow of 1.8 MGD. The old WWTF included a pair of compact plants for the activated sludge system that were unable to reliably achieve required ammonia removal. The old system did not provide stable operation especially during periods of nitrogen deficiency. Discharge is into an effluent dominated stream and the new discharge permit has some of the most stringent effluent limits in the state of Wisconsin, further challenging the existing wastewater treatment facility. The existing wastewater treatment facilities needed upgrading to comply with the new requirements for BOD and TSS, and to provide reliable nitrification. Table 1 displays the facility's effluent limits.

Table 1 – Ripon WWTF Effluent Limits

Pollutant	Weekly Average Limit	Monthly Average Limit
BOD	6 mg/L	--
TSS	10 mg/L	--
Ammonia (May – Oct.)	0.7 mg/L	--
Ammonia (Nov. – April)	3.1 mg/L	--
Total Phosphorus	--	1.0 mg/L

The primary goal of this project was to provide a stable treatment process that would handle the highly variable loading conditions, while protecting the receiving stream. The receiving stream, Silver Creek, flows into Big Green Lake. Both of these water bodies represent significant fisheries for southern Wisconsin.

IDENTIFYING THE PROBLEM

The existing treatment facilities were unable to reliably achieve low effluent ammonia levels. In addition, the treatment facility suffered from activated sludge bulking and foaming. The existing treatment facilities were evaluated, together with review of nutrient requirements, effluent total nitrogen levels, and microscopic evaluation of the activated sludge. The existing activated sludge system was too small to provide adequate solids retention time for nitrification, in particular during the cold Wisconsin winters. Erratic low effluent ammonia levels achieved in the existing system were a result of nitrogen limiting conditions. Microscopic evaluation identified the presence of *Nostocoida limicola* and *Thiothrix* (generally associated with nutrient deficiency), *Sphaerotilus natans* (generally associated with low dissolved oxygen), and *Type 021N* and *Nocardia* (generally associated with variable industrial loading). The occurrence of exocellular lipopolysaccharide (slime), which contributed to bulking, also demonstrated nutrient deficient conditions were present. Grab samples on the effluent confirmed nitrogen limitations were present in the activated sludge process.

Highly variable organic loading patterns presented a challenge for upgrading the wastewater treatment facilities. Influent BOD varies by over 400 percent from day-to-day. During periods of high organic loading, nitrogen limited conditions exist. During periods of low organic loading, excess nitrogen is available; however, a viable mass of nitrifiers must be present to remove this available ammonia. A control system was required that could identify nutrient limited conditions and feed sufficient nitrogen to the process to satisfy the nutrient needs of the heterotrophic bacteria, and also provide adequate excess ammonia to maintain a viable nitrifier mass during peak loading conditions. In this way, nitrifiers would be available during periods of low organic loading to remove excess ammonia present in the influent.

THE SOLUTION

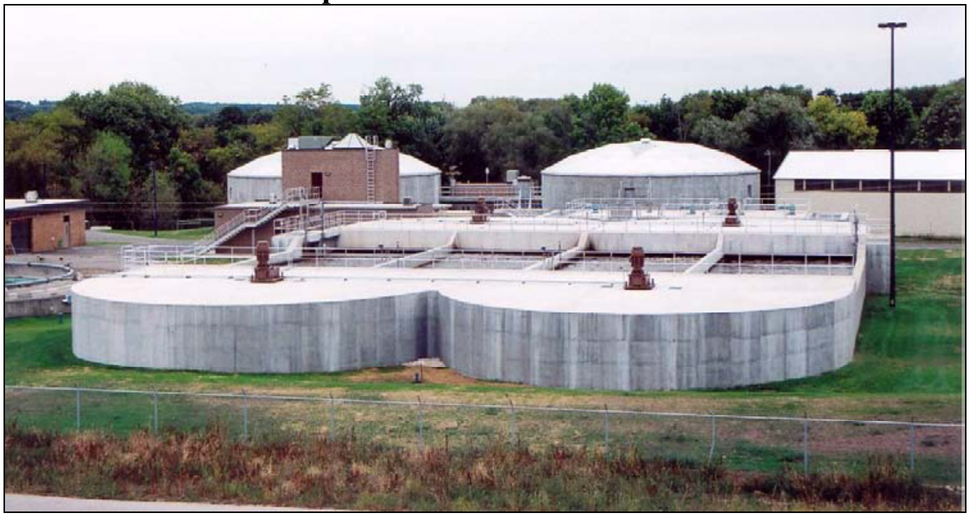
An oxidation ditch system was selected from the several process alternatives evaluated based on ease of operation and capital costs. The proposed oxidation ditch system included separate basins for biological phosphorus removal (BPR), an automatic dissolved oxygen control system utilizing oxidation-reduction potential (ORP) probes, and deep final clarifiers with energy dissipating inlets. ORP monitoring and set points were used to control the speed of the aerators for matching oxygen demand. These same probes were used to identify periods of high organic loadings and automatically control the urea feed rate. As the speed of the aerators increase due to high industrial loadings, the speed set point triggers the urea feed. ORP probes are easy to maintain and can accurately measure low dissolved oxygen levels. In addition, the ORP readings can be used as a surrogate measurement of nitrate concentration, and allow denitrification to occur within the oxidation ditch system, further improving the performance of the BPR process and providing a denitrified effluent.

The oxidation ditch system was started up in May 2003 and has been reliably achieving the stringent effluent requirements, as well as producing an effluent low in total nitrogen. The oxidation ditch process provides for automatic control of dissolved oxygen, denitrification, supplemental nitrogen feed, and improved biological phosphorus removal, with minimal operator interface. The backup chemical phosphorus removal system has not been needed.

OXIDATION DITCH PROCESS OVERVIEW

The oxidation ditch process is a completely mixed activated sludge process with aeration typically accomplished by mechanical aerators. The tankage at the Ripon facility consists of an oval “racetrack”, which describes how the flow in the tanks races around a track-shaped flow path. Biological nitrogen removal is accomplished within the oxidation ditch, while biological phosphorus removal is accomplished utilizing selector basins directly upstream of the ditch. Figure 2 displays an overview picture of the Ripon WWTF oxidation ditches.

Figure 2 – Overview Picture of Ripon Oxidation Ditches

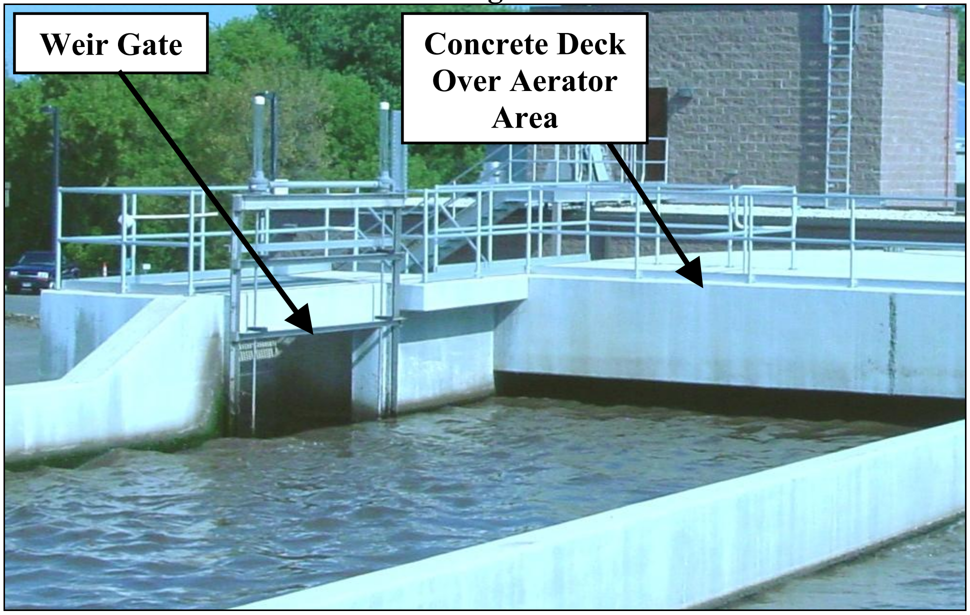


There are several advantages to the oxidation ditch process. There is no need for a blower building due to the use of mechanical aeration. The extended aeration process utilized provides a stable, reliable, and operator friendly process due to relatively long SRT and low solids production. Also, the completely mixed system handles highly variable loading patterns better than a plug flow system.

A few additional advantages that the Ripon operations staff realized were an energy consumption reduction of 16 percent, sewerage rates that are 25 percent below the Wisconsin state average, and elimination of the need for industries to pretreat their discharges, which would have driven a few industries out of the city.

The Ripon facility includes two oxidation ditches with a volume of one million gallons each and side water depths of 14 feet. Four 100 horsepower adjustable speed aerators provide mechanical aeration. The vertical shaft aerators have 10 ft - 6 in. diameter impellers. Weir gates 10 feet wide on each oxidation ditch control the water level, which controls the submergence of the aerators and the aeration energy transferred to the water. Concrete decks cover the area over the aerators to minimize heat loss. The decks have concrete skirt walls, which decrease the opening between the water surface and the deck to approximately 18 inches. Figure 3 displays the weir gate and concrete deck with skirt wall on one of the oxidation ditches.

Figure 3 – Weir Gate and Concrete Deck Design Details



The automated operation strategy for the oxidation ditch aerators uses ORP probes for dissolved oxygen (DO) monitoring and control instead of DO probes. There is one ORP probe in each oxidation ditch located upstream of the second aerator. The ORP set point maintains a DO concentration in the mixed liquor directly out of the aerators slightly above 1 mg/L with a decreasing gradient to approximately 0.3 mg/L just before the mixed liquor reaches the next aerator.

PHOSPHORUS REMOVAL

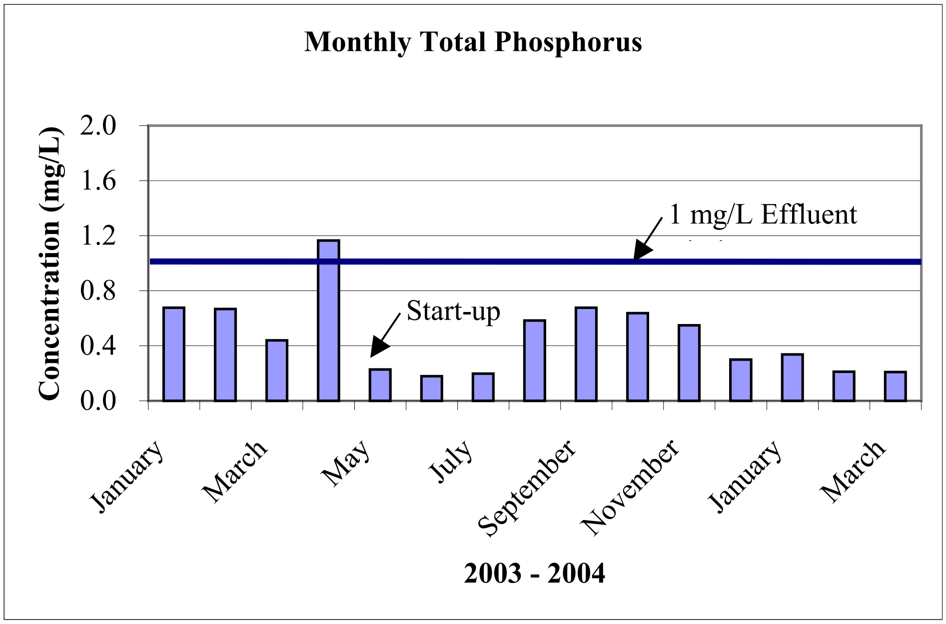
Biological phosphorus removal is accomplished utilizing anaerobic selector basins (mixing basins) directly upstream of the oxidation ditches. The mixing basins consist of three basins in series. Each mixing basin has a volume of 77,600 gallons with an 18 ft. side water depth. The piping layout allows raw wastewater and return activated sludge (RAS) to be fed to any of the three basins. This feature allows the option of running the system with separate RAS denitrification before combining the RAS with the raw wastewater. The layout also allows any of the three basins to be taken off-line separately. Vertical shaft mixers supported on partial concrete decks provide mixing energy to the basins.

The anaerobic environment provided by the mixing basins is used to select for phosphorus storing bacteria (Bio-P bacteria). Since Bio-P bacteria cycle several times through the anaerobic and aerobic environments of the activated sludge system before being wasted, they are conditioned to store excess phosphorus in high-energy compounds in the aerobic stage for utilization in the anaerobic stage. As the activated sludge passes through the mixing basins, the bacteria have no oxygen for respiration and must switch to anaerobic respiration to derive energy. In contrast to the typical bacteria present in activated sludge, Bio-P bacteria can uptake food in an anaerobic environment by utilizing stored, high-energy phosphorus compounds. The result is that Bio-P bacteria are fed in the anaerobic environment thereby having a competitive advantage over other bacteria. Adequate readily biodegradable BOD must be provided to the

Bio-P bacteria in the anaerobic environment for food in order for the biological phosphorus removal process to succeed.

Figure 4 displays monthly average effluent total phosphorus results after startup of the new facility in May 2003. As can be seen in the figure, effluent total phosphorus is regularly below 0.4 mg-P/L without any need for chemical polishing. The facility has a few advantages for biological phosphorus removal including relatively high concentrations of readily biodegradable BOD in the influent from the food processing industries and low nitrate concentrations returned in the RAS due to the nitrogen removal achieved in the oxidation ditches.

Figure 4 – Ripon WWTF Effluent Total Phosphorus Performance

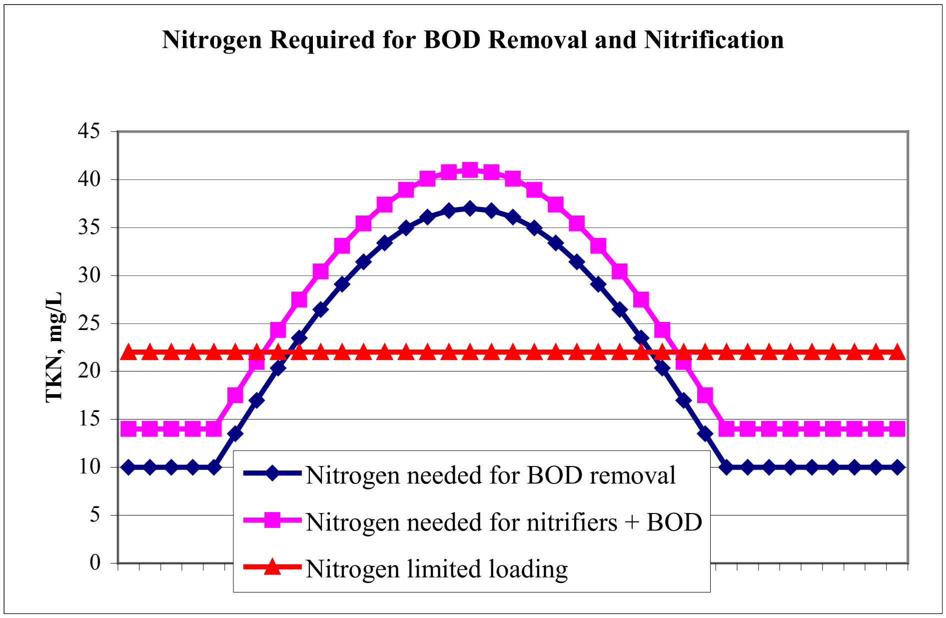


AMMONIA REMOVAL

Like any other extended air activated sludge process, ammonia removal is accomplished by operating at a relatively long SRT. The design SRT for the oxidation ditches is 15 days. The difficulty present with the facility's nitrification process is nitrogen-limiting conditions experienced, which can starve nitrifiers out of the system. A sufficient population of nitrifiers must be maintained in the system at all times in order to nitrify the ammonia present when nutrient deficient conditions end and a more typical ammonia loading enters the facility. If an adequate population of nitrifiers cannot be maintained in the system, ammonia will bleed through the process causing high ammonia concentrations in the discharge. This was a common occurrence with the old facility and was remedied in the new process by providing supplemental nutrient addition in the form of a urea feed system.

Figure 5 displays a graph depicting a simplified relationship between nitrogen demands for a period of time when a large BOD loading enters the activated sludge process and then resumes to a lower loading. The required nitrogen for BOD removal increases as the BOD loading to the system increases. In order to maintain a population of nitrifiers in the system, an excess amount of nitrogen must be present above that required for BOD removal. A nitrogen-limited condition occurs when the nitrogen loading to the process is lower than that required for BOD removal and sustaining nitrifiers.

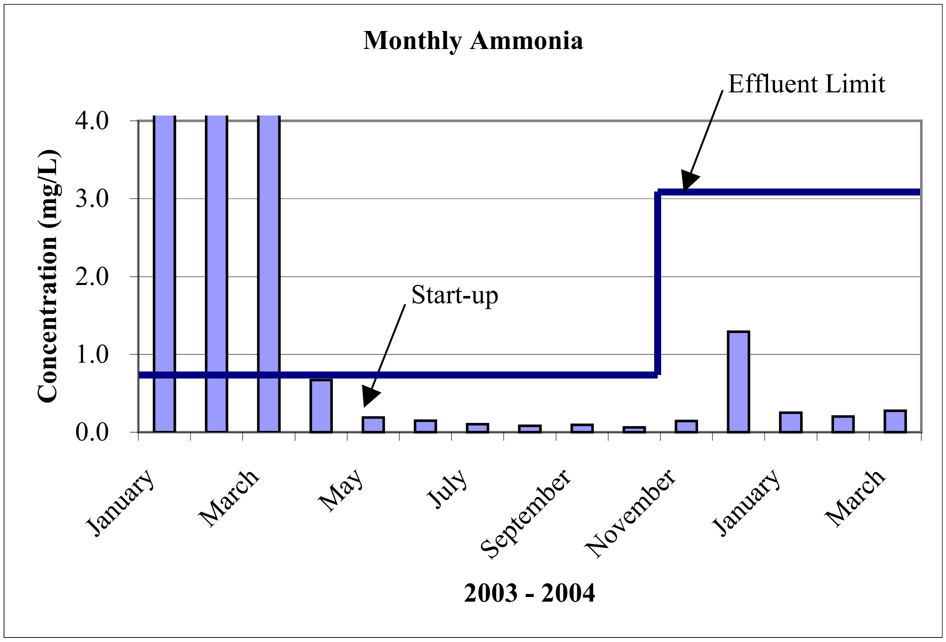
Figure 5 – Required Nitrogen for BOD Removal and Nitrification



The urea feed system provides automated supplemental ammonia addition during periods of high BOD loading to the facility. The automatic control system paces the urea feed pumps based on the mechanical aerator speed, which increases and decreases to meet oxygen demand to the oxidation ditches. When a high BOD loading enters the oxidation ditches, the mechanical aerators speed up to meet the increased oxygen demand. The urea feed pumps will then increase flow proportional to maximum and minimum aerator speed set points and deliver the required amount of nitrogen to the system to accomplish BOD removal and sustain a nitrifier population. If the aerator speed falls below a minimum set point, the urea pumps will shut off since supplemental nitrogen is not needed at periods of low loadings.

The ammonia removal performance of the facility is displayed in Figure 6. Prior to startup of the new facility in May 2003, effluent ammonia concentrations exceeded the effluent limitation due to the inability to maintain a sufficient nitrifier population in the old system. The new facility consistently maintains effluent ammonia concentrations between 0.1 and 0.3 mg-N/L.

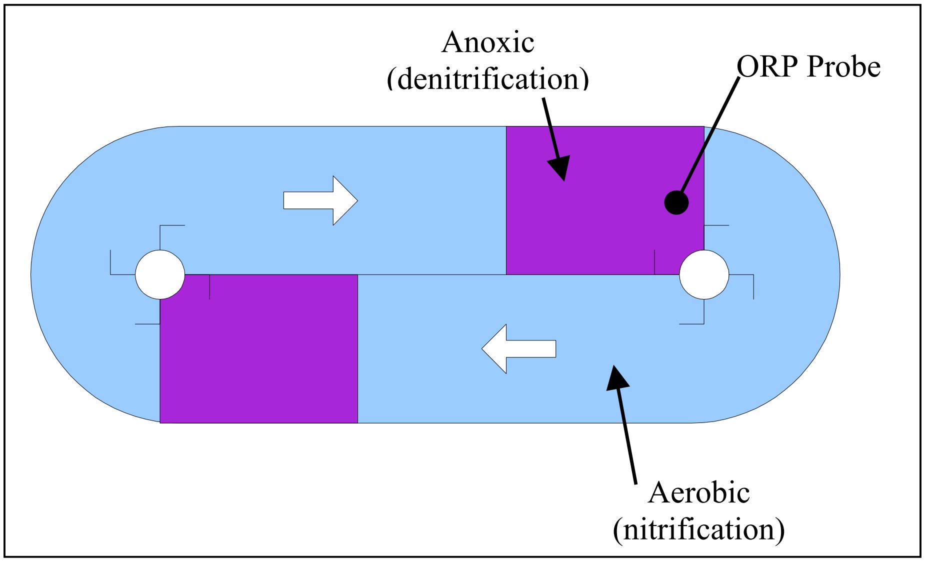
Figure 6 – Ripon WWTF Effluent Ammonia Performance



NITRATE REMOVAL

The nitrate removal process makes up a large part of the aeration control strategy for the oxidation ditches. Nitrate is removed by establishing areas of low dissolved oxygen (anoxic zones) in the oxidation ditches where denitrification occurs. Figure 7 displays a conceptual diagram of the anoxic zones at the locations upstream of the aerators. ORP probes are used to monitor and control DO concentrations in the oxidation ditches instead of DO probes because the concentration at the probe locations must be controlled accurately at low concentrations in order to accomplish denitrification.

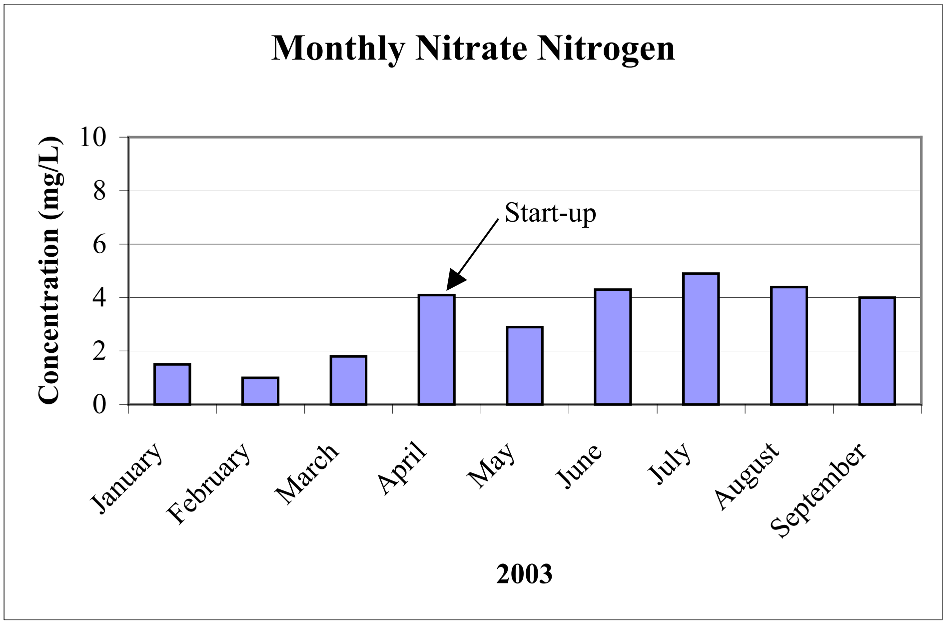
Figure 7 – Conceptual Diagram of Oxidation Ditch Nitrogen Removal



ORP probes allow the activated sludge system to remove nitrate and they have several advantages in this application. Compared to DO probes, ORP probes require less frequent cleaning and calibration. ORP probe readings in an aerobic environment are proportional to DO concentration and can accurately measure DO concentration down to zero, whereas DO probes become inaccurate below approximately 0.5 mg/L. After DO concentration falls to zero, ORP readings are proportional to nitrate concentration, which provides an indication of denitrification or anoxic conditions. The ability to measure oxidizing potential and define both aerobic and anoxic conditions allows the automated aeration control system to be operated at the conditions needed to achieve nitrate removal in the system.

The effluent nitrate results displayed in Figure 8 show a few different characteristics of the old and new facility. The balance between nitrogen addition for nutrient deficiency and nitrogen removal for effluent quality creates an optimum window of effluent nitrate concentrations between 2 and 4 mg-N/L that the facility aims to maintain. A nitrate concentration below 2 mg-N/L can indicate a nutrient deficiency, while a nitrate concentration above 4 mg-N/L can indicate decreased denitrification performance in the oxidation ditches and overfeeding of supplemental nitrogen. As shown in Figure 8, previous to startup of the new facility effluent nitrate concentration was routinely below 2 mg/L indicating a lack of nitrifiers in the system and nutrient difficiency. After startup of the new facility, effluent nitrate averaged 4 mg-N/L indicating sufficient nitrogen was being fed to establish a population of nitrifiers in the system and denitrification was occurring keeping nitrate concentrations low in the effluent.

Figure 8 - Ripon WWTF Effluent Nitrate Performance

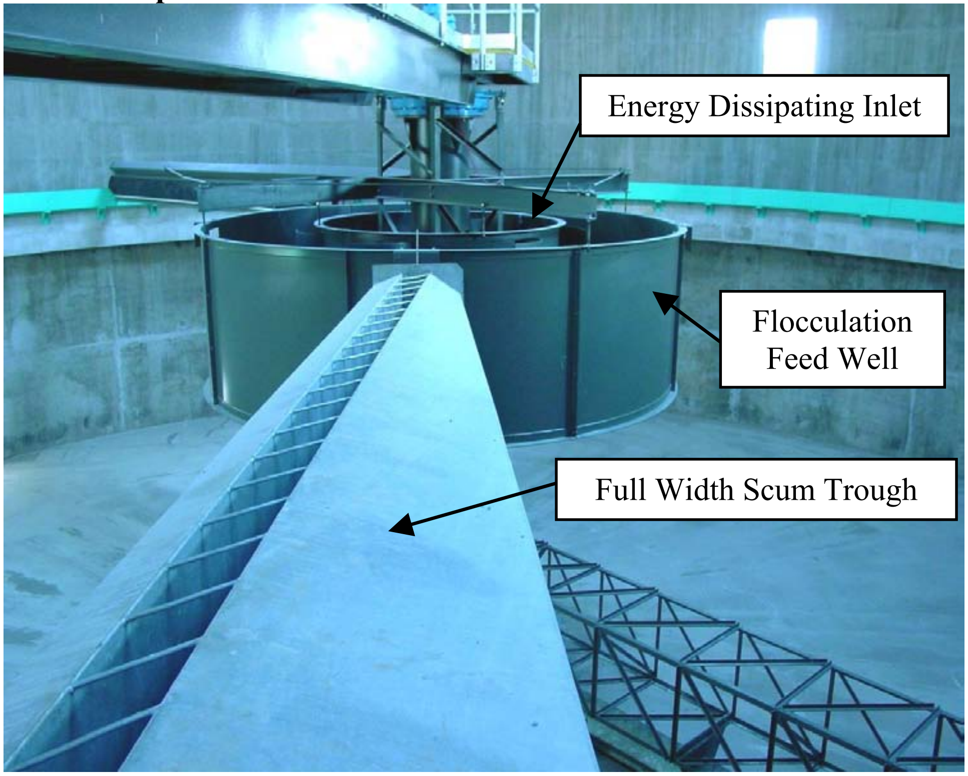


HIGH PERFORMANCE CLARIFIERS

The two 70-ft diameter secondary clarifiers have several design features that improve clarification, reduce heat loss, and improve sludge pumping. First, the clarifiers have geodesic dome covers, which improve clarification by eliminating wind effects that can cause surface currents and transport solids quickly across the clarifiers to the weirs, and reduces thermal gradients that can cause instability in the water column. The covers also minimize heat loss in the winter months, consequently maintaining the RAS temperature and improving nitrification performance in the activated sludge system. Since there are no wind effects to transport scum to the periphery of the clarifier (the location where most scum troughs are located), a full-length scum trough removes scum from the entire radius of the clarifiers. The full-length scum trough is labeled on the interior clarifier picture in Figure 9.

Second, the clarifiers have 15 ft side water depths that provide improved operator flexibility in controlling sludge blanket depths and greater sludge storage capacity during periods of poor settleability. Third, the energy-dissipating inlet and flocculation feed well design reduce floc shear and promote flocculation at the inlet of the clarifier. The energy dissipating inlet and flocculation feed well are labeled in Figure 9. Fourth, the suction sludge header, which has been a common feature on secondary clarifiers for several years, provides rapid sludge removal and reduces the sludge detention time in the clarifiers. This feature is especially important for facilities with biological phosphorus removal in order to avoid anaerobic conditions that may cause unwanted phosphorus release.

Figure 9 – Interior Ripon WWTF Clarifier Picture



BOD AND TSS REMOVAL PERFORMANCE

Figures 10 and 11 display the effluent BOD and TSS performance of the new facilities after startup in May 2003. The BOD results include several months with BOD concentrations below the detection limit and TSS concentrations averaging 5 mg/L. The BOD and TSS performance prior to startup was achieved with tertiary filtration on-line. Prior to startup of the new oxidation ditch and clarifier facilities, the tertiary filters were taken off-line; therefore, results were achieved using only secondary clarification.

Figure 10 – Ripon WWTF Effluent BOD Performance

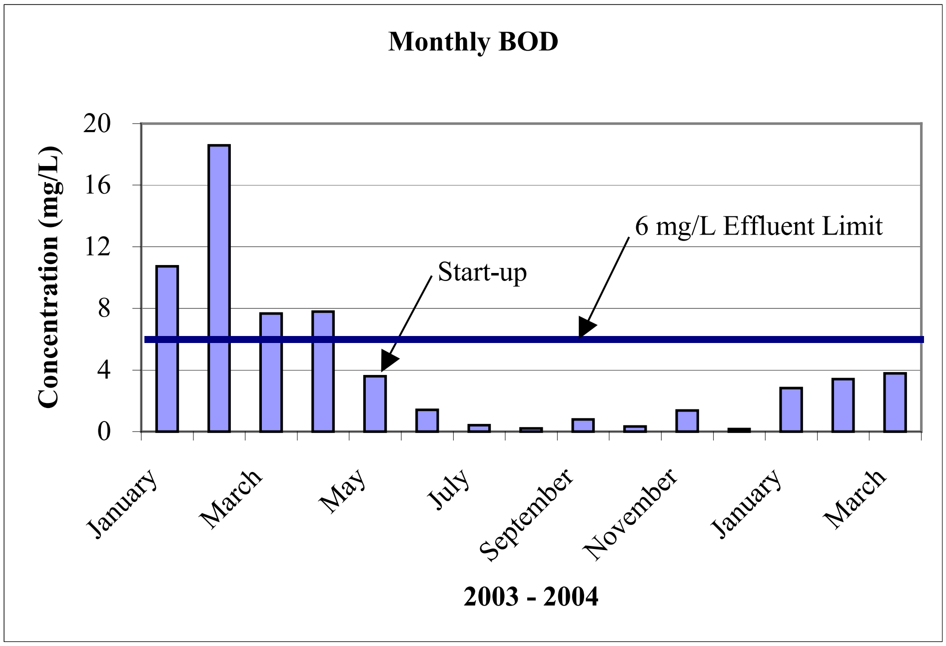
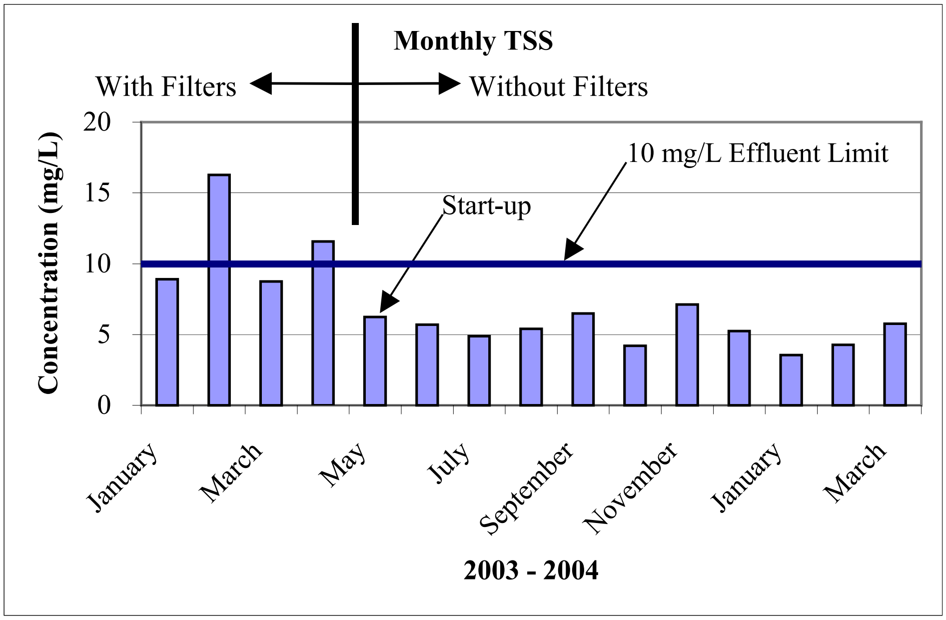


Figure 11 – Ripon WWTF Effluent TSS Performance



SUMMARY

The City of Ripon faced uniquely challenging demands on its wastewater treatment system. High strength industrial discharges, and organic loading that vary by a factor of 4 to 1, placed inordinate stress on the aging wastewater treatment system. High organic loadings create periods of nutrient deficiency that further affect the biological treatment process.

The use of ORP probes for controlling the oxidation ditch aeration system and for pacing supplemental nutrients produces consistent treatment process conditions and contributes to low effluent phosphorus and nitrogen levels. The treatment system produces an effluent with very low levels of the primary nutrients: ammonia, nitrate and phosphorus, significantly reducing nutrient enrichment of Silver Creek and Big Green Lake.

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RESEARCH AND DEVELOPMENT

Research and Development

LANDY–7 Aerator

WESTECH

HISTORY

Landustrie BV has been a pioneer in the technology of slow speed surface aerators since the 1960's. The LANDY-F impeller from Landustrie has been extensively tested and later certified for use in oxidation ditch systems by the Carrousel^{TM} patent holder, DHV Water BV. Hydraulic models were then developed from full-scale installations to predict the channel velocity given the basin dimensions, proper impeller selection, impeller submergence, and aerator horsepower. Using this hydraulic model, Landustrie has installed their LANDY-F impeller throughout the world. With over 500 surface aerator installations and their research and development program, Landustrie has established themselves as a leader in surface aeration technology.

RESEARCH AND DEVELOPMENT

Landustrie continues their effort to advance impeller technology since they first started over 40 years ago. Landustrie conducts research and development of surface aerators with the use of their 500,000-gallon test tank in Sneek, Netherlands pictured below. The experienced engineers at Landustrie have the ability to test the oxygen transfer efficiency, mixing efficiency, torque, vibration, axial forces, and radial forces. Landustrie has also been contracted by direct competitors to test other types of impellers over different operational ranges. Over the past six years, Landustrie has conducted several studies on their next generation LANDY-7 impeller. From their test tank data and full-scale testing at several wastewater treatment plants, Landustrie can officially document and guarantee the benefits of the new LANDY-7 impeller.

LANDY-7 BENEFITS

- INCREASED O.T.E. = 3.8 LB O_2/HP/HR
- INCREASED MIXING EFFICIENCY
- REDUCED AXIAL LOADS
- SIGNIFICANTLY REDUCED RADIAL LOADS
- REDUCED TORQUE LOADS

Research and Development

LANDY–7 Aerator

PLANT CASE STUDY

In 1997, for their hometown of Amersfoort, NL, DHV Water BV consulted to install a Carrousel^{TM} 2000 oxidation ditch. After a successful bid against Hubert and Spaans, Landustrie provided (4) 132 kW LANDY-F surface aerators for this installation to meet the required oxygen demand. In a recent expansion of this wastewater plant, Amersfoort elected to duplicate the existing oxidation ditch and double the plant capacity. Based on their research, Landustrie proposed to meet the same oxygen demand as required before with (4) 110kW LANDY-7 surface aerators. In order to satisfy Amersfoort, Landustrie was required to provide a Performance Guarantee. The client and engineer performed the clean water oxygen transfer test on the LANDY-7 aerators. The field-testing revealed that the LANDY-7 impellers provided the required amount of oxygen and concluded that the lower power units using the LANDY 7 aerator could provide the same amount of oxygen as the existing aerators that have more installed power. Amersfoort has been happy with their lower power cost, while achieving the same treatment.

LANDUSTRIE AND WESTECH ENGINEERING

WesTech Engineering has cooperated with Landustrie BV in a mutually beneficial license agreement since 1996. The experience, research, and development of surface aerator technology have been transferred to WesTech to complement our environmental and process solutions already offered here in the United States since 1973. WesTech has supplied process calculations, oxidation ditch designs, hydraulic model information, and surface aerators for over 30 USA oxidation ditch installations. Based on the latest research and testing by Landustrie, WesTech will now promote the certified benefits of the LANDY-7 impeller. Existing treatment plants have already begun to inquire about increasing their oxygen transfer efficiency simply by replacing their old impellers with the new LANDY-7.

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SAMPLE SPECIFICATIONS

SECTION ________ - OXYSTREAM™ ADVANCED BIOLOGICAL NUTRIENT REMOVAL SYSTEM

0.1 GENERAL

A. DESCRIPTION

1. The Contractor shall furnish and install ___ biological nutrient removal (BNR) system(s) including but not limited to, slow speed surface aerators, vertical mixers, bypass channel flow gates, adjustable effluent weir gates and an automated control system.

2. Furnish ____ slow speed surface aerator(s) (__ per ditch). The equipment shall include motor, gear reducer, impeller with shaft and coupling, anchorage studs and fasteners. The aerators shall be mounted on fixed platforms and shall be designed to both oxygenate and mix the oxidation ditch contents.

3. Furnish ____ vertical turbine mixer(s) (__ per anoxic zone). The equipment shall include motor, gear reducer, impeller with shaft and coupling, anchorage and fasteners. The mixer shall be mounted on a fixed platform and shall be designed to maintain a uniform MLSS within the zone.

4. Furnish ____ flow control gate(s) (__ per ditch) suitable for installation on the concrete wall of the bypass channel. Each mechanism shall be of the hand wheel driven gear drive type, with 112.5 degree travel in forward and reverse direction. The equipment furnished for each gate shall include: stand, gear reducer, rotating shaft, position plate/arm and lock pin, guide bearings, flow vane, stops, fasteners and anchor bolts. The flow control gate is designed to direct and control the flow from the oxidation ditch basin to the upstream anoxic basin.

5. Furnish ____ manually adjustable effluent weir gate(s) (__ per ditch) suitable for installation in the effluent chamber as shown on the drawings. Each gate assembly shall be hand wheel driven using a worm-gear type design. The gate shall have a minimum vertical adjustment of 12 inches. The weir gate assembly will include the necessary frame and seals for a complete assembly.

6. Furnish an Advanced OxySTREAM™ Control System (AOCS), consisting of one dissolved oxygen system for each basin, variable frequency drive (VFD) units for the aerators, and any other control equipment as required by the Manufacturer.

7. All the equipment specified under this Section and the Circular Clarifier section shall be furnished by a single, reputable Manufacturer who meets the experience requirement, as specified in paragraph 1.5.1, and is qualified in the manufacture of said equipment, as specified in paragraph 2.1.1.

B. SUBMITTALS

1. Submit for review the following:

    a. Certified general arrangement drawings showing all important details and materials of construction, dimensions, loads on supporting structures and anchorage location.

    b. Complete data on motors, gear reducers, and required accessories. Data shall include gear reducer calculations and actual service factors.

c. Wiring diagrams and electrical schematics for all control equipment to be furnished.

d. A written statement that shall guarantee the oxygen transfer efficiency and average channel velocities.

e. Total weight of the equipment including the weight of the largest item.

f. Oxygen transfer and power curves illustrating the operational capabilities of the equipment over a varying submergence range.

g. Certified oxygen and horsepower data from a minimum of four (4) separate installations demonstrating that the mechanical aerators are capable of providing 3.5 lb O_2/HP-hr based on the motor output power at standard transfer conditions. Oxygen transfer data shall be provided from a full-scale aeration basin operating as an oxidation ditch. The tests shall be of the Clean Water Oxygen Transfer type in accordance with ASCE or the applicable DIN standards. Tests from basins that are not operating as an oxidation ditch shall not be acceptable.

h. Written certification from Landustrie Sneek BV that the proposed vertical shaft aerators are approved for use in the oxidation ditch as shown on the contract drawings. Landustrie Sneek BV is an approved supplier of the LANDY impeller for installation in closed loop oxidation ditch configurations by recognized independent process consultants. The third party certification is documented as well as evidenced by over 100 successfully operating installations. Aerators submitted from non-approved aerator manufacturers will not be acceptable. The supplier of the equipment shall be responsible for coordinating the review of aeration equipment submittals by the Aerator Licensor to verify that proper performance is achieved. The written certification shall include a guarantee that the equipment designed for this project will meet the velocity requirements as specified.

i. To show evidence of being able to provide the quality of equipment and services described in this specification, the equipment supplier shall submit their quality system ISO 9001 certification. The quality procedures shall provide for a means of qualifying all sub-vendors and shall specify that the fabrication facility is a critical vendor and shall require inspection. The quality system shall be audited by a third party independent inspector. Certification shall remain in effect throughout the project start-up.

C. PROCESS DESIGN CRITERIA

1. Oxidation ditch shall conform to the following:

a. Design Flow Rate: MGD

b. Biological Oxygen Demand (BOD)
Design (influent/effluent): mg/l

c. Total Suspended Solids (TSS)
Design (influent/effluent): mg/l

d. Total Kjeldahl Nitrogen (TKN)
Design (influent): mg/l

e. Total Nitrogen (TN)
Design (effluent): mg/l

D. AERATION PERFORMANCE REQUIREMENTS

1. The aeration equipment shall be capable of operating at the specified liquid levels of mixed liquor in the oxidation ditch so that oxygenation and power draw will vary as desired to respond to load variations seen by the plant. The mixing equipment shall be capable of operating at the specified liquid levels of mixed liquor in the system and provide adequate mixing within the separate zones.

2. Oxygen Transfer: Each aerator shall be capable of developing no less than 3.5 lb. O_2/HP-hr based on the (aerator to water) output power at standard transfer conditions. (Tap water, 20 degrees C, atmospheric pressure, zero dissolved oxygen DO, $\alpha=1$, $\beta=1$).

3. Mixing Velocity: The aeration equipment shall be capable of maintaining an average channel velocity of 1.0 fps with aerator(s) operating at full power.

E. QUALITY ASSURANCE

1. The proposed supplier shall have a minimum of 15 years experience in the design, application, and supply of surface aerators in wastewater treatment plants, and shall submit a list of no less than 25 operating installations as evidence of meeting the experience requirement. The manufacturer shall certify to not less than five (5) successful operating installations in the United States using the same or similar size equipment as specified herein as evidence of meeting the experience requirement.

2. In the event the above experience criteria and quality assurance, as required by the information provided in the submittals and other quality criteria, cannot be satisfied, the proposed equipment supplier shall provide a performance bond to the City. The performance bond shall be for an amount equal to 150% of the bid price of the aeration equipment. The performance bond shall remain in effect for two years from final acceptance of the equipment by the City. Additionally, the aeration equipment supplier shall employ the services of an independent laboratory to perform full-scale clean water oxygen transfer efficiency and channel velocity testing, in the presence of the Engineer/City. The cost of these tests will be paid by the Contractor. If the results do not meet the required performance, the Contractor shall have 20 days to propose changes that meet the approval of the Engineer, and 60 days to make these changes at no cost to the City. The system shall then be re-tested at the Contractor’s expense. If the system again fails to meet the required performance, the Contractor shall replace the aeration equipment with that of another approved manufacturer that will perform, at no cost to the City.

3. The equipment supplier shall submit to the engineer for approval a minimum of 14 days prior to the bid opening a process guarantee. Said guarantee shall be valid for a period of 12 months from the date of plant start-up. A single manufacturer shall supply and be

responsible for the performance of the activated sludge system including the oxidation ditch system, clarifier equipment and automated control system.

F. WARRANTY

1. Warranty: A written supplier's warranty shall be provided for the equipment specified in this section. The warranty shall be for a minimum period of five (5) years from start-up or 66 months from time of equipment shipment, whichever comes first. Such warranty shall cover all defects or failures of materials or workmanship which occur as the result of normal operation and service except for normal wear parts.

0.2 - PRODUCTS

A. MANUFACTURER

1. The oxidation ditch equipment shall be as manufactured by the following:

    a. WesTech Engineering, Inc.; Salt Lake City, UT.

    b. Or Engineer pre-approved equal.

2. All pre-approval packages must be submitted to the Engineer 14 days prior to the bid opening. Any pre-approval packages that do not conform to the specifications and/or do not meet the pre-approval deadline will be rejected.

B. GENERAL DESIGN

1. Description: The aerator shall be a fixed, slow speed, mechanical surface aerator suitable for operation in an oxidation ditch. The aerator shall consist of a drive motor, gear reducer, impeller shaft, and a non-clogging open type vaned impeller. The surface aerator shall be of fully welded steel construction consisting of an inverted cone shaped impeller. The aerator shall be designed to add air to the oxidation ditch and keep a specified mixed liquor velocity through the cross section of the oxidation ditch.

2. Materials: All steel shall conform to the requirements of ASTM A36. Steel pipe used for the shaft shall conform to ASTM A53. Steel items shall be provided with a minimum thickness of ¼ inch.

3. Fabrication: Shop fabrication and welding of structural members shall be in accordance with the latest edition of the "Structural Welding Code", AWS D1.1, of the American Welding Society. All welded connections shall develop the full strength of the connected elements and all joined or lapped surfaces shall be completely seal welded with a minimum 3/16 inch fillet weld. Intermittent welding shall <u>not</u> be allowed.

4. Edge Grinding: Sharp projections of cut or sheared edges of ferrous metals shall be ground to a radius by multiple passes of a power grinder as required to ensure satisfactory coating adherence.

5. Surface Preparation/Coating: All iron and steel surfaces, except the motor and gear reducer, shall be field cleaned and painted to ensure paint compatibility and assign unit responsibility for the coating system.

6. Structural Design: All structural members and connections shall be designed so that the unit stresses will not exceed AISC allowable stresses by more than one-third when subject to either the toque load under startup or the dynamic loading of the equipment operating under full load. All steel design shall be in accordance with the AISC Manual of Steel Construction, latest edition, and the Uniform Building Code (UBC), latest edition.

C. AERATORS

1. MOTORS

   a. Each aerator shall be driven by an inverter duty, ___ HP, TEFC, Class F insulation, constant torque motor, wired for 460V, 60 cycle, 3-phase current. The nominal motor speed shall be 1800 rpm.

   b. Each motor shall be equipped with a suitably sized space heater to prevent condensate from forming while the motor is not running. The space heater shall operate on 120 VAC.

   c. Each motor shall be equipped with a normally closed thermostatic heat protection device to protect the motor from overheating during operation. The unit shall immediately stop the aerator drive motor in the event of excessive heat buildup.

2. Gear Reducer

   a. Each gear reducer shall be of the helical or spiral-bevel gear type. Worm gearing will not be allowed. The gear reducer shall be sized with a minimum service factor of 2.5 times the motor nameplate horsepower rating in accordance with applicable American Gear Manufacturers' Association (AGMA) standards when each unit is operating at full load motor horsepower, 24 hours a day continuous running under moderate shock loads. The efficiency of the gear reducer shall not be less than 94% based on the input horsepower. The gear reducer shall be specifically designed for vertical input and output shaft operation.

   b. The gear reducer housing shall be of cast iron or fabricated steel construction including suitable lifting lugs. The housing shall be constructed of high tensile strength cast-iron conforming to ASTM A48 Class 30, minimum or fabricated steel with integral dry well construction. The housing shall be designed to withstand all loads imposed from the operation of the equipment. The entire gear reducer assembly shall be finish painted by the reducer manufacturer at the factory with a corrosion-resistant paint to provide additional protection against moisture and contaminants. The name plate shall be stainless steel.

   c. Gear reducer bearings incorporated within the reducer unit shall have a B-10 bearing design life of 100,000 hours. The reducer bearings attached directly to the output shaft shall have a B-10 bearing design life of 250,000 hours.

d. Lubrication shall be accomplished by an integral mechanical oil circulating pump externally accessible and driven directly by one of the gear trains. The lubrication system shall incorporate a reliable oil flow cutout switch device which will immediately cut power to the aerator motor and transmit an alarm signal to the motor control center in the event of insufficient lubrication. All gears shall be provided with an oil reservoir for instant lubrication during starting. The gear reducer housing shall be provided with an oil sight glass or dip stick and oil flow indicator to observe oil level and effectiveness of the pump while the unit is in operation. An oil drain with necessary fittings shall be provided and installed allowing clearance for a container at the outlet. The Contractor shall be responsible for supplying the initial lubricants required for startup, as well as the first change of oil.

e. All bearings and gear meshes shall be oil-lubricated except for the takeoff bearing which shall be grease-lubricated. The takeoff bearings located on the output shaft shall utilize dry-well construction to prevent oil contamination of the process stream. The dry-well construction shall incorporate a v-ring and an oil seal to prevent oil leakage down the output shaft. Friction-type oil seals will not be acceptable. All grease lubrication lines shall be fed from fittings accessibly located above the platform supporting the equipment.

f. Each gear reducer shall be equipped with a suitable oil-immersion-type heater for pre-heating the lubrication oil prior to startup. The heaters shall have an automatic thermostatic control and shall operate on 120 VAC.

3. Impeller with Shaft and Coupling

a. Each impeller shall be a fully welded, ¼ inch minimum steel construction, consisting of a closed, inverted cone-shaped impeller with blades radiating outward from the center and extended up the cone side. The impeller blades shall be welded to the rolled inverted cone assembly. Impellers utilizing blades welded directly to the impeller shaft will not be allowed. Additionally, impellers with open design of the blades or cone that allow the wastewater to flow through and have a potential for fouling by rags will not be permitted. The outer ends of the blades shall be shaped to enable air-intake slots behind the blade-tips. The cone shall be welded around a heavy center hollow tube and supported by a circular plate, welded on the inside of the cone and the center tube. The center tube shall be provided with a neck flange for connecting the aerator to the gearbox coupling half. The pipe shaft and impellers shall be constructed so that no field welding is required. The impeller shall operate with a maximum tip speed of 20 fps. The maximum impeller speed shall be 35 rpm. The impeller shall present a minimum amount of edge perpendicular to the flow to prevent the attachment of solid materials. The gear reducer shall be connected to the impeller by a rigid cast iron type coupling.

D. MIXER

1. Motors

   a. The mixer shall be driven by a single speed, ___ HP TEFC with Class F insulation, constant torque motor, wired for 480V, 60 cycle, 3-phase current. The nominal motor speed shall be 1800 rpm.

   b. The motor shall be equipped with a normally closed thermostatic heat protection device to protect the motor from overheating during operation. The unit shall immediately stop the mixer drive motor in the event of excessive heat buildup.

2. Gear Reducer

   a. Each gear reducer shall be of the helical or spiral-bevel gear type. Worm gearing will not be allowed. The gear reducer shall be sized with a minimum service factor of 2.0 times the motor nameplate horsepower rating in accordance with applicable American Gear Manufacturers' Association (AGMA) standards when each unit is operating at full load motor horsepower, 24 hours a day continuous running under moderate shock loads. The efficiency of the gear reducer shall not be less than 94% based on the input horsepower. The gear reducer shall be specifically designed for vertical input and output shaft operation.

   b. The gear reducer housing shall be of cast iron or fabricated steel construction including suitable lifting lugs. The housing shall be constructed of high tensile strength grey cast-iron conforming to ASTM A48 Class 30, minimum or fabricated steel. The housing shall be designed to withstand all loads imposed from the operation of the equipment. The entire gear reducer assembly shall be finish painted by the reducer manufacturer at the factory with a corrosion-resistant paint to provide additional protection against moisture and contaminants. The name plate shall be stainless steel.

   c. Gear reducer bearings incorporated within the reducer unit shall have a B-10 bearing design life of 100,000 hours.

   d. Lubrication shall be accomplished by splash lubrication. All gears shall be provided with an oil reservoir for instant lubrication during starting. The gear reducer housing shall be provided with an oil sight glass or dip stick. An oil drain with necessary fittings shall be provided and installed allowing clearance for a container at the outlet. The Contractor shall be responsible for supplying the initial lubricants required for startup, as well as the first change of oil.

   e. All bearings and gear meshes shall be oil-lubricated except for the takeoff bearing which shall be grease-lubricated. The takeoff bearings located on the output shaft shall utilize dry-well construction to prevent oil contamination of the process stream. All grease lubrication lines shall be fed from fittings accessibly located above the platform supporting the equipment.

3. Impeller with Shaft and Coupling

    a. The impeller shall be a high efficiency axial flow type impeller. The assembly shall be made up of an impeller hub with bolt-on blades. Axial flow impellers shall have a hub with three blades evenly spaced on the hub. The impeller shaft shall be sized so the maximum operating speed of the impeller and shaft does not exceed 40% of the first natural critical speed. The coupling assembly shall be used for connecting the gearbox output shaft and the vertical impeller shaft. The upper coupling half shall be keyed on the speed reducer output shaft and shall be held in place by a retainer washer and bolt in the end of the reducer output shaft.

E. FLOW CONTROL GATE

1. Worm Gear Reducer: The worm gear operator shall be of heavy duty construction, totally enclosed on a cast iron housing and provided with adequate seals to protect the interior of the housing. The housing shall be designed so that all gears and bearings are grease packed and factory sealed to prevent condensate formation. The gear shall be designed to operate under the full load as applied for the rotating gate. The reducer shall be equipped with a 20 inch steel hand wheel and require no more than 25 revolutions to rotate the gate a full 112.5 degrees in one direction.

2. Gate Components: The reducer shall be supported on a steel stand that is anchored to the concrete floor or side wall by cinch type 304 stainless steel anchors. The stand shall be of proper height to allow the operator a convenient grip on the handle for clockwise or counter clockwise turning.

3. Rotating Gate Assembly: Gate shall be constructed from ¼ inch steel plate properly stiffened with rib extensions and end flares. The gate shall include a revolving shaft assembly fixed between three guide bearings mounted to the floor stand. The floor bearing shall be a thrust type aligned bearing, supporting the entire weight of the unit. The upper guide bearings shall be an integral part of the support stand and shall be mounted just below the worm gear reducer. The center guide bearing, if required by the shaft length, shall be mounted just above the water surface on the lower part of the shaft and shall be field aligned after installation of all other component, assuring proper rotational capacity.

F. EFFLUENT WEIR GATE

1. Actuator Assembly: The actuator assembly shall include a dual reducer system connected by an actuator-connecting shaft and controlled by a single 12” handwheel. The actuator-connecting shaft shall include the necessary support bearings to prevent binding during operation.

2. Weir Gate Components: The weir gate shall be complete with support frame, guide bearings and seals. The guide bearings will be UHMW and will be an integral part of the frame. The seals shall be of the bulb type and extend along the sides and the bottom of the weir gate. The weir gate shall be factory assembled and adjusted and shall include 304SS epoxy anchors.

3. Weir Gate Assembly: Gate shall be constructed from ¼ inch steel plate properly stiffened with rib extensions and supports. The gate shall include a pin connection for the dual actuators designed to support both the vertical load and the hydraulic load. The gate assembly will provide for a minimum of 12 inches vertical adjustment

G. SYSTEM CONTROL

1. The primary objective of the AOCS controller will be to adjust aerator power input to match the oxygen demand using Dissolved Oxygen (DO) concentration as the primary control parameter. The DO level will be monitored at the location shown on the Plans. The rotational speed of each aerator, Aerator run status, Aerator run time, Aeration system on status, Normal - Low - High Dissolved oxygen status, Power on, High motor temperature and Low reducer oil pressure/flow shall also be monitored. All monitored parameters shall have separate outputs available for the plant SCADA system.

2. The AOCS controller will use the DO signal to pace the VFD in “auto mode” while the operator will manually control the VFD speed using the AOCS operator interface module in the “manual mode.” The entire system shall be designed to restart after power outage if there are no alarm conditions that would normally shut the unit down. Status and alarm lights with an audible alarm shall be included.

H. AOCS CONTROLLER

1. The AOCS system will include the following I/O’s:

INPUTS	OUTPUTS FURNISHED FOR SCADA/MONITORING/CONTROL
Power	
Aerator Oil Pressure/Flow	Aerator Low Oil Pressure/Flow Alarm
Aerator Motor Temperature	Aerator Motor High Temp Alarm
	Aerator Space Heater control
D.O. Signal (4-20mA)	D.O. Analog Signal
	High D.O. Alarm
	Low D.O. Alarm
Run Signal from VFD	Aerator Speed (4-20mA) to VFD
	Aerator Run to VFD
	Aerator System On to VFD
	Aerator Auto Speed Select to VFD

2. Each aerator will be designed with motors that are rated per NEMA MG-I, Section IV, Part 31.40.4.2 with allowable 1600V peaks and rise times greater than or equal to 0.1 microseconds. The DO levels will have a defined band of acceptable values between a lower limit, DO_L, an upper limit, DO_U, and a target setpoint DO_S. These limits will be user-defined but factory preset. The AOCS system factory set algorithms shall be the responsibility of the surface aerator supplier and shall be specifically designed for the installed system. The controls shall be designed so that, when the DO falls within the acceptable range, the system will maintain that operational point. The system will recheck the parameters on a pre-set, but user specified time period, and make changes or suspend action as necessary.

a. When the measured dissolved oxygen in the basin is greater than DO_U, the speed of the lead aerator will be decreased by a pre-set (user adjustable) frequency change. The system will be allowed to stabilize for a pre-set (user specified) time period. If the DO level is still above the acceptable limit at aerator minimum speed, the speed of any additional aerators (if supplied) will be decreased in the same sequence and amount. If the DO level is still above the acceptable limit and multiple aerators are supplied, the system will turn off aerator(s) to a predetermined acceptable process level that will maintain the minimum allowed channel velocity. If the DO level is still above the acceptable limit, the lead aerator will run at the lowest possible speed for process control and the High Dissolved oxygen alarm will be energized. No further automatic decreases will be made.

b. When the measured dissolved oxygen in the basin is less than DO_L, then the converse procedure will commence. The lead aerator speed will be increased until it reaches full speed. Multiple aerator systems will add aerator(s) to the sequence at the designated speed to bring the measured DO within the acceptable operating range. Further increases in power will be accomplished by increasing the speed of any aerators that are VFD controlled to come to full speed. No additional increases in power and oxygen input will be made when all aerators are running at their full speed and the Low Dissolved Oxygen alarm will be energized.

3. The AOCS controller shall be designed to provide high reliability and factory programmed with logic functions to match the process and mechanical operational requirements of the OxySTREAM™ System aerator(s) / dissolved oxygen system / VFD(s) as a complete system. The controller will allow the system to operate the equipment without excessive speed changes or excessive switching. The supplier shall assume single source responsibility for the system and shall provide the AOCS controller in a single NEMA 12 enclosure, as manufactured by Hoffman, rated for 120 volt, 60 hz power, complete with a fused terminal block for disconnecting power. The panel shall be located as shown on the plans. Additionally, programming shall include delays as necessary on startup of the unit. The AOCS controller shall be designed with programmable keypad to allow operator modification of specific setpoints and timing functions. D.O. normal settings can be changed via keypad input, and upon user selection of the Manual mode, the AOCS operator interface module shall also be capable of controlling the VFD speed.

I. DISSOLVED OXYGEN MONITORING EQUIPMENT

1. The dissolved oxygen (D.O.) monitoring system shall consist of a sensor, analyzer, and auxiliary equipment to facilitate mounting the D.O. monitoring system. One probe and one monitoring system per basin shall be furnished.

2. The system shall output a signal proportional to the dissolved oxygen level and the measured temperature. The monitor shall meet NEMA 4X requirements and shall be supplied with 25 feet of cable. The system shall be able to display all of the following parameters:

a. dissolved oxygen concentration
b. temperature
c. relay status
d. selected salinity at calibration
e. selected value for alarm relays (high and low dissolved oxygen)
f. error pending and error log.

The system shall be able to perform automatic calibration of the dissolved oxygen monitoring system. The Power supply shall be 115 VAC, +10%, -15%.

3. The dissolved oxygen sensor shall be installed on a galvanized mounting bracket to be suspended from the railing. The mounting brackets shall be constructed to allow for easy calibration or exchange of the sensor without tools.

J. VARIABLE FREQUENCY DRIVES

1. The drives shall be designed to meet the following specifications and regulatory requirements:

NFPA 70-US National Electrical Code
NEMA ICS 3.1 - Safety standards for Construction and Guide for Selection, Installation and Operation of Adjustable Speed Drive Systems.
NEMA 250 - Enclosures for Electrical Equipment
UL 508C - Underwriters Laboratory
CAN/CSA-C22 No. l4-M9l. - Canadian Standards Association.

IEC 146 - International Electrical Code.
IEC 801 - EN Standard/CE marked for EMC directives

Emissions		Immunity
EN	50081-1	EN 50082-1
EN	50081-2	EN 50082-2
EN	55011 Class A	IEC 801-1,2,3,4,6,8
EN	55011 Class B	(per EN 50082-1,2)

Additionally, C-UL marking to provide an approved listing for both United States and Canadian users shall be provided. The Manufacturer will furnish the product as listed and classified by Underwriters Laboratories as suitable for the purpose specified and indicated.

2. The drive shall be manufactured by Allen-Bradley, Reliance or equal. The unit shall be of the PWM Adjustable Frequency Drive, 16 pulse minimum, design and certified to the ISO-9001 Series of Quality Standards.

3. The drive shall be enclosed in a Hoffman NEMA 12 enclosure suitable for wall mounting in the control building and be self adjustable to accept an input voltage range between 380-48OVAC, three phase +/-10%. Displacement power factor shall range between 1.0 and 0.95, lagging, over the entire speed range (0.80 for 0.5-Shp/0.37-3.7kw, 200-480V drives). The efficiency of the drive shall be a minimum of 97% at full load and speed. The equipment must be capable of operation in the following environment:

Storage ambient temperature range: -40 C to 70 C (-40 to 158 F).

Operating ambient temperature range: 0 C to 40 C (0 to 109 F) without derating. The relative humidity range is 5% to 95% non-condensing. Operating elevation: up to 1000 Meters (3,300ft) without derating.

The inverter section shall be a pulse width modulated (PWM) waveform, 16 pulse minimum, using latest generation IGBTs. The drive shall be programmable or self adjusting and shall be designed to operate on an AC line which may contain line notching and up to 10% harmonic distortion. The drive shall include a Human Interface Module with integral display to show drive operating conditions, adjustments and fault indications.

Accel/Decel settings shall be programmable and all adjustments shall be stored in nonvolatile memory (EEPROM). The drive shall allow automatic fault reset and restarts following a fault condition before locking out and requiring manual restart. The time between restarts shall be adjustable from 0.5 seconds to 30 seconds.

Three adjustable set points that lock out continuous operation at frequencies which may produce mechanical resonance shall be provided. A user programmable restart function shall be provided to automatically restart the equipment after restoration of power after an outage. A programmable function shall be provided that selects the reconnect mode of the drive after recovery from a line loss condition. The unit shall be designed with a fault memory and information shall be maintained in the event of a power loss. The drive shall provide Class 20 motor overload protection investigated by UL to comply with N.E.C. Article 430. Overload protection shall be speed sensitive and adjustable for motors with speed ranges of 2:1, 4:1 and 10:1.

The drive shall be designed to provide an option for Start, Stop, Jog, Reverse and Speed Control as an integral part of the Human Interface Module. All control interface cards shall provide input terminals for access to fixed drive functions that include start, stop, external fault, speed, and enable. Outputs for VFD functions are available for SCADA or plant monitoring at the VFD.

K. ANCHORAGE AND FASTENERS

1. Jacking Studs: All jack studs shall be a minimum of 2 inch diameter A307 zinc plated steel and provide a total vertical adjustment of 6 inches. The equipment supplier shall furnish all anchorage, nuts, and washers required for the equipment.

2. Fasteners: All fasteners shall be a minimum of 1/2 inch diameter HDG A325 for high strength connections and 304 stainless steel for all other connections. The equipment supplier shall furnish all fasteners required for the assembly of the equipment.

3. Mounting Plate: Each aerator shall be equipped with a rigid, structural steel mounting plate with a minimum of 1 inch thickness. The mounting plate shall be sufficiently thick to be designed to minimize vibration.

L. COATING

1. Gear reducers and motors shall be furnished with the manufacturer's standard paint system. All ungalvanized fabricated iron and steel surfaces shall be shipped to the site bare steel without preparation. All preparation and painting shall be done on site per the requirements of Section ______.

M. SPARE PARTS

1. Each Aerator
    a. One low oil flow cutout switch
    b. One flexible motor coupling (each size required)
2. Mixer
    a. One low oil level switch
    b. One flexible motor coupling (each size required)

0.3 - EXECUTION

A. SITE STORAGE AND HANDLING OF EQUIPMENT

1. The Contractor shall store the supplied equipment in accordance with the manufacturer's recommendations and instructions. Gear reducers and motors shall be stored in buildings or trailers which have concrete or wooden floor, a roof and fully enclosed walls, and will protected the equipment from dust, dirt, and moisture. Equipment provided with space heaters shall be connected to a temporary power source to provide continuous operation of the heaters until the site is ready for installation. Rotate all shafts with bearings on a monthly basis. The Contractor shall be responsible for work, equipment, and materials until inspected, tested and finally accepted.

B. INSTALLATION

1. The equipment shall be installed properly to provide a complete working system. Installation shall follow the supplier's recommendations.

C. OPERATION AND MAINTENANCE MANUALS

1. The equipment supplier shall furnish ____ copies of operation and maintenance manuals which will be retained at the installation site to assist City plant operators. The manual shall include the supplier's erection and assembly recommendations and a complete list of recommended spare parts.
2. Process Manuals: The equipment supplier shall furnish ___ copies of the Process and Operation Manuals which illustrate proper operational practices for BNR systems.

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These manuals will be retained at the plant and used by the plant personnel for operational practices and recommendations.

D. TESTING

1. The equipment supplier shall provide the service of a qualified representative for two trips and five days to inspect the equipment installation, assist in start-up, test, and instruct plant personnel in the proper operation and maintenance of the equipment.

2. During the start-up of the equipment, the equipment manufacturer shall test the equipment to verify that the velocity requirements have been met. Average velocity shall be determined from an arithmetic average 16 points in a cross section of the channel. These points shall be gathered at four equally spaced points across the width of the tank and four equally spaced points from the liquid level to the tank bottom. Average of all values at the full power condition shall not be less than 1 fps. The Contractor shall construct a bridge spanning the middle of the oxidation ditch to allow a suitable platform for testing to be done.

- END OF SECTION -

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SAMPLE AERATOR DRAWING

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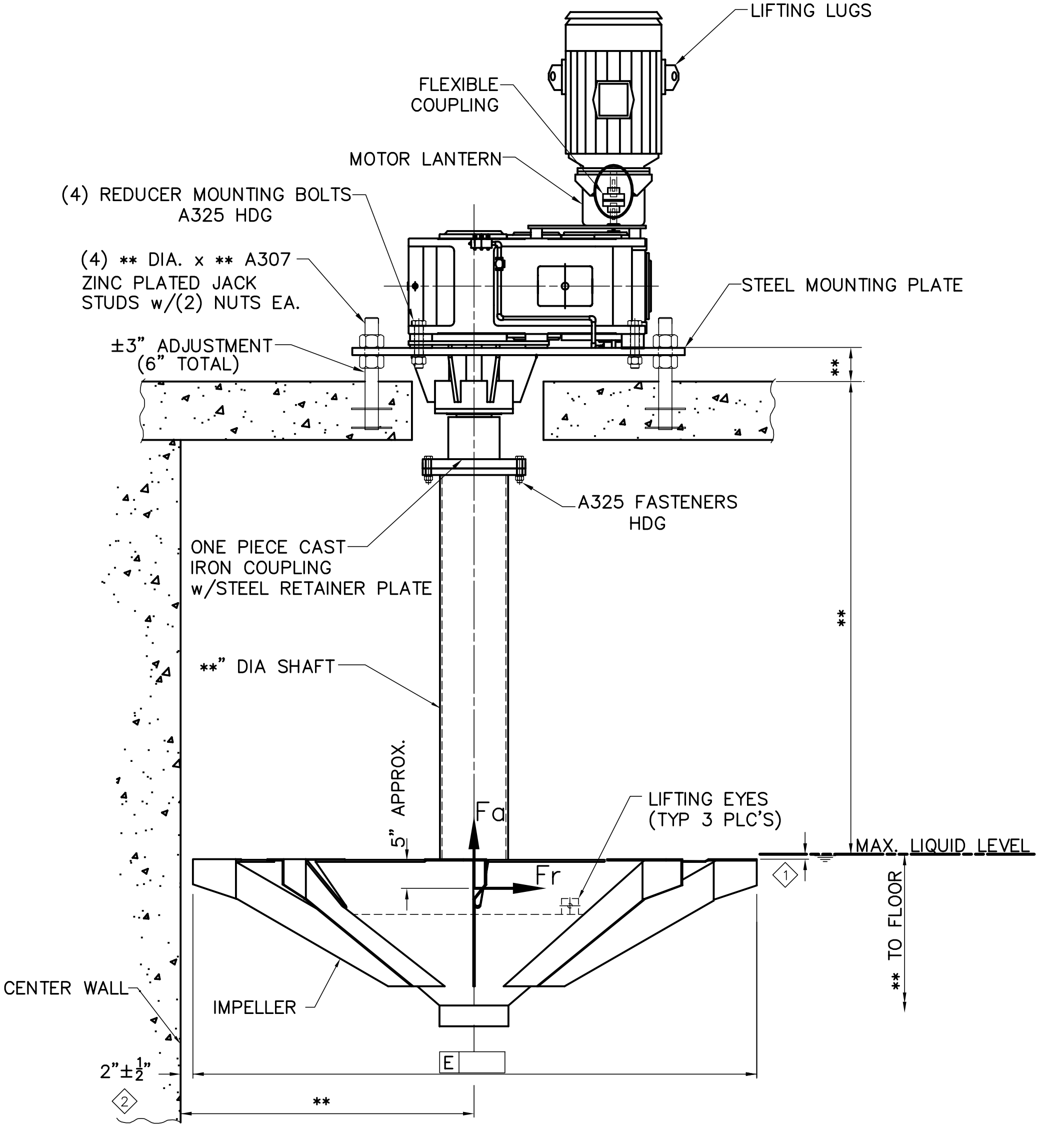
NOTES:

◇1 1. IMPELLER SUBMERGENCE, AS SHOWN, IS BASED ON THE MAXIMUM LIQUID LEVEL. FOR STARTUP LIQUID LEVEL, REFER TO ENGINEERS CONTRACT PLANS.

◇2 2. WALL CLEARANCE OF 2"±½" IS CRITICAL AND MUST BE HELD.

3. TOTAL WEIGHT OF EQUIPMENT – __**__ LBS.
WEIGHT OF SINGLE HEAVIEST ITEM – __**__ LBS.



MOTOR SPECS:

MANUFACTURER: RELIANCE, U.S., OR EQUAL
HORSEPOWER: C
FRAME: __**__
SERVICE FACTOR: _____
INSULATION: CLASS F
ENCLOSURE: TEFC
SPEED: _____ RPM (F/L _____ RPM)
460V/3 PH/60 HZ
B10 BEARING LIFE: _________ HRS
MOUNTING: P BASE
CONDENSATE DRAINS
EFFICIENCY: __**__%
AMBIENT TEMP: 40° C
NORMALLY CLOSED THERMOSTAT
MOTOR WEIGHT: __**__ LBS

OPERATING FORCES

Fa = __**__ LBF DYNAMIC
Fr = __**__ LBF IN ALL DIRECTIONS DYNAMIC

REDUCER SPECS:

MANUFACTURER: HANSEN, MERGER, OR EQUAL
MODEL: __**__
GEAR RATIO: __**__:1
SERVICE FACTOR: ____ MIN.
B10 BEARING LIFE: 100,000 HRS INTERNAL
________ HRS OUTPUT SHAFT
CONSTRUCTION: CAST IRON w/ LIFTING LUGS
OIL DIPSTICK, OIL DRAIN: BALL VALVE ON PIPE NIPPLE
EFFICIENCY: __**__%
MECHANICAL OIL PUMP w/LOW OIL FLOW SWITCH
OIL IMMERSION HEATER
OIL FLOW INDICATOR
REDUCER WEIGHT: __**__ LBS

IMPELLER SPECS:

MANUFACTURER: WESTECH / LANDUSTRIE
MODEL: LANDY D
TYPE: 8 BLADE, OPEN VANE
OPERATION SPEED: F RPM
MATERIAL: MILD STEEL ¼" MINIMUM THICKNESS
IMPELLER WEIGHT: __**__ LBS

NOTES:

1. THE CONFIGURATION AND DATA SHOWN ON THESE DRAWINGS IS FOR INFORMATION PURPOSES ONLY AND SHOULD NOT BE USED WITHOUT FOLLOWING PROPER PROCESS DESIGN CRITERIA.
2. CONCRETE SIZES AND REINFORCING SHOULD BE SIZED BASED ON THE EQUIPMENT OPERATING FORCES.

**3. CONSULT WESTECH FOR FINAL DIMENSIONS AND EQUIPMENT.

PREPARED FOR:
ENGINEER:

SLOW SPEED SURFACE AERATOR
DESCRIPTION

LANDY SURFACE AERATOR				VARIOUS					
MODEL				SIZE		COP16X01	0313 x 32		
11-02	CH	GP	JTR	NONE					
DATE	STD. BY	STD.CHKD.	STD.APPVD	SCALE	DATE	PROJ. BY	PROJ.CHKD.	PROJ.APPVD	

REVISION	BY	CHKD	DATE	LTR

WESTECH

DRAWING NUMBER	PROJECT NUMBER	REV.
AES2XX-LAN		0

GE Energy

even in the middle of nowhere

cogeneration with Jenbacher gas engines

GE imagination at work

cogeneration of heat and power

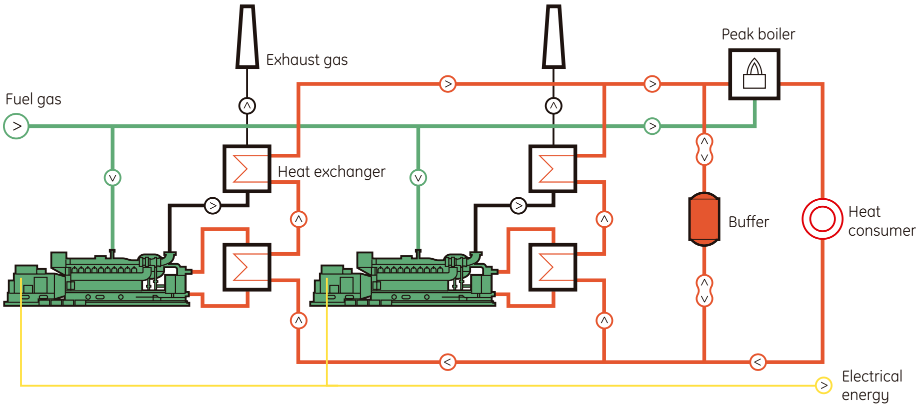
Cogeneration systems – also called combined heat and power or CHP systems – generate both heat and power. Jenbacher CHP systems economically utilize the waste heat incurred during engine operation to generate overall plant efficiencies of more than 90%. This efficient form of energy conversion achieves primary energy savings of roughly 40% by using a gas engine cogeneration system instead of separate power and heat generation equipment. Transportation and distribution losses are also reduced or eliminated as the decentralized energy supply is set up where it is needed.

the Jenbacher concept

The basic structure of a Jenbacher CHP system consists of an engine/generator unit and heat exchangers for the utilization of waste heat. The incorporation of a wide range of heat sources – from engine cooling water, oil and air/fuel gas mixture to exhaust gas – is configured to maximize the benefit to each individual customer.

Cogeneration systems can be supplemented with a boiler system for bridging peak heat demand periods. An additional increase in the operating time and efficiency of the system is made possible by the connection of a heat storage medium. Power plant electrical switch and control systems distribute the electricity and manage the engine, while hydraulic equipment ensures the heat distribution.

The generated power is utilized by the individual facilities (e.g., hospitals) or fed into the public power grid. The thermal energy can be used for both generating heating water and steam production as well as for various types of process heat. Gas engine cogeneration systems are also used for CO_2 fertilization in greenhouses and trigeneration systems (combined generation of heat, cooling and power).



advantages of Jenbacher cogeneration systems

- High electrical efficiencies of up to 43%
- Overall efficiencies (electrical and thermal) of over 90%
- Wide range of power and heat outputs
- Minimum emissions through the patented LEANOX® lean mixture combustion
- Compact design requires a comparatively small footprint
- Specially designed engines for utilization of alternative energy sources (e.g., biogas, landfill gas, coal mine gas, or coke gas)
- Maximum operational safety and availability
- Low investment costs

key figures

A cogeneration plant with 1,000 kWel and 1,250 kWth can meet the following heat demands:

Short-distance heating network	approximately 12,500 m^2 of residential area
Hospital	approximately 150 beds
Building supply	approximately 10,000 m^2 of useful area (floor space)

our competence

The first Jenbacher gas engine was built in 1957. Currently more than 3,270 Jenbacher cogeneration plants with a total electrical output of over 3,500 MW are in operation worldwide. Increases in energy costs, environmental concerns and energy demands will continue to promote the future growth of CHP systems. Jenbacher's innovative cogeneration systems will continue to lead the way.

GE Energy

BASCHNEGGER AMMANN PARTNER

GE Energy's gas engine business is one of the world's leading manufacturers of gas-fueled reciprocating engines, packaged generator sets and cogeneration units for power generation. It is one of the only companies in the world focusing exclusively on gas engine technology.

Jenbacher engines range in power from 0.25 to 3 MW and run on either natural gas or a variety of other gases (e.g., biogas, landfill gas, coal mine gas, sewage gas, combustible industrial waste gases).

A broad range of commercial, industrial, and municipal customers use Jenbacher products for on-site generation of power, heat, and cooling. Patented combustion systems, engine controls, and monitoring enable its power generation plants to meet the strictest international emission standards, while offering high levels of efficiency, durability, and reliability.

GE Energy's Jenbacher product team has its headquarters, production facilities, and 1,000 of its more than 1,250 worldwide employees in Jenbach, Austria.

GEA-13717A

for more information on Jenbacher products

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GE imagination at work

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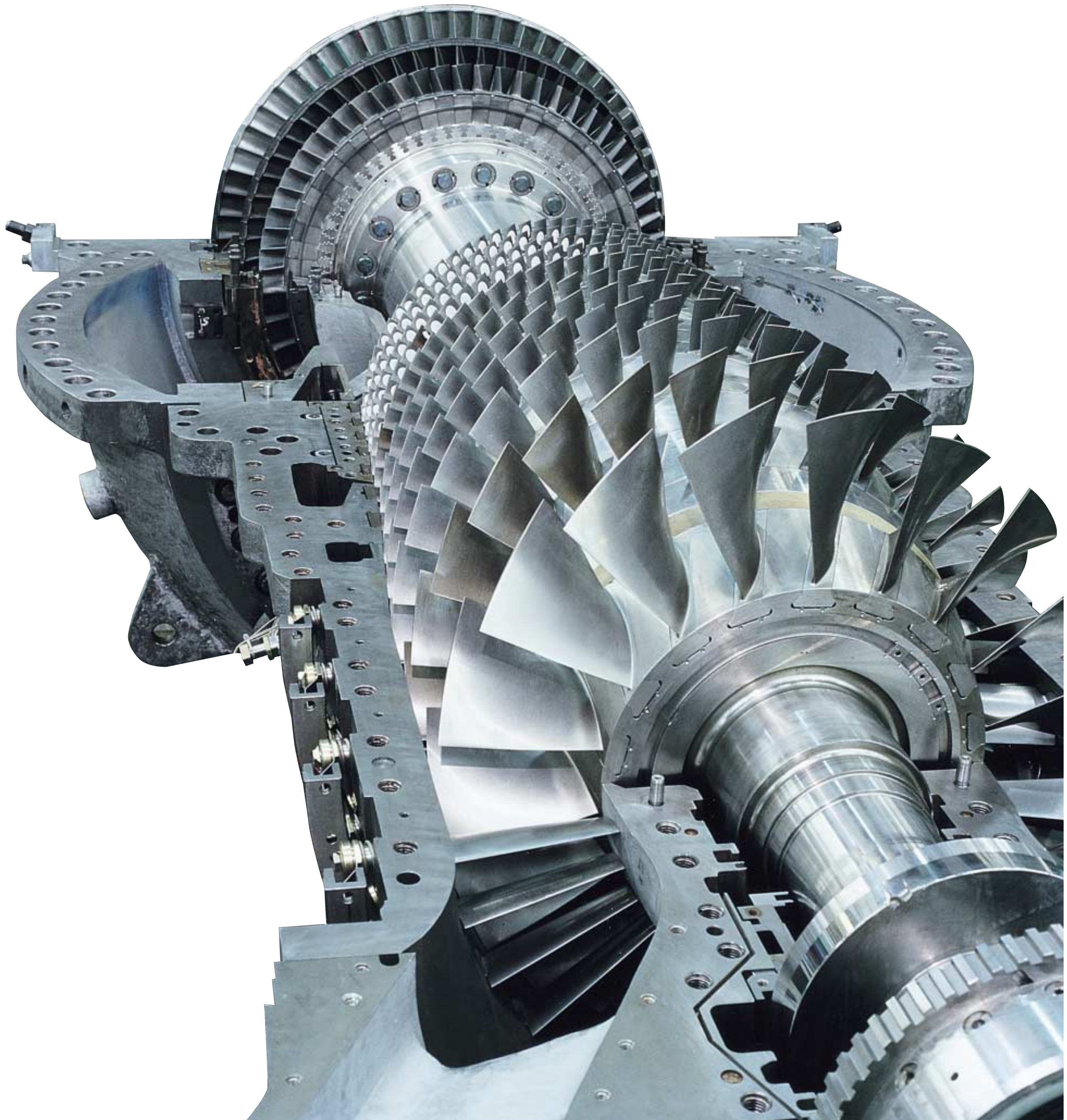
COMK/MARK 839/II - Designed by: Studio Tre Fasi
Printed by: Sagraf - 12-2005

GE
Oil & Gas

GE10-1
Gas Turbine



The GE10 engine family is a 12 MW range heavy-duty gas turbine, available in either a single or a twin-shaft configuration.

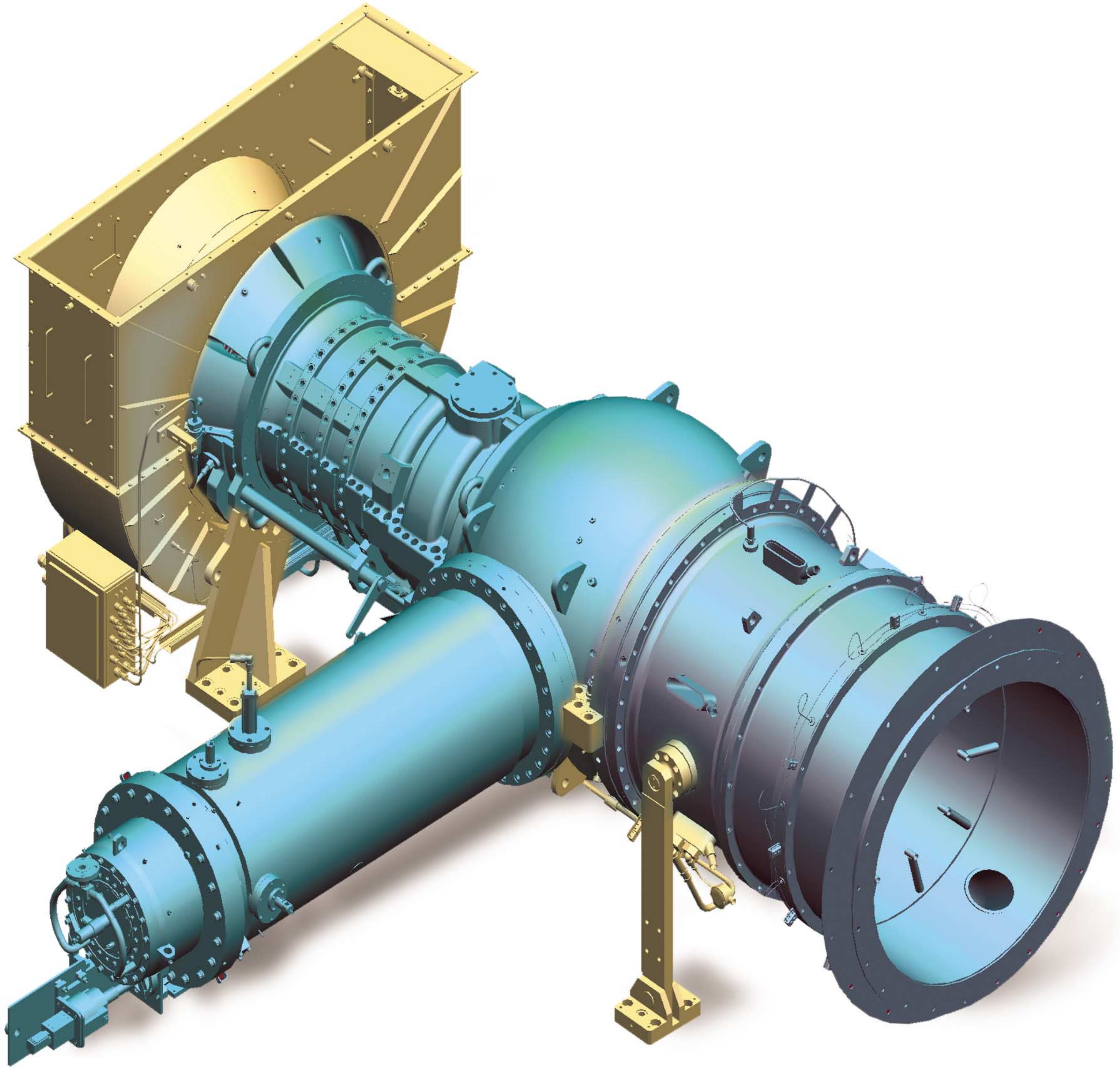
It is the evolution of the field proven PGT10 and incorporates the latest in aerodynamic design, and compact and versatile package arrangements.

The GE10 engine design has been highly refined based on the extensive experience gained operating in all types of environments.

There are many units running under conditions ranging from the cold of Alaska to the heat of the desert and the humidity of the tropics.

Its efficiency and operational flexibility make the GE10 a cost-effective choice for all applications

GE10-1
Gas Turbine



Engine Characteristics

The gas turbine is the well proven GE10-1 Engine, a heavy duty single shaft engine that has accumulated a very large number of fired hours, and has leveraged the experience of the previous PGT10.

The cases are horizontally split and the rotor has a disk architecture.

The combustion system consists of a horizontally positioned single can; the GE10-1 is available in both Diffusion Combustion System and DLN (Dry Low NOx) versions and is able to burn a wide range of liquid and gas fuels, including Low BTU gas and hydrogen.

Fuel Gas System

A typical gas fuel configuration employs shutoff valves for safety reasons and metering valves to control the machine load and CO/NOx emissions. Depending on the level of DLN performance requested, two or three metering valves are needed in order to control gas injection in the various parts of the combustion chamber.

Unit Control Panel

The GE10 control system is standardized to assure a high degree of integration between the turbine and the generator. The system is based on the GE Fanuc RX3i PAC System platform with remote I/O modules.
The Bently Nevada 1701 is installed for the acquisition of data from seismic probes and for humming detection. The control, monitoring and tuning of unit parameters can be performed remotely. Remote data acquisition does not interfere with normal site operations.

Control CAB

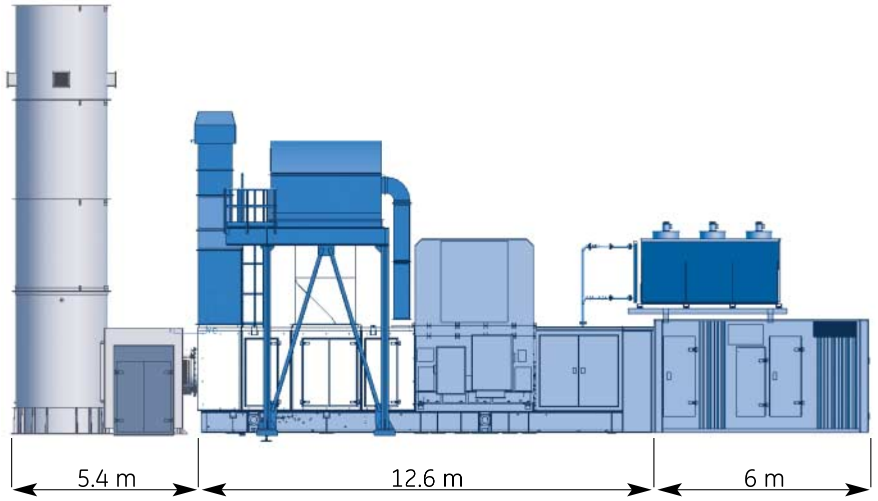
An integrated control cab containing all electrical panels for control and operation of the unit is supplied, including:

- Unit control panel
- Motor control center
- VFD for gas turbine starting
- Generator control and protection panel
- DC panel & battery charger
- Batteries
- On site monitoring system

The cab is provided with an air conditioning system, normal and emergency lighting, a smoke detection system and manual fire suppression bottles.

Air Filter

The air filtration system consists of a “pulse jet type” filter house, an inlet duct and a silencer.
The Pulse Jet system also provides an anti-icing function without any additional hardware.
Filter inspection and replacement of filter cartridges are facilitated by gangways and ladders that are included as part of the scope of supply.



Package Arrangement

The gas turbine enclosure consists of a separate structure and panels mounted on a base plate. Access doors are included for normal maintenance operations and inspections. The ventilation system for internal cooling of the package consists of two 100% axial fans.
The enclosure includes fire & gas detection systems and an automatic CO$_2$ type fire fighting system.
The enclosure guarantees a sound pressure level lower than 85 dBA at 1m.
For indoor applications, an 80 dBA version is available upon request.
The GE10-1 package is designed specifically for power generation applications and is optimized to minimize plant dimensions and to reduce maintenance cost and time.
The single lift architecture minimizes the site installation and commissioning lead time.
The integrated control cab eliminates civil works for the control room and site wiring activities.

Available Options

- Dual Fuel DLN version (liquid + gas fuel)
- 6.6 kV IP55 CACA Electric Generator
- 80 dBA sound pressure level package
- Indoor version
- H_2O oil cooler
- STD exhaust duct (12 m)
- Lubrication stand-by pump
- Control cabinet located alongside the unit
- Additional Pre-Engineered BN1701 for complete vibrational monitoring

Axial Compressor

The compressor is a high Performance, eleven-stage axial flow design with a 15.5:1 pressure ratio derived from GE Aircraft Engine transonic flow aero design technology.
The rotational speed is 11000 rpm with a mass flow of 47 kg/s. The antisurge margin exceeds 25%. Advanced 3D airfoils are used for vanes and blades, and the first three rows of stator blades are adjustable to optimize operability.
The compressor rotor cold side (the fixed point of the gas turbine) accommodates the load flange.
This configuration guarantees reduced flange movement during gas turbine thermal transients.
A patented GECC-1 aluminum ceramic coating is provided for application in marine environments.

Combustion System and Emissions

The combustion system consists of a single, slot-cooled combustion chamber assembly that permits easy maintenance of the hot gas path.
This combustion chamber is able to burn a wide range of fuels, from liquid distillates to residuals, to all gaseous fuels, including low BTU gas. The broad fuel capability of this combustor is due to the variable geometry design patented by GE. A NOx level of 25 ppmvd @ 15% O_2 is guarantee over a wide load range.
DLN Dual Fuel version (liquid + gas fuel) is also available.

Turbine

The single-shaft version is optimized for power generation applications.
The turbine consists of three reaction stages.
In the first two-stages, the hot gas parts are cooled by air extracted from the axial compressor.
The second and third stages have interlocked shrouds to limit tip leakage and blade vibration.

Generator and Gearbox

The unit is equipped with:

- an open, air cooled four-pole 11kV generator (6.6kV CACA also available).
- Jacking oil system
- Anti-condensation heater
- Brushless excitation system
- Seismic probes
- Thermocouple for each bearing and each phase
- Ventilation silencers

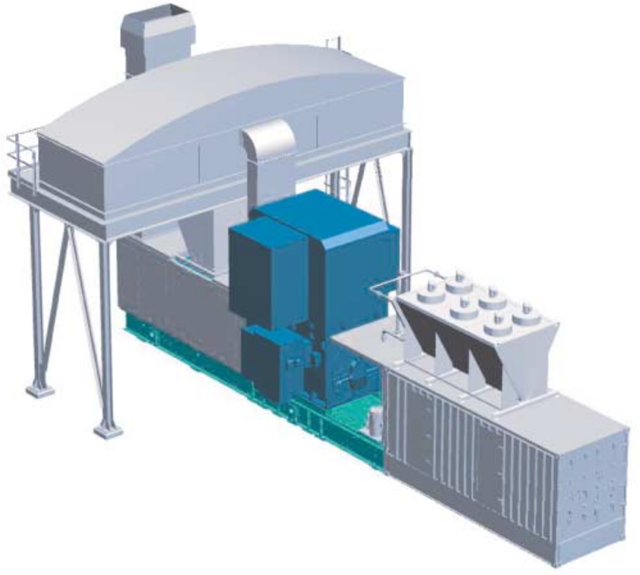
The gearbox is directly connected to the generator and the entire gear is supported by the generator casing without an external coupling.

Lubrication and Bearings

The on-base integrated lubrication system feeds the gas turbine, the speed reduction gear and the driven generator.
The lube oil tank is integral with the gas turbine base plate. The main lube oil pump is a VFD Type and a DC electric motor driven pump is provided for emergency backup.
A stand-by pump identical to the main pump is available as an option in order to allow continuous operation in the event of a main pump failure.
In the standard package configuration, the oil is cooled with an air cooler; a water cooler can be provided upon customer request.
The thrust and journal bearings are of the tilting pad type.

Starting System

In this package, the Electric Generator is provided with an LCI VFD starting panel that allows it to be used as the gas turbine starter. The panel allows the generator to act as a motor until the machine reaches the self-sustaining speed. At that point, the generator function is switched to generation mode to achieve synchronization as soon as a suitable rpm is reached.



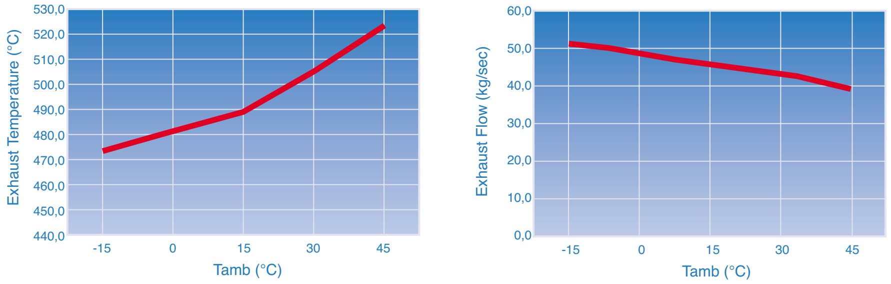
GE10 Gas Turbine SPECIFICATIONS

Axial Compressor	• 11-Stage Axial Flow • 15.5:1 Pressure Ratio
Combustion Chamber	• Single Can Combustor • Pollution prevention: DLN Gas Available DLN Dual Fuel Available
Turbine **GE10-1**	• 3-Stage HP Turbine 11000 rpm
Nominal Rating - ISO	At 15 °C, Sea Level, No External Pressure Losses, Relative Humidity 60%, Natural Gas Fuel with LHV = 32 to 44 MJ/Nm³

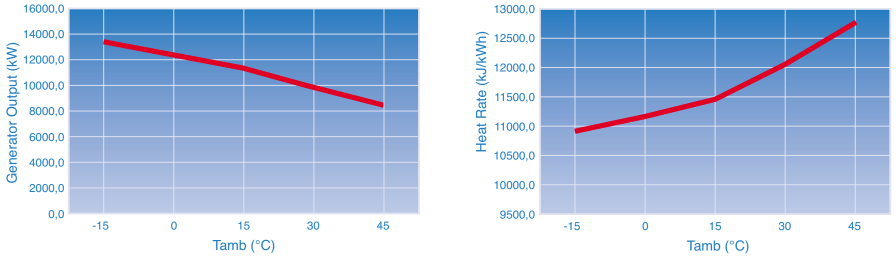
		GE10-1
ELECTRICAL OUTPUT (kW)	....	11250
ELECTRICAL EFFICIENCY (%)	....	31.4
EXHAUST FLOW (kg/sec)	....	47.5
EXHAUST TEMPERATURE (°C)	....	482

GE10 Gas Turbine Performance Curves

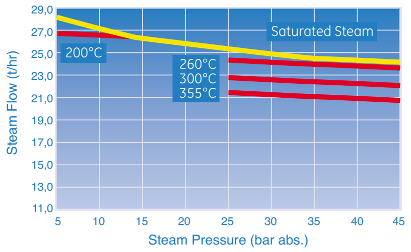
Effect of Compressor Inlet Temperature on Exhaust Temperature and Exhaust Flow Base Load with zero inlet and zero exhaust pressure drops at Sea Level, 60% RH - Natural Gas



Effect of Compressor Inlet Temperature on Output and Heat Rate Base Load with zero inlet and zero exhaust pressure drops at Sea Level, 60% RH - Natural Gas



Nominal Steam Production Capability in Cogeneration and Combined Cycle



Maintainability

GE10 maintenance can be carried out either "on-site" or at an authorized shop.

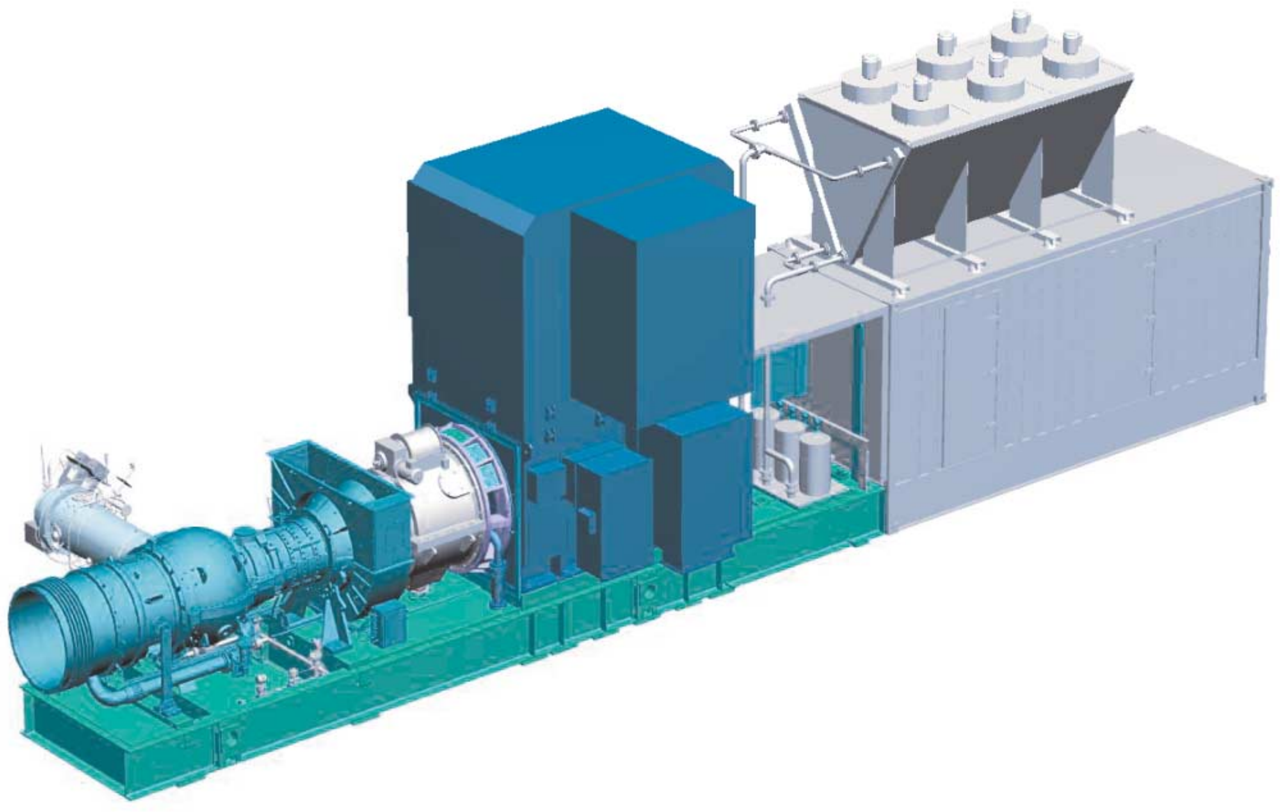
An engine exchange maintenance approach can be adopted to maximize the unit availability.

Enclosure doors, and flexible piping and electrical connectors permit the engine to be easily removed, and a back-up engine quickly installed to minimize the plant down time.

The engine is provided with borescope holes for periodic inspection of the internals, and the combustion chamber can be disassembled without removal of any of the engine casings. GE gives the highest priority to engineering and field assistance and offers continuous technological improvements, tailored solutions and support for each machine.

The Global Services Portfolio includes:

- Comprehensive training by highly qualified experts using a combination of traditional and modern interactive training materials and tools supplemented by our manufacturing, testing and repair facilities.
- Remote Monitoring and Diagnostics (RM&D) for accurate and continuous assessment of your equipment condition and for maintenance planning to maximize your plant output. It is equivalent to having a team of experts in your plant 24 hours a day 7 days a week.
- A Customer Care Center for a direct link to GE's Oil & Gas experts. Call any time to get technical support or information about products, offerings and orders.
- An Inventory of GE Oil & Gas capital parts available to satisfy emergency needs, including complete modules.
- Qualified GE regional service shops guaranteeing quality repairs and reducing turnaround time.
- Contractual Service Agreements to provide maintenance services at a predetermined cost and on a priority basis.



GE Energy

Acoustic Terms, Definitions and General Information

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GER-4248 (06/05)

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Acoustic Terms, Definitions and General Information

Foreword

The following document has been prepared for use during discussions and negotiation of common questions and issues regarding noise in Power Plant sales and applications. Expected readers include internal GE Sales and Engineering organizations not involved with the subject of noise on a regular basis.

Our intent is to present brief, easily understood definitions, explanations and examples of common terms and subjects, which may be encountered during communication with GE Customers and Partners.

Section I – Common Terms and Definitions is a compilation of terms which are commonly used in the Acoustic Design discipline, and a brief definition of each.

Section II – General Information presents basic definitions and terminology, as well as a brief discussion on the subject of noise contribution, reflection and reverberation, which are frequently subjects our Customers and Partners are not familiar with.

We hope that you find this document informative and helpful during discussions on the subject of Power Plant related noise.

Charles W. Powers

GE Energy

Section I – Terms and Definitions

Acoustic enclosure — A structure built around a machine to reduce noise.

Acoustic lagging — Materials applied externally to the surface of pipes and ducts to reduce noise penetration.

Acoustics — (1) The science of sound. (2) Of a room: those factors, which determine its character with respect to the quality of the received sound.

Airborne sound — Sound or noise radiated directly from a source, such as a loudspeaker or machine, into the surrounding air.

Ambient noise — Total noise level in a specified environment.

Attenuation — Term used to indicate reduction of noise or vibration, by whatever method necessary, usually expressed in decibels.

Audible frequency range — The range of the sound frequencies normally heard by the human ear. The audible range spans from 20 Hz to 20,000 Hz, but for most engineering investigations only frequencies between about 40 Hz and 11,000 Hz are considered.

Average Room Absorption Coefficient (α) — Total room absorption in Sabins or metric Sabins, divided by total room surface area in consistent units of square feet or square meters.

A-weighting — A frequency weighting that relates to the response of the human ear.

Background noise level — Prevailing noise level in a specified environment measured in the absence of the noise being studied.

Broad band noise — Spectrum consisting of a large number of frequency components, none of which is individually dominant.

Continuous equivalent noise level, L_{Aeq} — The steady noise level (usually in dBA) which, over the period of time under consideration, contains the same amount of sound energy as the time varying noise.

C-weighting — A frequency weighting closest to the linear or unweighted value.

dB (A) — The A-weighted sound pressure level.

Decibel (dB) — (1) Degree of loudness. (2) A unit for expressing the relative intensity of sounds on a scale from zero for the average least perceptible sound to about 130 for the average pain level.

Diffraction — The process whereby an acoustic wave is disturbed and its energy redistributed in space as a result of an obstacle in its path.

Direct sound — Sound that reaches a given location by direct, straight-line propagation from the sound source.

Directivity Index (DI) — The difference between sound pressure level in any direction in the acoustic far field and the average sound pressure level in that field.

F (fast) time weighting — (1) Averaging time used in sound level meters. (2) Fast setting has a time constant of 125 milliseconds and provides a fast reacting display response allowing the user to follow and measure not too rapidly fluctuating sound.

Far field — (1) Part of the sound field where the sound wave is spreading spherically. (2) Sound decays at 6 dB for a doubling of the distance from the sound source.

Field measurements — Measurements carried out on site.

Filter — A device that transmits signals within a certain band of frequencies but attenuates all others.

Free field conditions — An environment where there is no reflective surfaces.

Frequency — Repetition rate of a cycle, the number of cycles per second.

Impulse noise — A transient signal of short duration.

Insertion Loss (IL) —The reduction of noise level at a given location due to placement of a noise control device in the sound path between the sound source and that location. Usually rated in octave bands or 1/3-octave bands.

Intermittent noise — Noise that is not continuous.

L_{Amax} — The maximum A-weighted sound pressure level occurring in a specified time period.

L_{peak} — The maximum deviation of a signal from its mean value within a specified time interval.

L_1 — Sound pressure level that is exceeded one % of the time.

L_{10} — Sound pressure level that is exceeded 10% of the time.

$L_{10(1\ hr)}$ — Sound pressure level that is exceed 10% of the time in a period of 1 hour.

L_{90} — Level of noise that is exceeded 90% of the time.

L_{Aeq} — A steady noise level (weighted) which over a period of time has the same sound energy as the time varying noise.

Micro Pascal — One millionth of a Pascal.

Near field — (1) Area that surrounds the noise source. (2) Sound does not decay at 6 dB for a doubling of the distance from the sound source.

Noise — Unwanted sound.

Noise limit — A maximum value imposed on a noise level.

Noise Reduction (NR) — The difference in sound pressure level between any two points along the path of sound propagation.

Octave — The range between two frequencies whose ratio is 2:1.

Pascal — A unit of measure equal to 1 N/m^2

Peak — The maximum deviation of a signal from its mean value within a specified time interval.

Perceived noise level — The sound pressure level assessed by observers.

Pico watt — One-trillionth (10^{-12}) part of a watt.

Pure tone — A sound for which the waveform is a sine wave at a single frequency.

Reflection — Redirection of sound waves.

Refraction — Change in direction of sound waves caused by changes in the sound wave velocity.

Residual noise — Ambient noise remaining when specific noise is suppressed.

Reverberant sound/reverberation — The sound in an enclosed space, which results from, repeated reflections at the boundaries.

S (slow) time weighting — (1) Averaging times used in sound level meters. (2) Time constant of one [1] second that gives a slower response which helps average out the display fluctuations.

Sabin — Unit of acoustic sound absorption, equivalent to the absorption by one square meter of perfect absorber.

Silencer — A device used for reducing noise within air and gas flow systems.

Sound — Pressure fluctuations in air within the audible range.

Sound absorption — (1) The process by which sound energy is converted into heat, leading to the reduction in sound pressure level. (2) The sensation perceived by the sense of hearing.

Acoustic Terms, Definitions and General Information

Sound Absorption Coefficient (α) — The dimensionless ratio of sound energy absorbed by a given surface to that incident upon the surface.

Sound insulating material — Material designed and used as partitions in order to minimize the transmission of sound.

Sound insulation — The reduction or attenuation of sound by a solid partition between source and receiver. This may include a building wall, floor, barrier wall or acoustic enclosure.

Sound intensity — The sound flowing per unit area, in a given direction, measured over an area perpendicular to the direction of flow; units are W/m^2.

Sound level — A frequency-weighted sound pressure level, i.e., A-weighted value.

Sound level meter — Device used to measure sound pressure levels.

Sound power — The sound energy radiated per unit time by a sound source, measured in Watts (W).

Sound Power Level, L_w (PWL) — Sound power measured on a decibel scale.

Sound pressure — The fluctuations in air, measured in Pascals (PA).

Sound Pressure Level, L_p (SPL) — Sound pressure measured on a decibel scale.

Sound transmission — The transfer of sound energy through a barrier from one medium to another.

Sound Transmission Class (STC) — A single number decibel rating of the transmission loss properties of a partition.

Spectrum — A quantity expressed as a function of frequency, such as sound pressure versus frequency.

Structure borne noise — Generation and propagation of time-dependent motions and forces in solid materials, which result in unwanted, radiated sound.

Threshold of hearing — The lowest level of sound that can be heard by the human ear.

Transient — Sounds, which are audible for a limited period of time.

Transmission loss — Measure of the airborne sound insulating properties, in a particular frequency band, of a material.

Unweighted sound pressure level — A sound pressure level that has not been frequency weighted.

Vibration isolation — Reduction of force or displacement transmitted by a vibratory source.

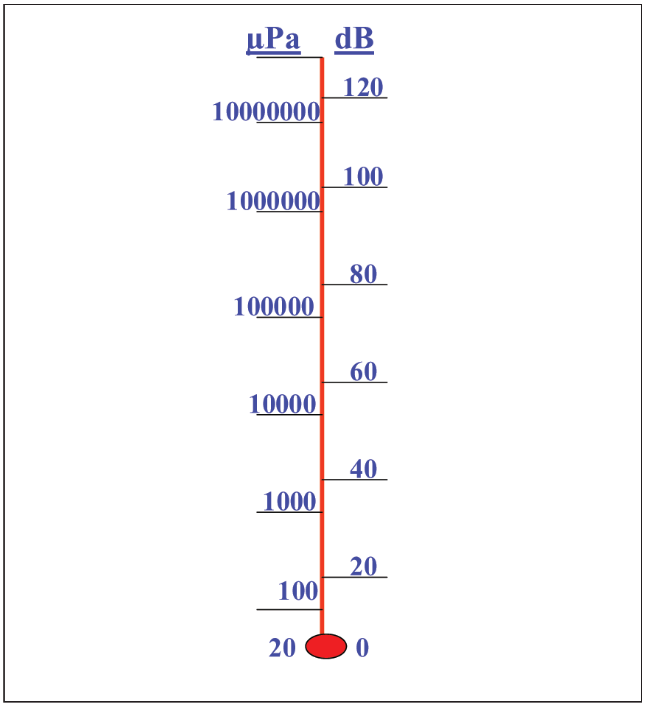
Watt (W) — The unit of power when 1 joule is expanded in one second.

White noise — A random broadband noise that contains equal power per unit bandwidth.

Section II – General Information

A. What is Sound?

Any pressure variation that the eardrum can detect.



B. Terminology

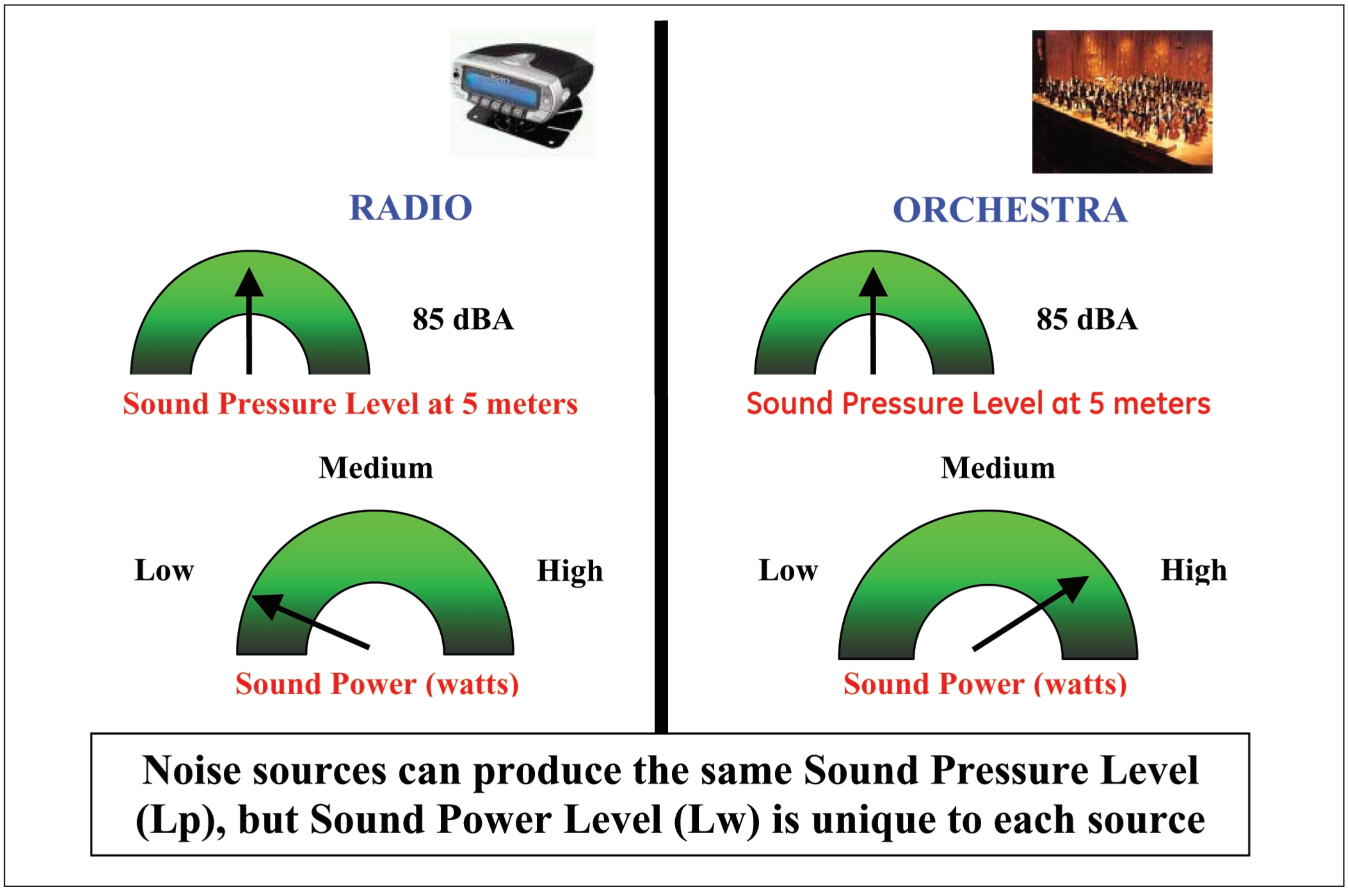
Decibel – dB

- Threshold of hearing – 20 m Pa
- Threshold of pain – 200,000,000 m Pa
- Ear does not respond linearly to sound level
- Logarithmic scale replicates the human ear better

Weighting – dB (Lin) & dB(A)

- Hearing sensitivity varies at different frequencies
- "A" Weighting simulates the frequency response of the Human Ear

C. Sound Pressure vs. Sound Power



Noise sources can produce the same Sound Pressure Level (Lp), but Sound Power Level (Lw) is unique to each source

Figure 1. Sound Pressure vs. Sound Power

D. Comparative Noise Sound Pressure Levels

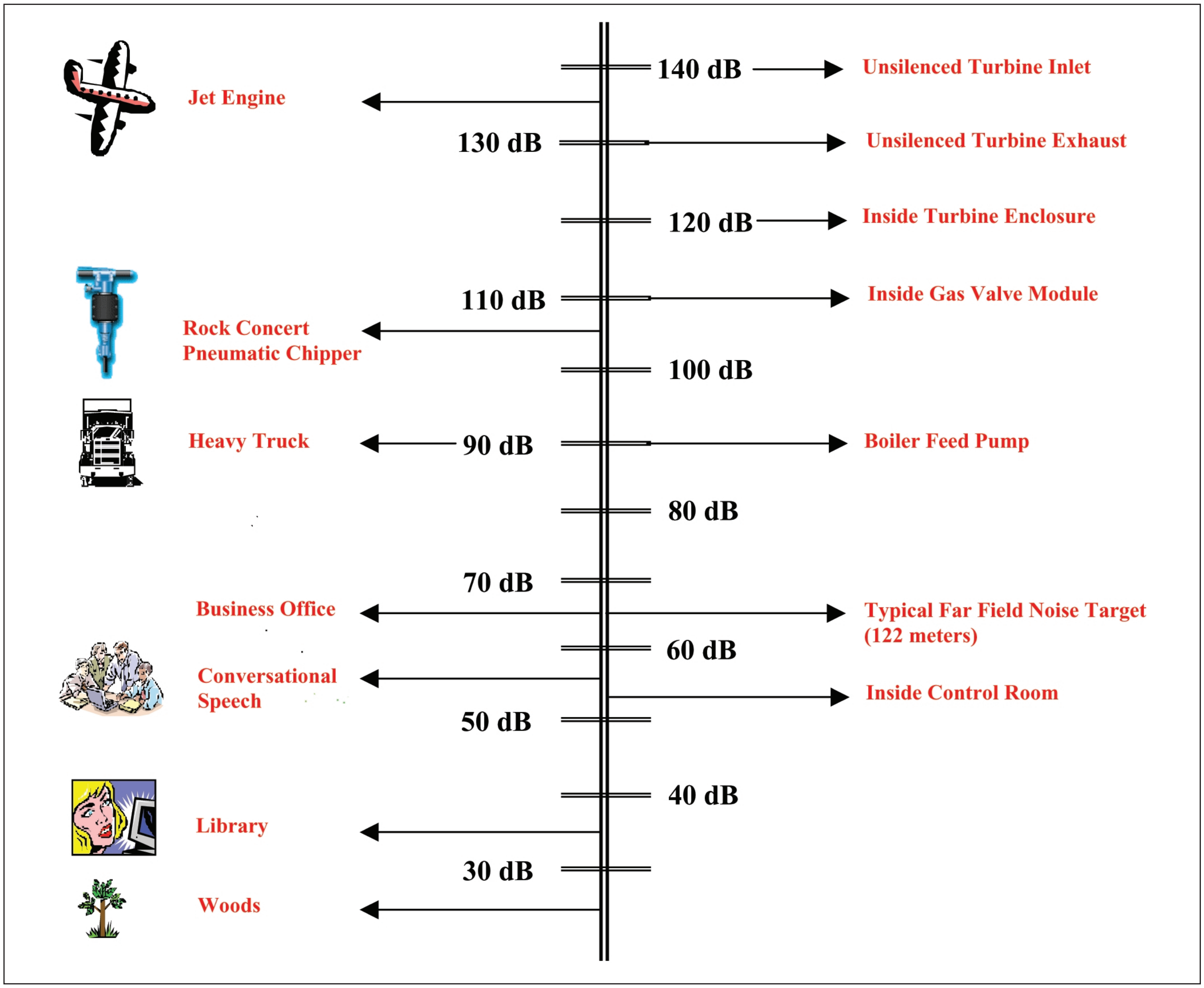


Figure 2. Comparative Noise Sound Pressure Levels

E. Power Plant Noise Levels

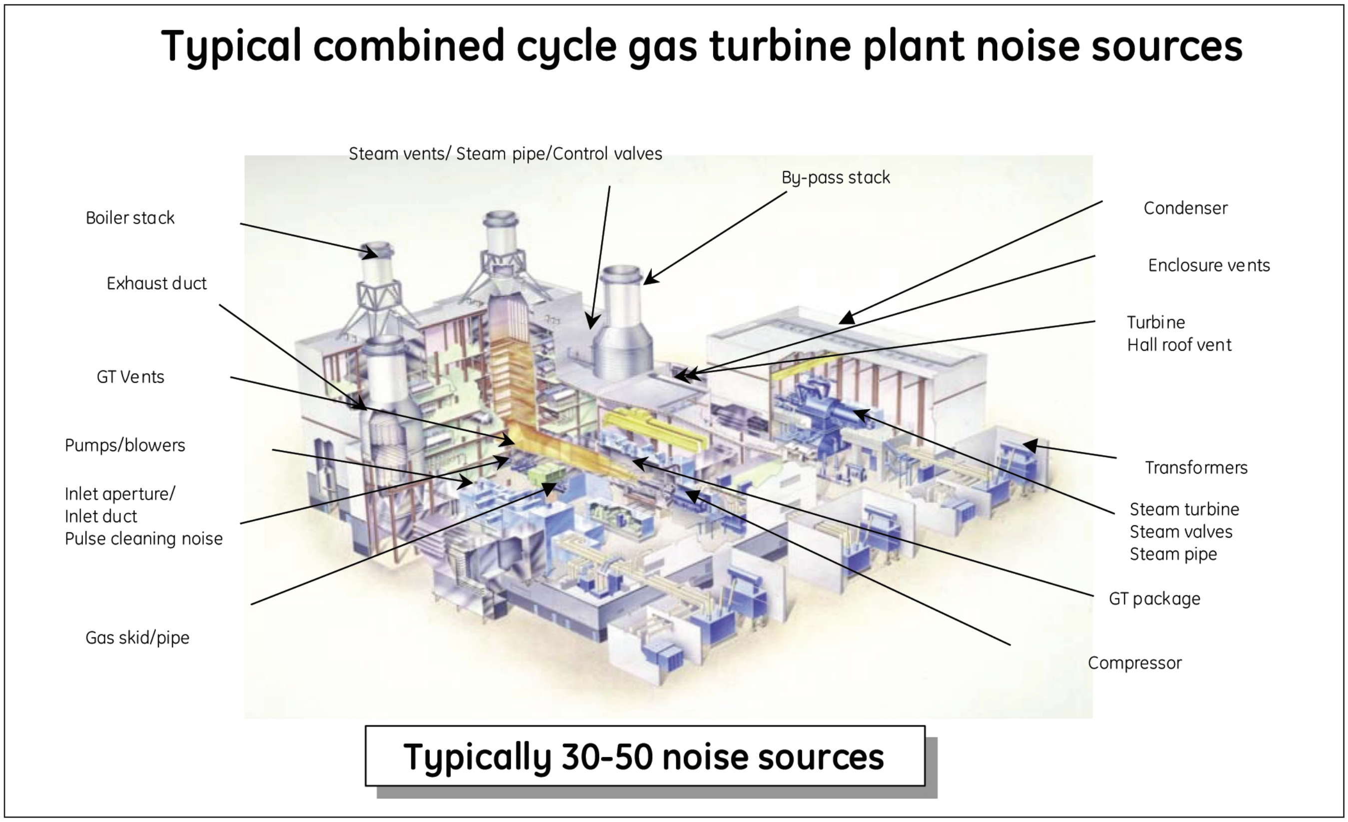


Figure 3. Power Plant Noise Levels

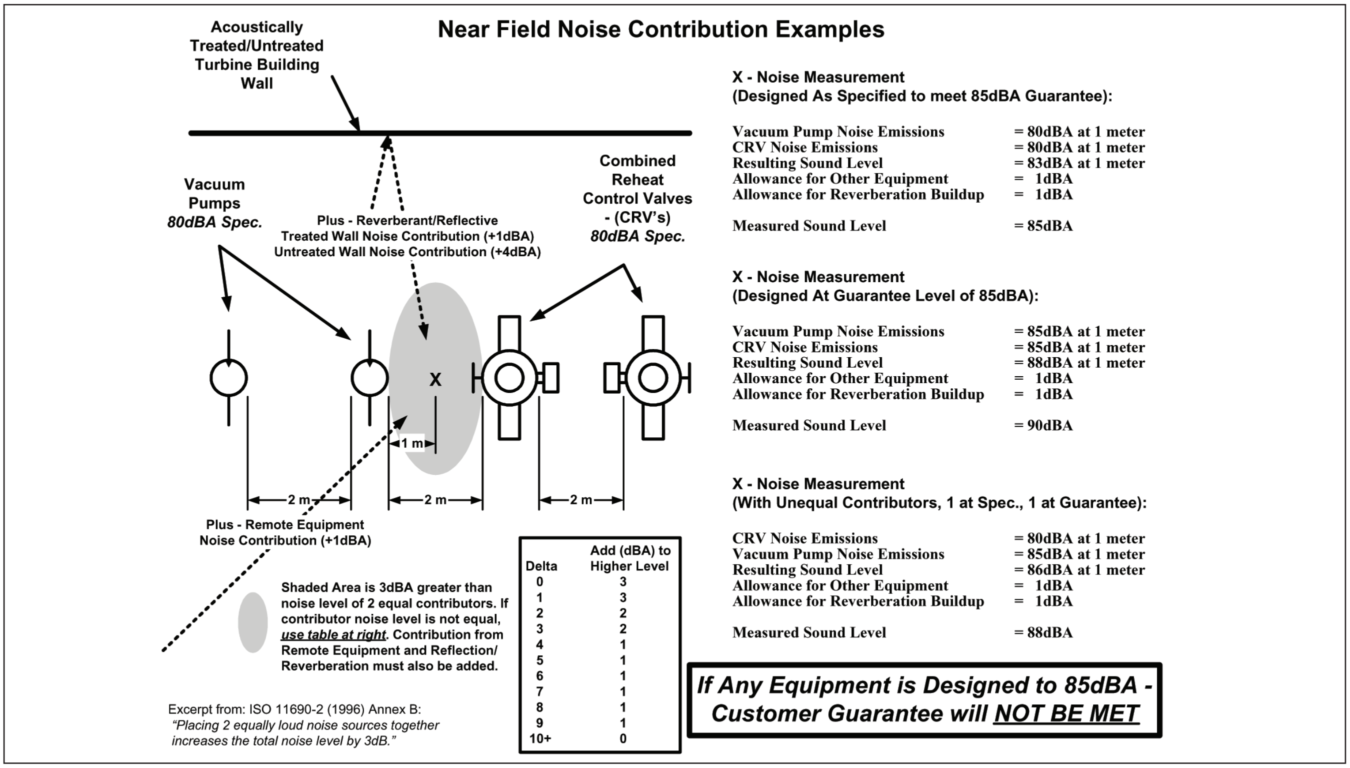
F. Noise Contribution, Reverberation and Reflection

The noise level at any location within a plant is the combined effect of noise radiated by all sources. Therefore, the noise from each individual source must be less than the overall plant requirement.

In addition, the containment of the sound energy within a building results in a reverberant buildup of noise. The noise reflected from the interior building walls and other surfaces causes an increase in the noise level.

For example: In order for the entire plant to satisfy a noise guarantee of 85 dBA Maximum it is necessary for each piece of equipment, including all of GE scope of supply equipment as well as the equipment supplied by others, to radiate less than 85 dBA.

As an example, if the vacuum pump is located 2 meters from the combustion turbine and radiates 80 dBA at 1 meter and the combustion turbine radiates 80 dBA at 1 meter, the resulting sound level is 83 dBA at a location 1 meter from both pieces of equipment (80 dBA + 80 dBA = 83 dBA). In addition, there will be noise from other equipment within the area. A 1 dBA allowance is included to account for the contribution from this other equipment. A 1 dBA allowance is also included to account for the reverberant buildup effect of noise within the building. Therefore, all equipment must be designed to a level of 80 dBA or less in order for sound levels within the building to meet the client’s requirement of 85 dBA at all locations. To minimize the impact of achieving these stringent noise requirements, no design margin should be included in these design values. The



X - Noise Measurement
(Designed As Specified to meet 85dBA Guarantee):

Vacuum Pump Noise Emissions	= 80dBA at 1 meter
CRV Noise Emissions	= 80dBA at 1 meter
Resulting Sound Level	= 83dBA at 1 meter
Allowance for Other Equipment	= 1dBA
Allowance for Reverberation Buildup	= 1dBA
Measured Sound Level	= 85dBA

X - Noise Measurement
(Designed At Guarantee Level of 85dBA):

Vacuum Pump Noise Emissions	= 85dBA at 1 meter
CRV Noise Emissions	= 85dBA at 1 meter
Resulting Sound Level	= 88dBA at 1 meter
Allowance for Other Equipment	= 1dBA
Allowance for Reverberation Buildup	= 1dBA
Measured Sound Level	= 90dBA

X - Noise Measurement
(With Unequal Contributors, 1 at Spec., 1 at Guarantee):

CRV Noise Emissions	= 80dBA at 1 meter
Vacuum Pump Noise Emissions	= 85dBA at 1 meter
Resulting Sound Level	= 86dBA at 1 meter
Allowance for Other Equipment	= 1dBA
Allowance for Reverberation Buildup	= 1dBA
Measured Sound Level	= 88dBA

Shaded Area is 3dBA greater than noise level of 2 equal contributors. If contributor noise level is not equal, *use table at right*. Contribution from Remote Equipment and Reflection/ Reverberation must also be added.

Delta	Add (dBA) to Higher Level
0	3
1	3
2	2
3	2
4	1
5	1
6	1
7	1
8	1
9	1
10+	0

Excerpt from: ISO 11690-2 (1996) Annex B:
"Placing 2 equally loud noise sources together increases the total noise level by 3dB."

If Any Equipment is Designed to 85dBA - Customer Guarantee will NOT BE MET

Figure 4. Near-Field Noise Contribution Examples

values specified are anticipated to achieve the required sound levels with no additional design margin. The GE-supplied equipment will be designed to the same stringent sound level requirements as the equipment supplied by others.

- Vacuum Pump Noise Emissions = 80 dBA at 1 meter
- Combustion Turbine Noise Emissions = 80 dBA at 1 meter
- Resulting Sound Level = 83 dBA at 1 meter
- Allowance for Other Neighboring Equipment = 1 dBA
- Allowance for Reverberation Buildup = 1 dBA
- Actual Sound Level Measured = 85 dBA

Section III — Applicable Reference Documents and Standards

GEK-110392, "Standard Noise Assessment Procedure."

GER-4221, "Power Generation Equipment and Other Factors Concerning the Protection of Power Plant Employees Against Noise in European Union Countries."

GER-4239, "Power Plant Near Field Noise Considerations."

ANSI/ASME PTC 36-1985, "Measurement of Industrial Sound."

ANSI B133.8-1977, "Gas Turbine Installation Sound Emissions."

ISO 3746, "Acoustics — Determination of sound power levels of noise sources using sound pressure — Survey method using an enveloping measurement surface over a reflecting plane."

ISO 6190, "Acoustics — Measurement of sound pressure levels of gas turbine installations for evaluating environmental noise — Survey method."

ANSI S1.1-1994, "American National Standard Acoustical Terminology."

ISO 10494-1993, "Gas turbine and gas turbine sets — Measurement of emitted airborne noise — Engineering/survey method."

GE Power Systems

Gas Turbine Emissions and Control

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Gas Turbine Emissions and Control

Contents

Gas Turbine Emissions and Control

Introduction

Worldwide interest in gas turbine emissions and the enactment of Federal and State regulations in the United States have resulted in numerous requests for information on gas turbine exhaust emission estimates and the effect of exhaust emission control methods on gas turbine performance. This paper provides nominal estimates of existing gas turbine exhaust emissions as well as emissions estimates for numerous gas turbine modifications and uprates. (For site-specific emissions values, customers should contact GE.) Additionally, the effects of emission control methods are provided for gas turbine cycle performance and recommended turbine inspection intervals. Emission control methods vary with both internal turbine and external exhaust system emission control. Only the internal gas turbine emission control methods — lean head end liners and water/steam injection — will be covered in this paper.

In the early 1970s when emission controls were originally introduced, the primary regulated gas turbine emission was NO_x. For the relatively low levels of NO_x reduction required in the 1970s, it was found that injection of water or steam into the combustion zone would produce the desired NO_x level reduction with minimal detrimental impact to the gas turbine cycle performance or parts lives. Additionally, at the lower NO_x reductions the other exhaust emissions generally were not adversely affected. Therefore GE has supplied NO_x water and steam injection systems for this application since 1973.

With the greater NO_x reduction requirements imposed during the 1980s, further reductions in NO_x by increased water or steam injection began to cause detrimental effects to the gas turbine cycle performance, parts lives and inspection criteria. Also, other exhaust emissions began to rise to measurable levels of concern. Based on these factors, alternative methods of emission controls have been developed:

- Internal gas turbine
  - —Multiple nozzle quiet combustors introduced in 1988
  - —Dry Low NO_x combustors introduced in 1990
- External
  - —Exhaust catalysts

This paper will summarize the current estimated emissions for existing gas turbines and the effects of available emission control techniques (liner design and water/steam injection) on gas turbine emissions, cycle performance, and maintenance inspection intervals. The latest technology includes Dry Low NO_x and catalytic combustion. These topics are covered in other GERs.

Emissions Characteristics of Conventional Combustion Systems

Typical exhaust emissions from a stationary gas turbine are listed in *Table 1*. There are two distinct categories. The major species (CO_2, N_2, H_2O, and O_2) are present in percent concentrations. The minor species (or pollutants) such as CO, UHC, NO_x, SO_x, and particulates are present in parts per million concentrations. In general, given the fuel composition and machine operating conditions, the major species compositions can be calculated. The minor species, with the exception of total sulfur oxides, cannot. Characterization of the pollutants requires careful measurement and semi-theoretical analysis.

The pollutants shown in *Table 1* are a function of gas turbine operating conditions and fuel composition. In the following sections, each pollutant will be considered as a function of

Major Species	Typical Concentration (% Volume)	Source
Nitrogen (N_2)	66 - 72	Inlet Air
Oxygen (O_2)	12 - 18	Inlet Air
Carbon Dioxide (CO_2)	1 - 5	Oxidation of Fuel Carbon
Water Vapor (H_2O)	1 - 5	Oxidation of Fuel Hydrogen

Minor Species Pollutants	Typical Concentration (PPMV)	Source
Nitric Oxide (NO)	20 - 220	Oxidation of Atmosphere Nitrogen
Nitrogen Dioxide (NO_2)	2 - 20	Oxidation of Fuel-Bound Organic Nitrogen
Carbon Monoxide (CO)	5 - 330	Incomplete Oxidation of Fuel Carbon
Sulfur Dioxide (SO_2)	Trace - 100	Oxidation of Fuel-Bound Organic Sulfur
Sulfur Trioxide (SO_3)	Trace - 4	Oxidation of Fuel-Bound Organic Sulfur
Unburned Hydrocarbons (UHC)	5 - 300	Incomplete Oxidation of Fuel or Intermediates
Particulate Matter Smoke	Trace - 25	Inlet Ingestion, Fuel Ash, Hot-Gas-Path Attrition, Incomplete Oxidation of Fuel or Intermediates

Table 1. Gas turbine exhaust emissions burning conventional fuels

operating conditions under the broad divisions of gaseous and liquid fuels.

Nitrogen Oxides

Nitrogen oxides ($NO_x = NO + NO_2$) must be divided into two classes according to their mechanism of formation. Nitrogen oxides formed from the oxidation of the free nitrogen in the combustion air or fuel are called "thermal NO_x." They are mainly a function of the stoichiometric adiabatic flame temperature of the fuel, which is the temperature reached by burning a theoretically correct mixture of fuel and air in an insulated vessel.

The following is the relationship between combustor operating conditions and thermal NO_x production:

- NO_x increases strongly with fuel-to-air ratio or with firing temperature
- NO_x increases exponentially with combustor inlet air temperature
- NO_x increases with the square root of the combustor inlet pressure
- NO_x increases with increasing residence time in the flame zone
- NO_x decreases exponentially with increasing water or steam injection or increasing specific humidity

Emissions which are due to oxidation of organically bound nitrogen in the fuel—fuel-bound nitrogen (FBN)—are called "organic NO_x." Only a few parts per million of the available free nitrogen (almost all from air) are oxidized to form nitrogen oxide, but the oxidation of FBN to NO_x is very efficient. For conventional GE combustion systems, the efficiency of conversion of FBN into nitrogen oxide is 100% at low FBN contents. At higher levels of FBN, the conversion efficiency decreases.

Organic NO_x formation is less well understood than thermal NO_x formation. It is important to note that the reduction of flame temperatures to abate thermal NO_x has little effect on organic NO_x. For liquid fuels, water and steam injection actually increases organic NO_x yields. Organic NO_x formation is also affected by turbine firing temperature. The contribution of organic NO_x is important only for fuels that contain significant amounts of FBN such as crude or residual oils. Emissions from these fuels are handled on a case-by-case basis.

Gaseous fuels are generally classified according to their volumetric heating value. This value is useful in computing flow rates needed for a given heat input, as well as sizing fuel nozzles, combustion chambers, and the like. However, the stoichiometric adiabatic flame temperature is a more important parameter for characterizing NO_x emission. *Table 2* shows relative thermal NO_x production for the same combustor burning different types of fuel. This table shows the NO_x relative to the methane NO_x based on adiabatic stoichiometric flame temperature. The gas turbine is controlled to approximate constant firing temperature and the products of combustion for different fuels affect the reported NO_x correction factors. Therefore, *Table 2* also shows columns for relative NO_x values calculated for different fuels for the same combustor and constant firing temperature relative to the NO_x for methane.

Typical NO_x performance of the MS7001EA, MS6001B, MS5001P, and MS5001R gas turbines burning natural gas fuel and No. 2 distillate is shown in *Figures 1–4* respectively as a function of firing temperature. The levels of emissions for No. 2 distillate oil are a very nearly constant fraction of those for natural gas over the operating range of turbine inlet temperatures. For any given model of GE heavy-duty gas turbine, NO_x correlates very well with firing temperature.

Low-Btu gases generally have flame temperatures below 3500°F/1927°C and correspondingly lower thermal NO_x production. However, depending upon the fuel-gas clean-up train, these gases may contain significant quantities of ammonia. This ammonia acts as FBN and will be oxidized to NO_x in a conventional diffusion combustion system. NO_x control measures such as water injection or steam injection will have little or no effect on these organic NO_x emissions.

Carbon Monoxide

Carbon monoxide (CO) emissions from a conventional GE gas turbine combustion system are less than 10 ppmvd (parts per million by volume dry) at all but very low loads for steady-state operation. During ignition and acceleration, there may be transient emission levels higher than those presented here. Because of the very short loading sequence of gas turbines, these levels make a negligible contribution to the integrated emissions. *Figure 5* shows typical

Fuel	Stoichiometric Flame Temp.	NO_x (ppmvd/ppmvw-Methane) 1765°F/963°C – 2020°F/1104°C Firing Time	NO_x (ppmvd/ppmvw-Methane) @ 15% O_2, 1765°F/963°C – 2020°F/1104°C Firing Time
Methane	1.000	1.000/1.000	1.000/1.000
Propane	1.300	1.555/1.606	1.569/1.632
Butane	1.280	1.608/1.661	1.621/1.686
Hydrogen	2.067	3.966/4.029	5.237/5.299
Carbon Monoxide	2.067	3.835/3.928	4.128/0.529
Methanol	0.417-0.617	0.489/0.501	0.516/0.529
No. 2 Oil	1.667	1.567/1.647	1.524/1.614

Table 2. Relative thermal NO_x emissions

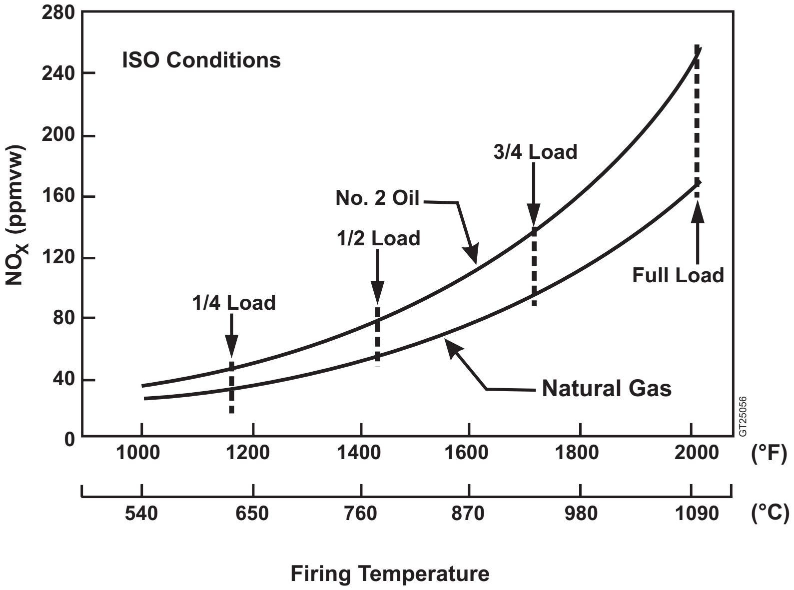

Figure 1. MS7001EA NO_x emissions

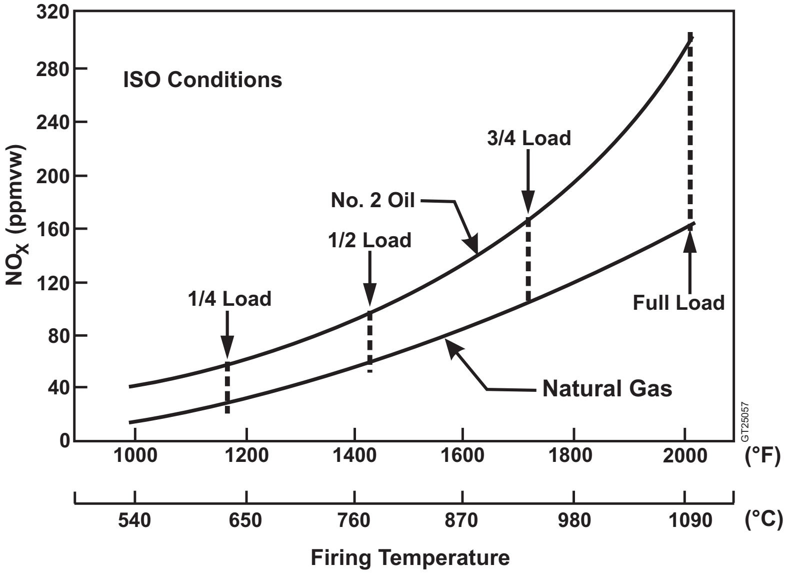

Figure 2. MS6001B NO_x emissions

CO emissions from a MS7001EA, plotted versus firing temperature. As firing temperature is reduced below about 1500°F/816°C the carbon monoxide emissions increase quickly. This characteristic curve is typical of all heavy-duty machine series.

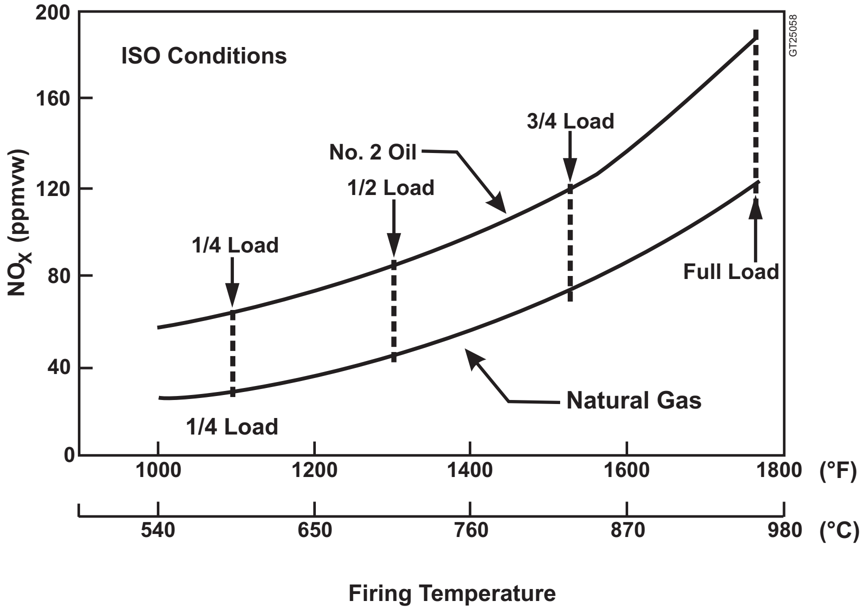

Figure 3. MS5001P A/T NO_x emissions

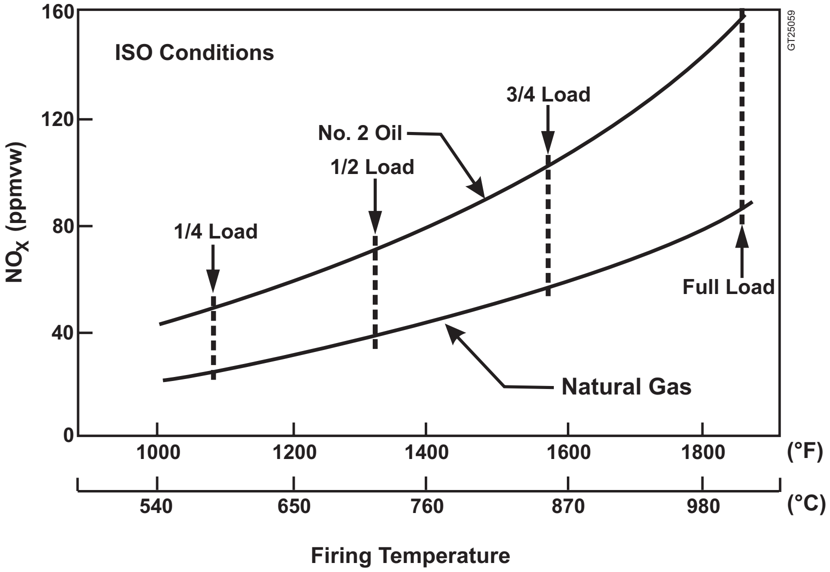

Figure 4. MS5001R A/T NO_x emissions

Unburned Hydrocarbons

Unburned hydrocarbons (UHC), like carbon monoxide, are associated with combustion inefficiency. When plotted versus firing temperature, the emissions from heavy-duty gas turbine combustors show the same type of hyperbolic curve as carbon monoxide. (*See Figure 6.*) At all but very low loads, the UHC emission levels for No. 2 distillate and natural gas are less than 7 ppmvw (parts per million by volume wet).

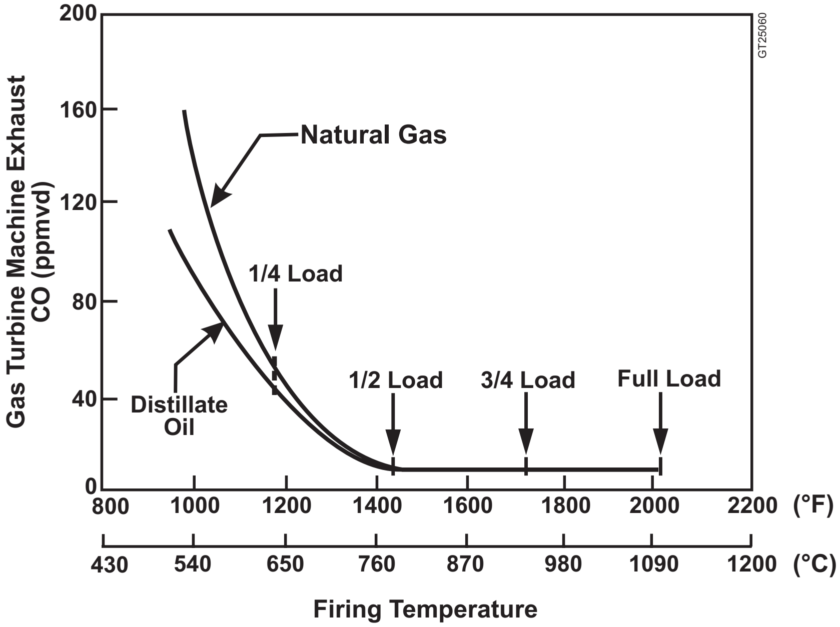

Figure 5. CO emissions for MS7001EA

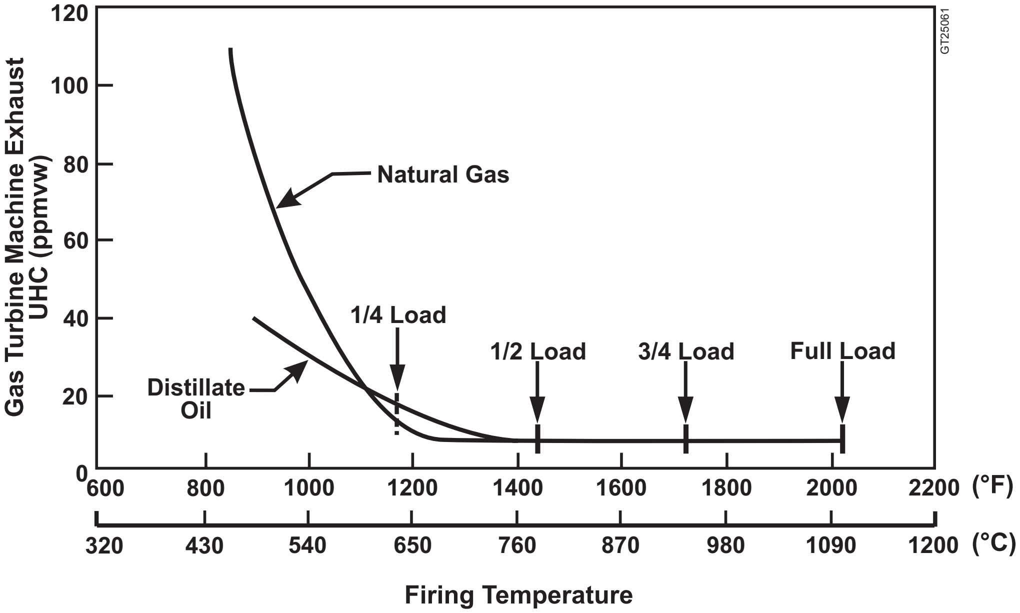

Figure 6. UHC emissions for MS7001EA

Sulfur Oxides

The gas turbine itself does not generate sulfur, which leads to sulfur oxides emissions. All sulfur emissions in the gas turbine exhaust are caused by the combustion of sulfur introduced into the turbine by the fuel, air, or injected steam or water. However, since most ambient air and injected water or steam has little or no sulfur, the most common source of sulfur in the gas turbine is through the fuel. Due to the latest hot gas path coatings, the gas turbine will readily burn sulfur contained in the fuel with little or no adverse effects as long as there are no alkali metals present in the hot gas.

GE experience has shown that the sulfur in the fuel is completely converted to sulfur oxides. A nominal estimate of the sulfur oxides emissions is calculated by assuming that all fuel sulfur is converted to SO_2. However, sulfur oxide emissions are in the form of both SO_2 and SO_3. Measurements show that the ratio of SO_3 to SO_2 varies. For emissions reporting, GE reports that 95% of the sulfur into the turbine is converted to SO_2 in the exhaust. The remaining sulfur is converted into SO_3. SO_3 combines with water vapor in the exhaust to form sulfuric acid. This is of concern in most heat recovery applications where the stack exhaust temperature may be reduced to the acid dew point temperature. Additionally, it is estimated that 10% by weight of the SO_x generated is sulfur mist. By using the relationships above, the various sulfur oxide emissions can be easily calculated from the fuel flow rate and the fuel sulfur content as shown in *Figure 7.*

There is currently no internal gas turbine technique available to prevent or control the sulfur oxides emissions from the gas turbine. Control of sulfur oxides emissions has typically required limiting the sulfur content of the fuel, either by lower sulfur fuel selection or fuel blending with low sulfur fuel.

Particulates

Gas turbine exhaust particulate emission rates are influenced by the design of the combustion system, fuel properties and combustor operating conditions. The principal components of the particulates are smoke, ash, ambient noncombustibles, and erosion and corrosion products. Two additional components that could be considered particulate matter in some localities are sulfuric acid and unburned hydrocarbons that are liquid at standard conditions.

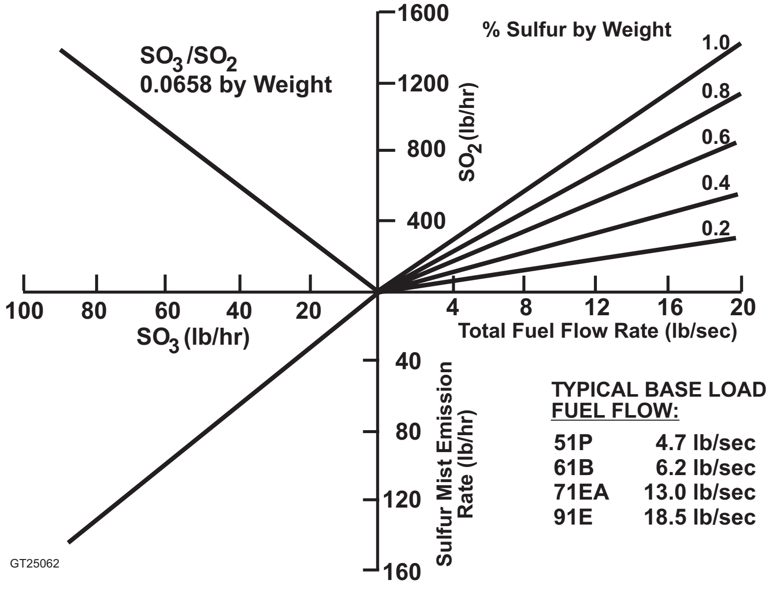

Figure 7. Calculated sulfur oxide and sulfur emissions

Smoke

Smoke is the visible portion of filterable particulate material. The GE combustor design coupled with air atomization of liquid fuels has resulted in a nonvisible plume over the gas turbine load range for a wide variety of fuels. The GE smoke-measuring unit is the Von Brand Reflective Smoke Number (GEVBRSN). If this number is greater than 93 to 95 for the MS7001E, then the plume will not be visible. For liquid fuels, the GEVBRSN is a function of the hydrogen content of the fuel. For natural gas fuel, the smoke number is essentially 99 to 100 over the load range and visible smoke is not present.

Dry Emissions Estimates at Base Load

The ISO non-abated full load emissions estimates for the various GE heavy-duty gas turbine models are provided in *Table 3*. The natural gas and #2 distillate fuel emission estimates shown are for thermal NO_x, CO, UHC, VOC, and particulates. For reporting purposes, all particulates are also reported as PM-10. Therefore PM-10 is not shown in the tables. The nominal full rated firing temperature for each gas turbine model is also shown in *Table 3*.

As can be easily seen in the table, at base load without NO_x abatement, the emissions of CO, UHC, VOC, and particulates are quite low. The estimated values of NO_x vary between gas turbine designs and generally increase with the frame size firing temperature.

Dry Emissions Estimates at Part Load

Simple-Cycle Turbines

At turbine outputs below base load the emissions change from the values given in *Table 3*. These changes are affected by the turbine configuration and application and in some cases by the turbine controls.

Single-shaft gas turbines with non-modulating inlet guide vanes operating at constant shaft speed have part load emissions characteristics which are easily estimated. For these turbines

Single Shaft Units Model	Firing Temp. F/C	Dry (Non-Abated)		H_2O/Steam Inj.	
		Gas	Dist.	Gas (FG1A/FG1B)	Gas (FG1C/FG1F)
MS5001P	1730/943	128	195	25	42
MS5001P-N/T	1765/963	142	211	25	42
MS6001B	2020/1104	161	279	25	65/42
MS7001B	1840/1004	109	165	25	42
MS7001B Option 3	1965/1074	124	191	25	42
MS7001B Option 4	2020/1104	132	205	25	42
MS7001EA	2020/1104	160	245	25	42
MS9001B	1940/1060	109	165	42	65
MS9001B Option 3	1965/1074	124	191	42	65
MS9001B Option 4	2020/1104	132	205	42	65
MS9001E	2020/1104	157	235	42	65
MS9001E	2055/1124	162	241	42	65
6FA	2350/1288				
7FA	2400/1316				
7FA	2420/1327				
9FA	2350/1288				
Two Shaft Units* Model	**Firing Temp. F/C**	**Dry (Non-Abated)**		**H_2O/Steam Inj.**	
		S.C.	**R.C.****	**S.C.**	**S.C.**
MS3002F	1575/1625/857/885	115	201	42	50
MS3002J	1730/943	128	217	42	50
MS3002J-N/T	1770/968	140	236	42	50
MS5002	1700/927	125	220	42	50
MS5002B-N/T	1770/966	137	255	42	50

* S.C. = Simple Cycle and R.C. = Regenerative Cycle
** Two-Shaft NOx Levels Are All on Gas Fuel

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Table 3. NO_x emission levels @ 15% O_2 (ppmvd)

the NO_x emissions vary exponentially with firing temperature as shown previously in *Figures 1–4*. The load points for each turbine are also marked on these figures. Due to the conversions used in the various NO_x reporting methods, the information in *Figures 1–4* has been redrawn in *Figures 8–11*. This information shows the estimated ISO NO_x emissions on a ppmvd @ 15% O_2, ppmvw, and lb/hour basis for MS7001EA, MS6001B, MS5001P and MS5001R. In these figures, the nominal peak load firing temperature point is also given. It should be noted that in some cases the NO_x ppmvd@15% O_2 reporting method can cause number values to increase as load is reduced (e.g., see the MS5001P A/T in *Figure 10*.) Since the GE MS9001E gas turbine is a scaled version of the MS7001E gas turbine, the MS7001E gas turbine figures can be used as an estimate of MS9001E gas turbine part load emissions characteristics.

Many gas turbines have variable inlet guide vanes that are modulated closed at part load conditions in order to maintain higher exhaust temperatures for waste heat recovery equipment located in the gas turbine exhaust. As shown in *Figure 12*, closing the inlet guide vanes has a slight effect on the gas turbine NO_x emissions. *Figure 12* shows the effect on NO_x ppmvd @ 15% O_2 and *Figure 13* shows the effect on NO_x lb/hr. The figures show both MS5001P and MS7001E characteristics. They also show normalized NO_x (% of base load value) vs. % base load. Curves are shown for load reductions by either closing the inlet guide vanes while maintaining exhaust temperature control and for load reductions by reducing firing temperature while keeping the inlet guide vanes fully open.

Mechanical drive gas turbines typically vary the output load shaft speed in order to adjust the turbine output to match the load equipment characteristic. Single-shaft gas turbines operating on exhaust temperature control have a maximum output NO_x emissions characteristic vs. turbine shaft speed, as shown in *Figure 14* for an MS5001R Advanced Technology uprated tur-

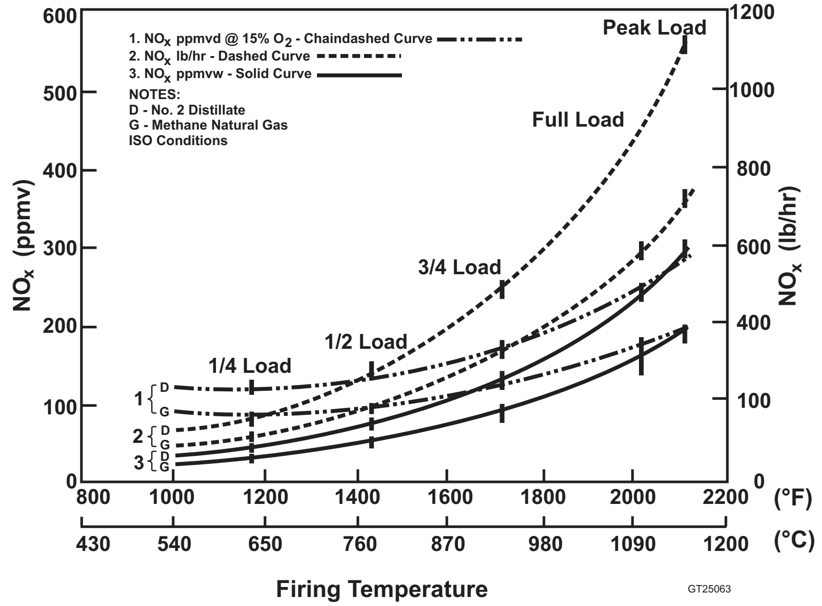

Figure 8. MS7001EA NO_x emissions

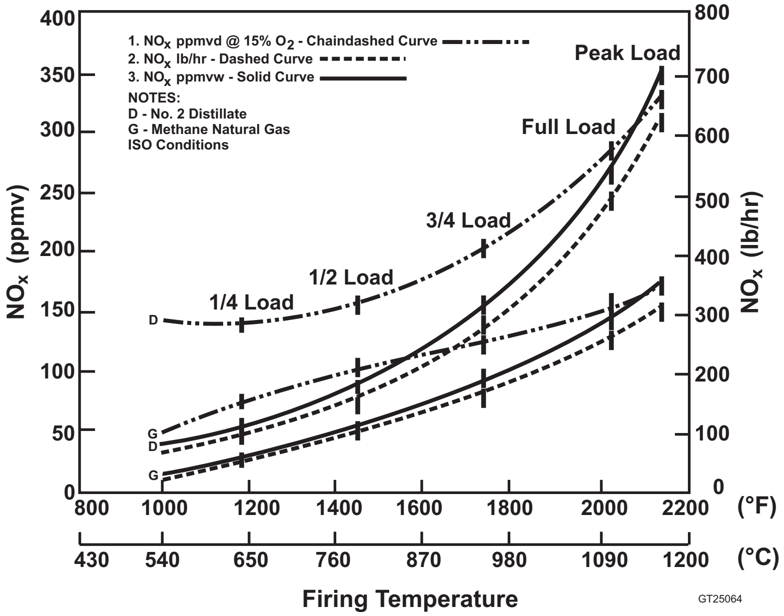

Figure 9. MS6001B NO_x emissions

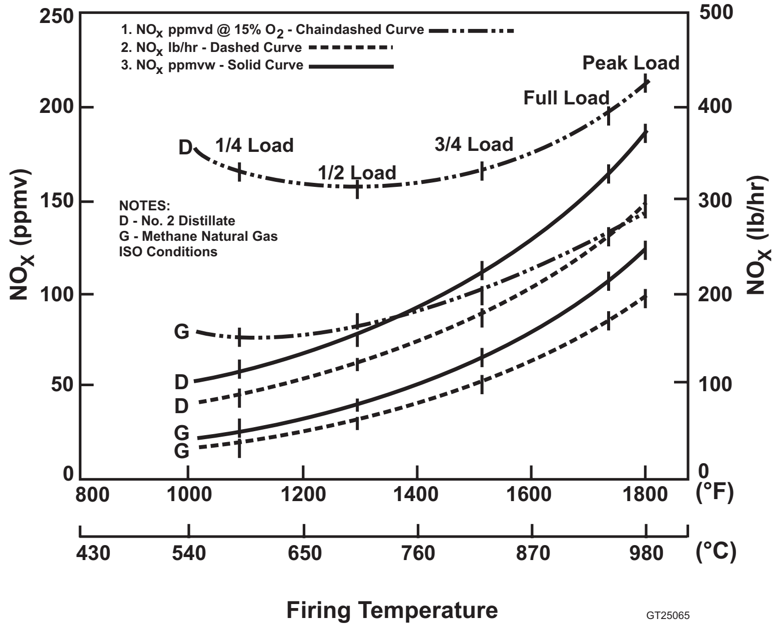

Figure 10. MS5001P A/T NO_x emissions

bine. The characteristic shown is primarily due to the gas turbine exhaust temperature control system and the turbine thermodynamics. As seen in *Figure 14*, as the turbine output shaft speed is reduced below 100%, NO_x emissions decrease directly with turbine shaft speed. As the speed decreases, the exhaust temperature increases till the exhaust component tempera-

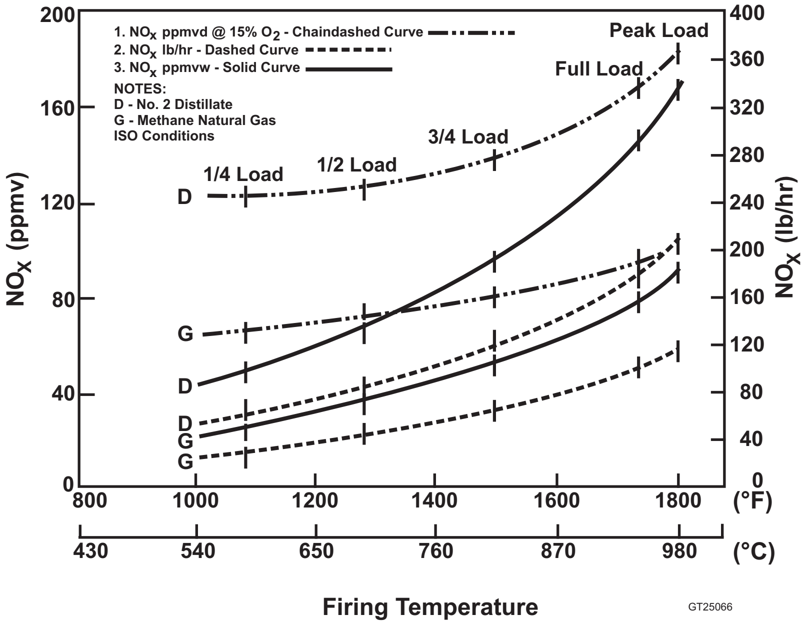

Figure 11. MS5001R A/T NO_x emissions

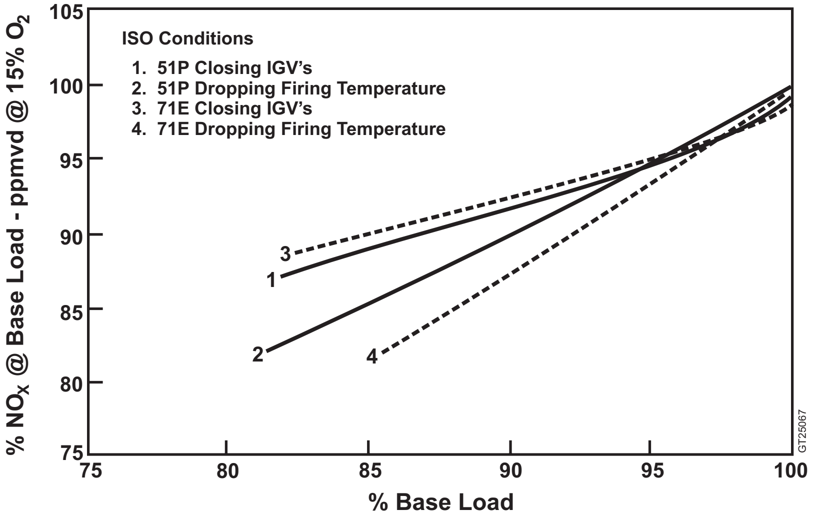

Figure 12. Inlet guide vane effect on NO_x ppmvd @ 15% O_2 vs. load

ture limit is reached. Once the exhaust isothermal limit is reached, the variation of NO_x emissions with speed will become greater. In *Figure 16* this exhaust isothermal temperature limit is reached at approximately 84% speed. Two-shaft gas turbines also vary the output turbine shaft speed with load conditions. However the gas turbine compressor shaft and combustor operating conditions are controlled independent of the output shaft speed. On a two-shaft gas turbine, if the gas turbine compressor shaft speed is held constant by the control system while on exhaust

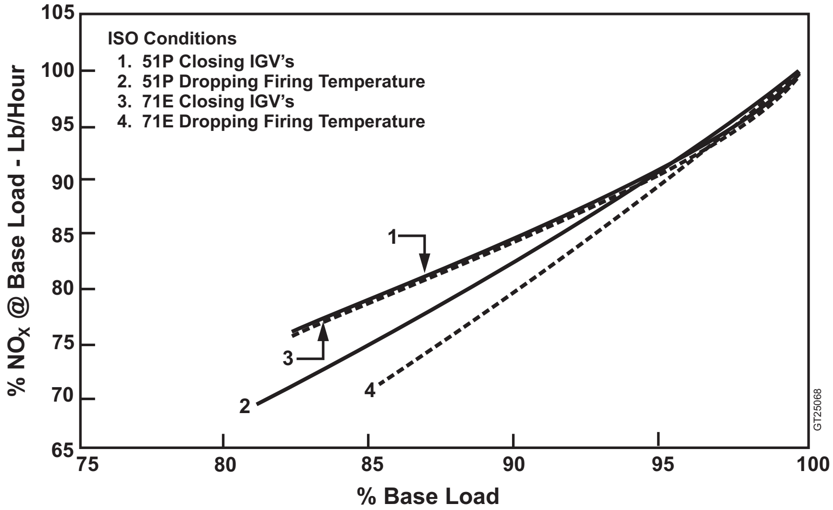

Figure 13. Inlet guide vane effect on NO_x lb/hour vs. load

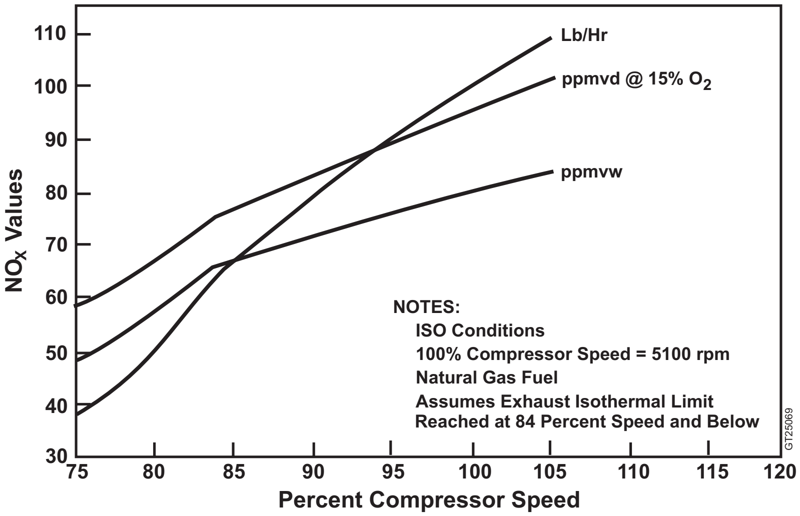

Figure 14. MS5001R A/T NO_x emissions vs. shaft speed

temperature control, the NO_x emissions are not affected by the load turbine shaft speed.

Exhaust Heat Recovery Turbines

Regenerative cycle and waste heat recovery two-shaft gas turbines are normally controlled to operate the gas turbine compressor at the minimum speed allowable for the desired load output. As load is increased from minimum, the gas turbine compressor speed is held at minimum until the turbine exhaust temperature reaches the temperature control curve. With further increase in load, the control system will increase the gas turbine compressor speed while following the exhaust temperature control curve. If the turbine has modulated inlet guide vanes, the inlet guide vanes will open first when the exhaust temperature control curve is reached, and then, once the inlet guide vanes are fully open, the gas turbine compressor speed will be increased.

Figure 15 shows the NO_x characteristic of a regenerative cycle MS3002J gas turbine at ISO conditions. Initially, as load is increased, NO_x increases with firing temperature while the gas turbine compressor is operating at minimum speed. For the turbine shown, the exhaust isothermal temperature control is reached at approximately 48% load. The gas turbine compressor shaft speed is then increased by the control system for further increases in load up to the 100% load point. At approximately 96% load, the gas turbine exhaust temperature control curve begins to limit exhaust temperature below the isothermal exhaust temperature due to the increasing airflow through the turbine and the NO_x values are reduced by the characteristic shown.

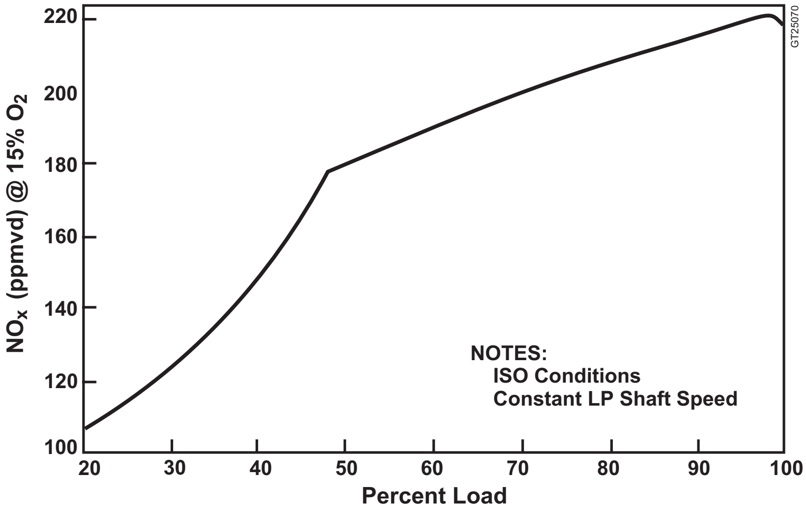

Figure 15. MS3002J regenerative NO_x vs. load

For a typical regenerative cycle MS5002B Advanced Technology gas turbine with modulated inlet guide vanes, the curve of NO_x vs. load at ISO conditions is shown in *Figure 16*. The NO_x vs. load characteristic is similar to the MS3002J. However, this design turbine will operate at low load with the inlet guide vanes partially closed and at minimum operating gas turbine compressor shaft speed. During initial loading, NO_x increases with firing temperature. When the exhaust temperature control system isothermal temperature limit is reached the inlet guide vanes are modulated open as load is increased. At approximately 90% load the gas turbine exhaust temperature control curve begins to limit exhaust temperature below the isothermal exhaust temperature due to the increasing airflow through the turbine and the NO_x values are reduced. At approximately 91.5% load for this turbine calculation, the inlet guide vanes are fully open and further increases in load are accomplished by increasing the gas turbine compressor speed resulting in the NO_x reduction as shown.

Other NO_x Influences

The previous sections of this paper consider the internal gas turbine design factors which influ-

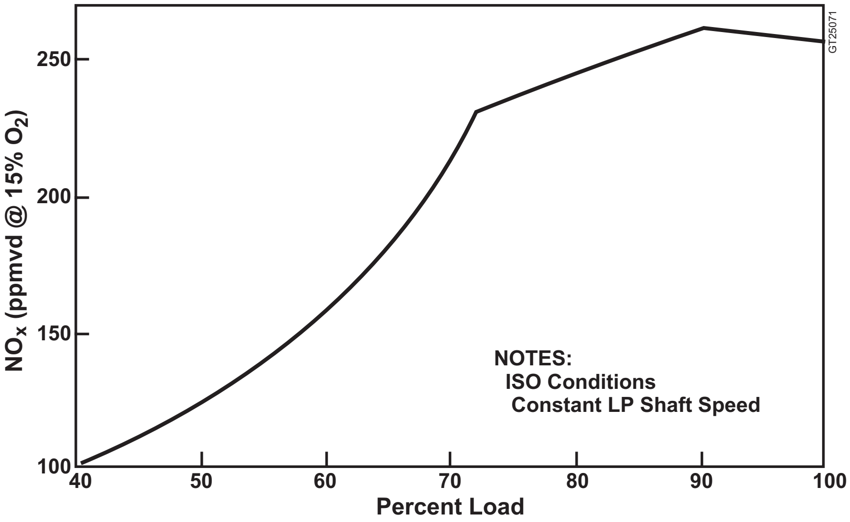

Figure 16. MS5002B A/T regenerative NO_x vs. load

ence emissions generation. There are many external factors to the gas turbine which impact the formation of NO_x emissions in the gas turbine cycle. Some of these factors will be discussed below. In all figures under this topic, the NO_x is presented as a percentage value where 100% represents the thermal ISO NO_x value for the turbine operating on base temperature control. For all figures except for the regenerator changes discussed, the curves drawn represent a single "best fit" line through the calculated characteristics for frame 3, 5, 6, 7, and 9 gas turbines. However, the characteristics shape that is shown is the same for all turbines.

Ambient Pressure. NO_x ppm emissions vary almost directly with ambient pressure. *Figure 17* provides an approximation for the ambient pressure effect on NO_x production on a lb/hr basis and on a ppmvd @ 15% O_2 basis. This figure is at constant 60% relative humidity. It should be noted that specific humidity varies with ambient pressure and that this variation is also included in the *Figure 18* curves.

Ambient Temperature. Typical NO_x emissions variation with ambient temperature is shown in *Figure 18*. This figure is drawn at constant ambient pressure and 60% relative humidity with the gas turbine operating constant gas turbine firing temperature. For an operating gas turbine the actual NO_x characteristic is directly influenced by the control system exhaust temperature control curve, which can change the slope of the curves. The typical exhaust temperature control curve used by GE is designed to hold constant turbine firing temperature in the 59°F/15°C to 90°F/32°C ambient temperature range. The firing temperature with this typical curve causes under-firing of approximately 20°F/11°C at 0°F/–18°C ambient, and approximately 10°F/6°C under-firing at 120°F/49°C ambient. Factors such as load limits, shaft output limits, and exhaust system temperature limits are also not included in the *Figure 18* curves. Based on the actual turbine exhaust temperature control curve used and other potential limitations that reduce firing temperature, the estimated NO_x emissions for an operating gas turbine are typically less than the values shown in *Figure 18* at both high and low ambients.

Relative Humidity. This parameter has a very

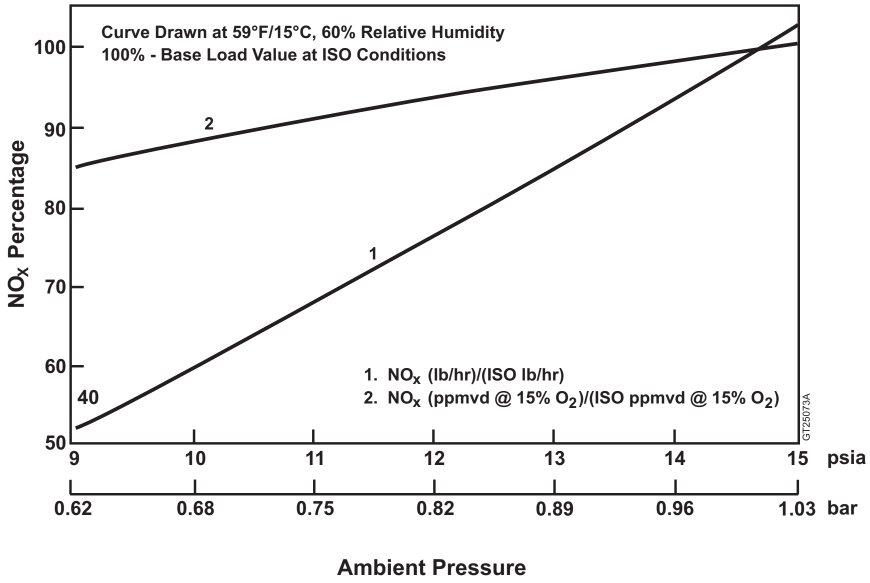

Figure 17. Ambient pressure effect on NO_X Frames 5, 6 and 7

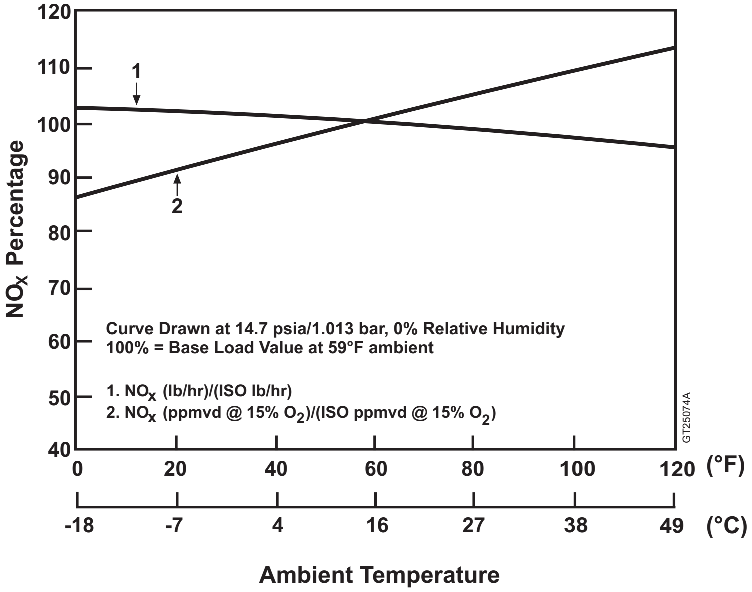

Figure 18. Ambient temperature effect on NO_X Frames 5, 6 and 7
0% Relative Humidity

strong impact on NO_x. The ambient relative humidity effect on NO_x production at constant ambient pressure of 14.7 psia and ambient temperatures of 59°F/15°C and 90°F/32°C is shown in *Figure 19*.

The impact of other parameters such as inlet/exhaust pressure drops, regenerator characteristics, evaporative/inlet coolers, etc., are similar to the ambient parameter effects described above. Since these parameters are

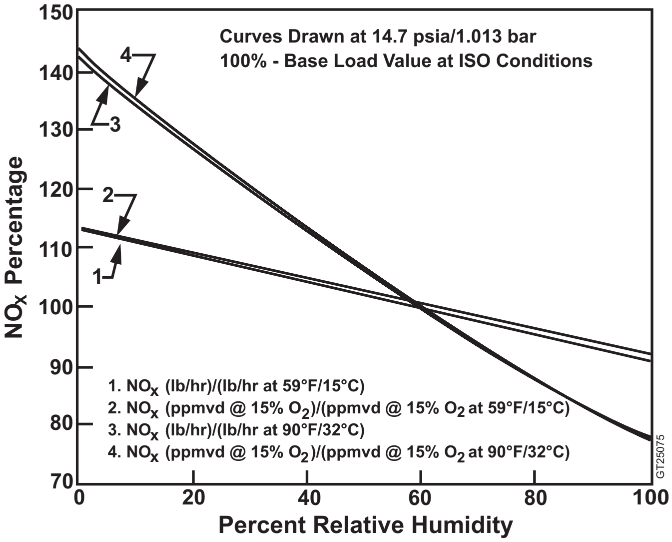

Figure 19. Relative humidity effect on NO_x Frames 5, 6 and 7

usually unit specific, customers should contact GE for further information.

Power Augmentation Steam Injection. The effect of power augmentation steam injection on gas turbine NO_x emissions is similar to NO_x steam injection on a ppmvw and lb/hr basis. However, only approximately 30% of the power augmentation steam injected participates in NO_x reduction. The remaining steam flows through dilution holes downstream of the NO_x producing area of the combustor. 100% of the power augmentation steam injected is used in the conversion from ppmvw to ppmvd @ 15% O_2.

Emission Reduction Techniques

The gas turbine, generally, is a low emitter of exhaust pollutants because the fuel is burned with ample excess air to ensure complete combustion at all but the minimum load conditions or during start-up. The exhaust emissions of concern and the emission control techniques can be divided into several categories as shown in *Table 4*. Each pollutant emission reduction technique will be discussed in the following sections.

Nitrogen Oxides Abatement

The mechanism on thermal NO_x production was first postulated by Zeldovich. This is shown in *Figure 20*. It shows the flame temperature of distillate as a function of equivalence ratio. This ratio is a measure of fuel-to-air ratio in the combustor normalized by stoichiometric fuel-to-air ratio. At the equivalence ratio of unity, the stoichiometric conditions are reached. The flame temperature is highest at this point. At equivalence ratios less than 1, we have a “lean” combustor. At the values greater than 1, the combustor is “rich.” All gas turbine combustors are designed to operate in the lean region.

Figure 20 shows that thermal NO_x production rises very rapidly as the stoichiometric flame temperature is reached. Away from this point, thermal NO_x production decreases rapidly. This theory then provides the mechanism of thermal NO_x control. In a diffusion flame combustor, the primary way to control thermal NO_x is to reduce the flame temperature.

NO_x	Lean Head End Liner Water or Steam Injection Dry Low NO_x
CO	Combustor Design Catalytic Reduction
UHC & VOC	Combustor Design
SO_x	Control Sulfur in Fuel
Particulates & PM-10	Fuel Composition
Smoke Reduction	Combustor Design - Fuel Composition - Air Atomization
Particulate Reduction	Fuel Composition - Sulfur - Ash

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Table 4. Emission control techniques

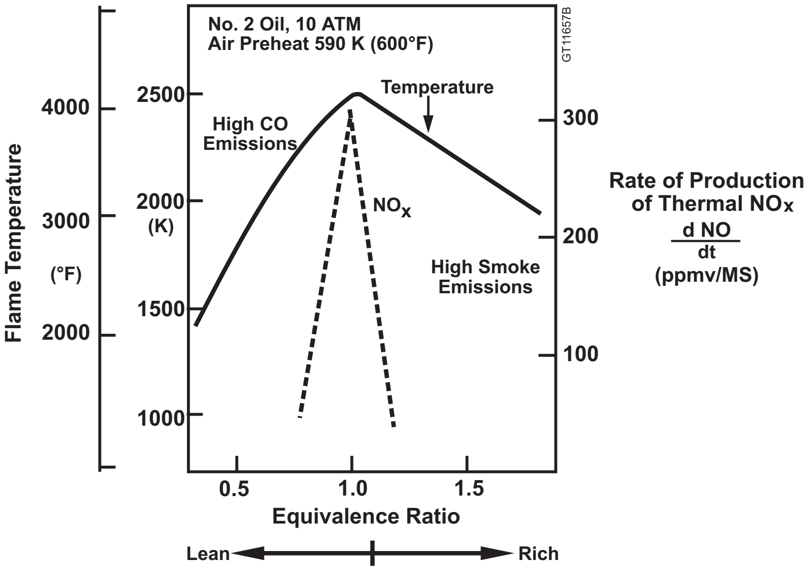


Figure 20. NO_x production rate

Lean Head End (LHE) Combustion Liners

Since the overall combustion system equivalence ratio must be lean (to limit turbine inlet temperature and maximize efficiency), the first efforts to lower NO_x emissions were naturally directed toward designing a combustor with a leaner reaction zone. Since most gas turbines operate with a large amount of excess air, some of this air can be diverted towards the flame end, which reduces the flame temperature.

Leaning out the flame zone (reducing the flame zone equivalence ratio) also reduces the flame length, and thus reduces the residence time a gas molecule spends at NO_x formation temperatures. Both these mechanisms reduce NO_x. The principle of a LHE liner design is shown in *Figure 21.*

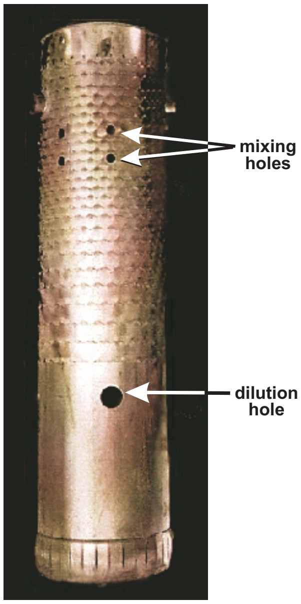
It quickly became apparent that the reduction in primary zone equivalence ratio at full operating conditions was limited because of the large turndown in fuel flow (40 to 1), air flow (30 to 1), and fuel/air ratio (5 to 1) in industrial gas turbines. Further, the flame in a gas turbine is a diffusion flame since the fuel and air are injected directly into the reaction zone. Combustion occurs at or near stoichiometric conditions, and there is substantial recirculation within the reaction zone. These parameters essentially limit the extent of LHE liner technology to a NO_x reduction of 40% at most. Depending upon the liner design, actual reduction achieved varies from 15% to 40%.

Figure 22 compares an MS5001P LHE liner to a standard liner. The liner to the right is the LHE liner. It has extra holes near the head (flame) end and also has a different louver pattern compared to the standard liner. *Table 5* summarizes all LHE liners designed to date. Field test data on MS5002 simple-cycle LHE liners and MS3002J simple-cycle LHE liners are shown in *Figures 23–25.*

One disadvantage of leaning out the head end of the liner is that the CO emissions increase. This is clear from *Figure 24,* which compares CO between the standard and LHE liner for a MS5002 machine.

Water/Steam Injection

Another approach to reducing NO_x formation is to reduce the flame temperature by introducing a heat sink into the flame zone. Both water and steam are very effective at achieving this goal. A penalty in overall efficiency must be paid for the additional fuel required to heat the water to combustor temperature. However, gas turbine output is enhanced because of the additional mass flow through the turbine. By necessity, the water must be of boiler feedwater qual-



- LHE Liner has same diameter and length as standard liner shown at left.
- The number, diameter, and location of the mixing and dilution holes is different in the LHE liner.
- As a result,
  - – more air is introduced in the head end of the LHE combustor
  - – NO_x emissions decrease

Figure 21. Standard simple-cycle MS5002 combustion liner

Figure 22. Louvered low NO_x lean head end combustion liners

ity to prevent deposits and corrosion in the hot turbine gas path area downstream of the combustor.

Water injection is an extremely effective means for reducing NO_x formation; however, the combustor designer must observe certain cautions when using this reduction technique. To maximize the effectiveness of the water used, fuel nozzles have been designed with additional passages to inject water into the combustor head end. The water is thus effectively mixed with the incoming combustion air and reaches the flame zone at its hottest point. In *Figure 26* the NO_x reduction achieved by water injection is plotted as a function of water-to-fuel ratio for an MS7001E machine. Other machines have similar NO_x abatement performance with water injection.

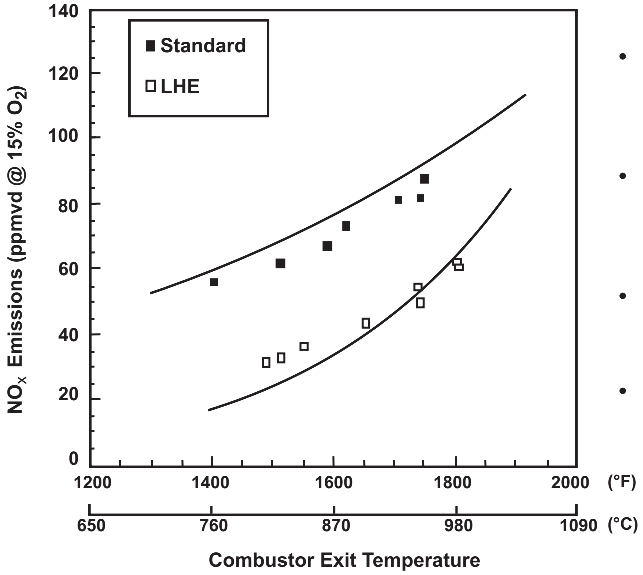
Steam injection for NO_x reduction follows essentially the same path into the combustor head end as water. However, steam is not as effective as water in reducing thermal NO_x. The high latent heat of water acts as a strong thermal sink in reducing the flame temperature.

In general, for a given NO_x reduction, approximately 1.6 times as much steam as water on a mass basis is required for control.

There are practical limits to the amount of water or steam that can be injected into the combustor before serious problems occur. This has been experimentally determined and must be taken into account in all applications if the combustor designer is to ensure long hardware life for the gas turbine user.

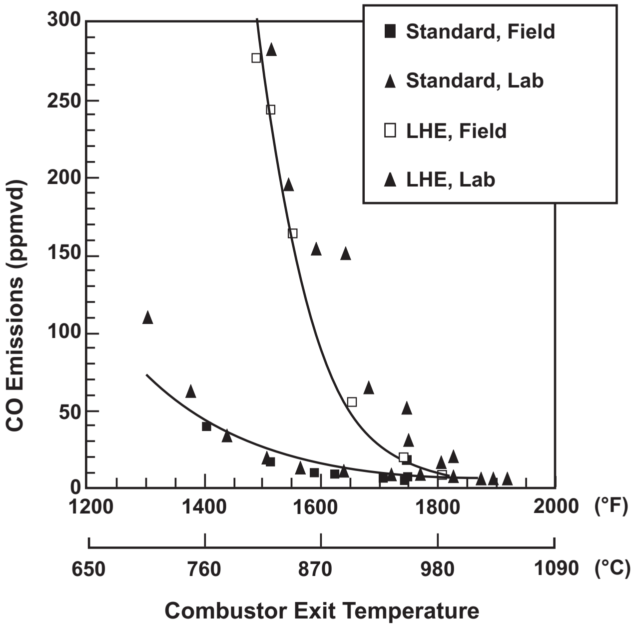
Turbine Model	Laboratory Development Completed	First Field Test
S/C MS3002F S/C MS3002G S/C MS3002J	December-98 December-98 April-97	Fall 1999 to be determined March-99
S/C MS5002B, C, & D S/C MS5001 (All Models)	April-97 1986	September-97 Over 130 operating in field
R/C MS3002J R/C MS5002B & C	February-99 February-99	to be determined to be determined

Table 5. Lean head end (LHE) liner development



- Symbols are field test points collected in Alaska, September 1997
- Solid lines are expectations, from scaled lab NOx emissions
- Field test confirmed ~40% NOx reduction at base load
- Good agreement between lab and field

Figure 23. Field test data: simple-cycle MS5002 NO_x

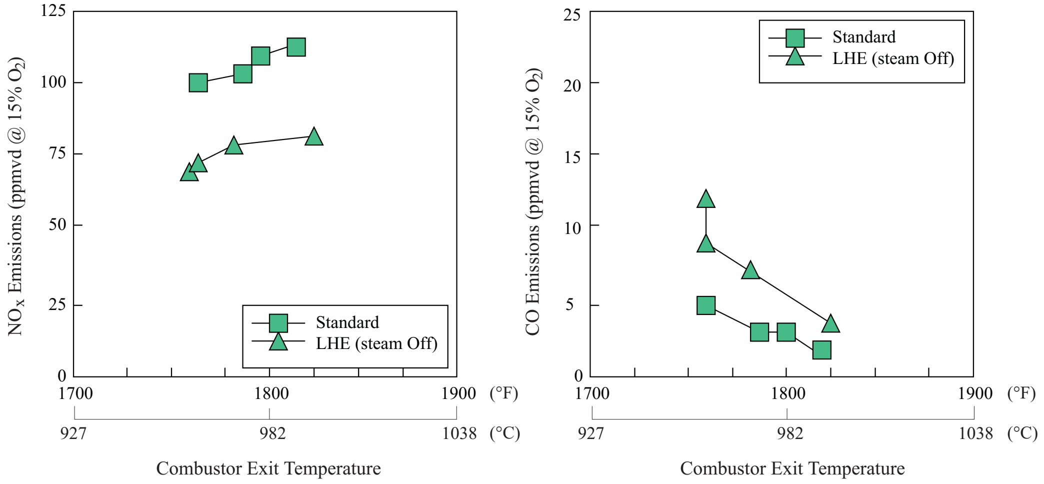


- Field test confirmed small increase in CO at base load, larger increase at part load conditions
- Good agreement between lab and field

Figure 24. Field test data: simple-cycle MS5002 CO

Injecting water/steam in a combustor affects several parameters:

1. **Dynamic Pressure Activity within the Combustor.** Dynamic pressures can be defined as pressure oscillations within the combustor driven by non-uniform heat release rate inherent in any diffusion flame or by the weak coupling between heat release rate, turbulence, and acoustic modes. An example of the latter is selective amplification of combustion roar by



- 30% reduction in NO_X with negligible increase in CO.
- Injecting steam further reduces NO_X.

Figure 25. Field test data: simple-cycle MS3002J with steam injection for power augmentation

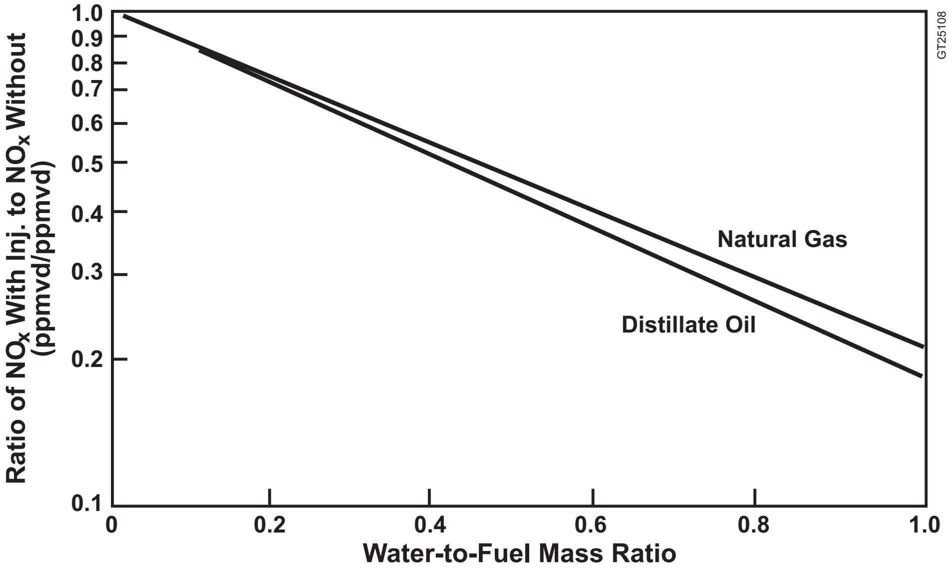


Figure 26. MS7001E NO_x reduction with water injection

the acoustic modes of the duct. Frequencies range from near zero to several hundred hertz. *Figure 27* shows dynamic pressure activity for both water injection and steam injection for an MS7001E combustor. Water injection tends to excite the dynamic activity more than steam injection. The oscillating pressure loads on the combustion hardware act as vibratory forcing functions and therefore must be minimized to ensure long hardware

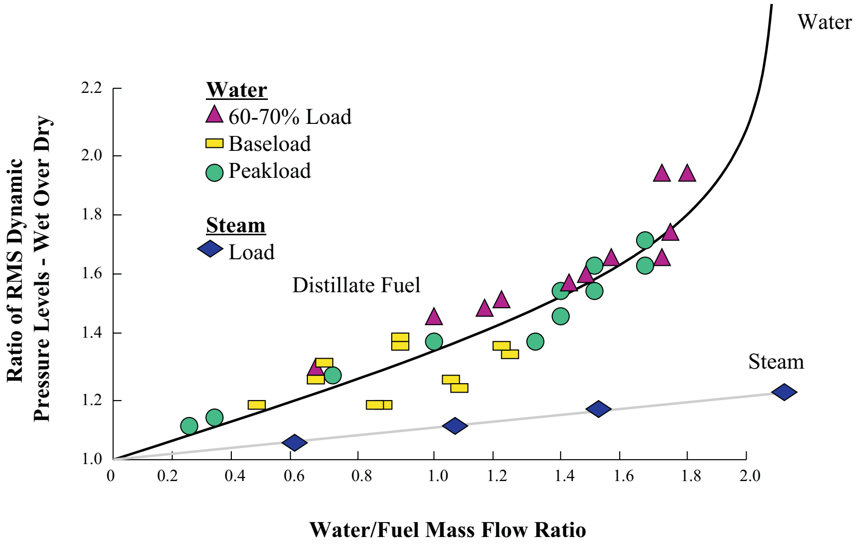


Figure 27. MS7001E combustor dynamic pressure activity

life. Through combustor design modifications such as the addition of a multi-nozzle fuel system, significant reductions in dynamic pressure activity are possible.

2. **Carbon Monoxide Emissions.** As more and more water/steam is added to the combustor, a point is reached at which a sharp increase in carbon monoxide is observed. This point has been dubbed the "knee of the curve". Once the knee has been reached for any given turbine inlet temperature, one can expect to see a rapid increase in carbon monoxide emissions with the further addition of water or steam. Obviously, the higher the turbine inlet temperature, the more tolerant the combustor is to the addition of water for NO_x control. *Figure 28* shows the relationship of carbon monoxide emissions to water injection for a MS7001B machine for natural gas fuel. *Figure 29* shows the effect of steam injection on CO emissions for a typical MS7001EA. Unburned hydrocarbons have a similar characteristic with NO_x water or steam injection as carbon monoxide. *Figure 30* shows the MS7001EA gas turbine unburned hydrocarbon versus firing temperature characteristic with steam injection.
3. **Combustion Stability.** Increasing water/steam injection reduces combustor-operating stability.
4. **Blow Out.** With increasing water/steam injection, eventually a point will be reached when the flame will blow out. This point is the absolute limit of NO_x control with water/steam injection.

Carbon Monoxide Control

There are no direct carbon monoxide emission reduction control techniques available within the gas turbine. Basically the carbon monoxide emissions within the gas turbine combustor can be viewed as resulting from incomplete com-

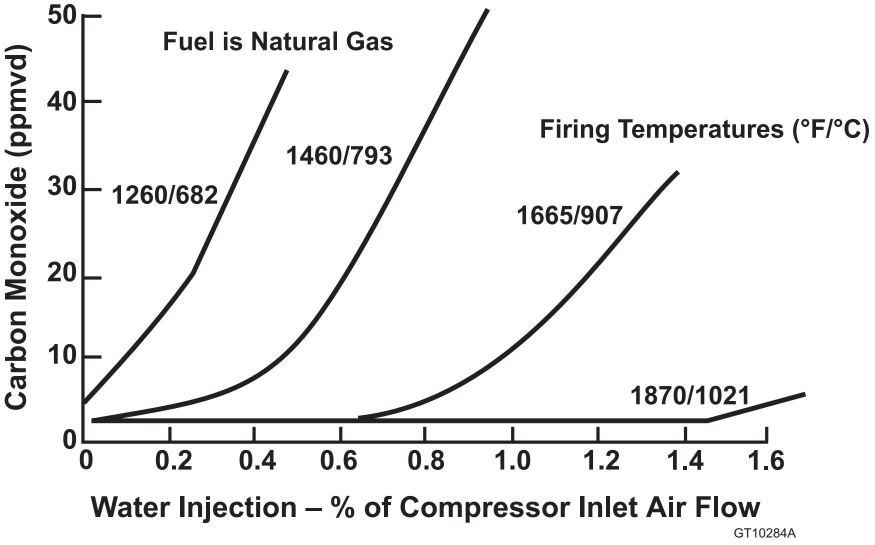


Figure 28. Carbon monoxide vs. water injection effect of firing temperature – MS7001B

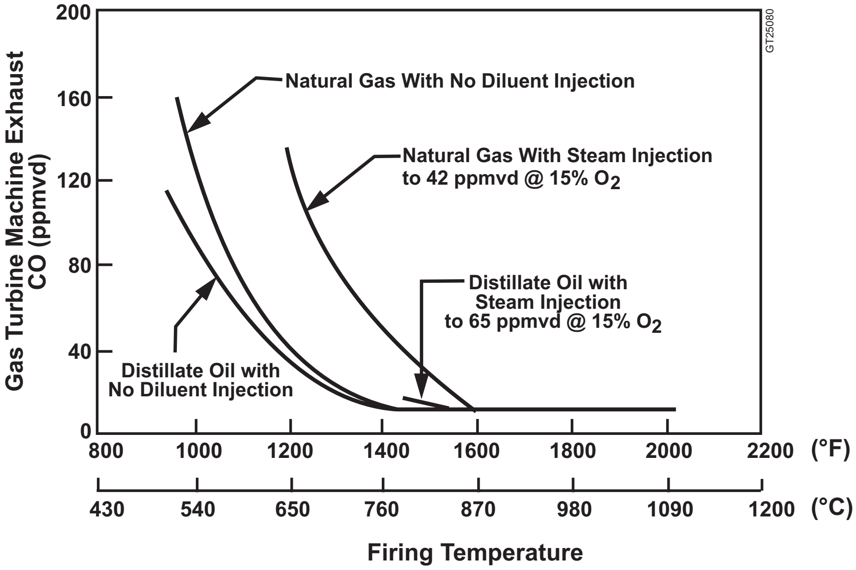


Figure 29. CO emissions for MS7001EA

bustion. Since the combustor design maximizes combustion efficiency, carbon monoxide emissions are minimized across the gas turbine load range of firing temperatures. Reviewing *Figure 5* shows that the carbon monoxide emission levels increase at lower firing temperatures. In some applications where carbon monoxide emissions become a concern at low loads (firing temperatures), the increase in carbon monoxide can be lowered by:

- reducing the amount of water/steam

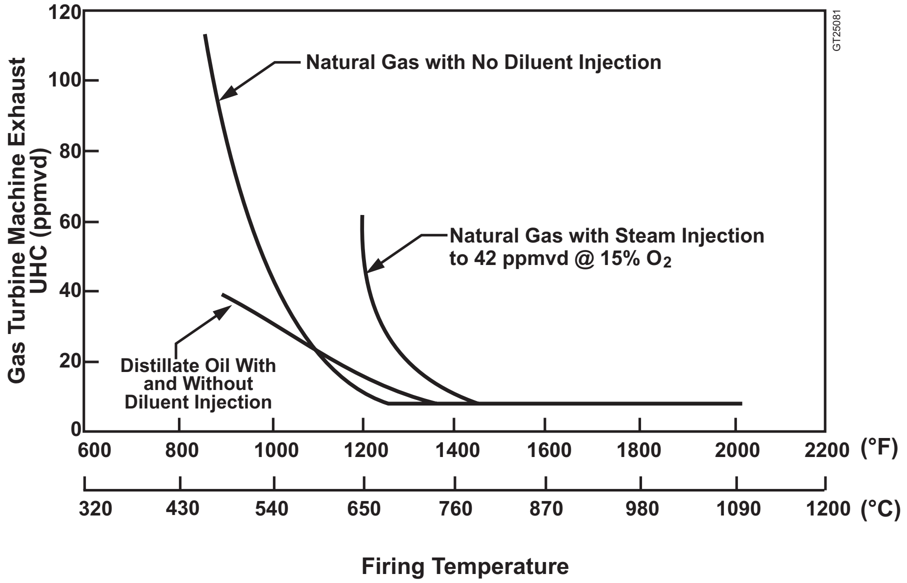


Figure 30. UHC emissions for MS7001EA

injection for NO_x control (if allowed)

– or –

- closing the inlet guide vanes, which will increase the firing temperature for the same load.

Unburned Hydrocarbons Control

Similar to carbon monoxide, there are also no direct UHC reduction control techniques used within the gas turbine. UHCs are also viewed as incomplete combustion, and the combustor is designed to minimize these emissions. The same indirect emissions control techniques can be used for unburned hydrocarbons as for carbon monoxide.

Particulate and Smoke Reduction

Control techniques for particulate emissions with the exception of smoke are limited to control of the fuel composition.

Although smoke can be influenced by fuel composition, combustors can be designed which minimize emission of this pollutant. Heavy fuels such as crude oil and residual oil have low hydrogen levels and high carbon residue, which increase smoking tendencies. GE has designed heavy-fuel combustors that have smoke performance comparable with those which burn distillate fuel.

Crude and residual fuel oil generally contain alkali metals (Na, K) in addition to vanadium and lead, which cause hot corrosion of the turbine nozzles and buckets at the elevated firing temperatures of today's gas turbine. If the fuel is washed, water soluble compounds (alkali salts) containing the contaminants are removed. Filtration, centrifuging, or electrostatic precipitation are also effective on reducing the solid contaminants in the combustion products.

Contaminants that cannot be removed from the fuel (vanadium compounds) can be controlled through the use of inhibitors. GE uses addition of magnesium to control vanadium corrosion in its heavy-duty gas turbines. These magnesium additives always form ash within the hot gas path components. This process generally requires control and removal of added ash deposits from the turbine. The additional ash will contribute to the exhaust particulate emissions. Generally, the expected increase can be calculated from an analysis of the particular fuel being burned.

In some localities, condensable compounds such as SO_3 and condensable hydrocarbons are considered particulates. SO_3, like SO_2, can best be minimized by controlling the amount of sulfur in the fuel. The major problem associated with sulfur compounds in the exhaust comes from the difficulty of measurement. Emissions of UHCs, which are a liquid or solid at room temperature, are very low and only make a minor contribution to the exhaust particulate loading.

Water/Steam Injection Hardware

The injection of water or steam into the combustion cover/fuel nozzle area has been the primary method of NO_x reduction and control in GE heavy-duty gas turbines since the early 1970s. The same design gas turbine equipment is supplied for conversion retrofits to existing gas turbines for either injection method. Both NO_x control injection methods require a microprocessor controller, therefore turbines with older controls need to have their control system upgraded to Mark V or Mark VI SPEEDTRONIC™ controls conversion. The control system for both NO_x control injection methods utilizes the standard GE gas turbine control philosophy of two separate independent methods for shutting off the injection flow.

The NO_x water injection system is shown schematically in *Figure 31* and consists of a water pump and filter, water flowmeters, water stop and flow control valves. This material is supplied on a skid approximately 10 x 20 feet in size for mounting at the turbine site. The water from the skid is piped to the turbine base where it is manifold to each of the fuel nozzles using pigtails. The water injection at the combustion chamber is through passages in the fuel nozzle assembly. A typical water injection fuel nozzle assembly is shown schematically in *Figure 32.* For this nozzle design there are eight or twelve

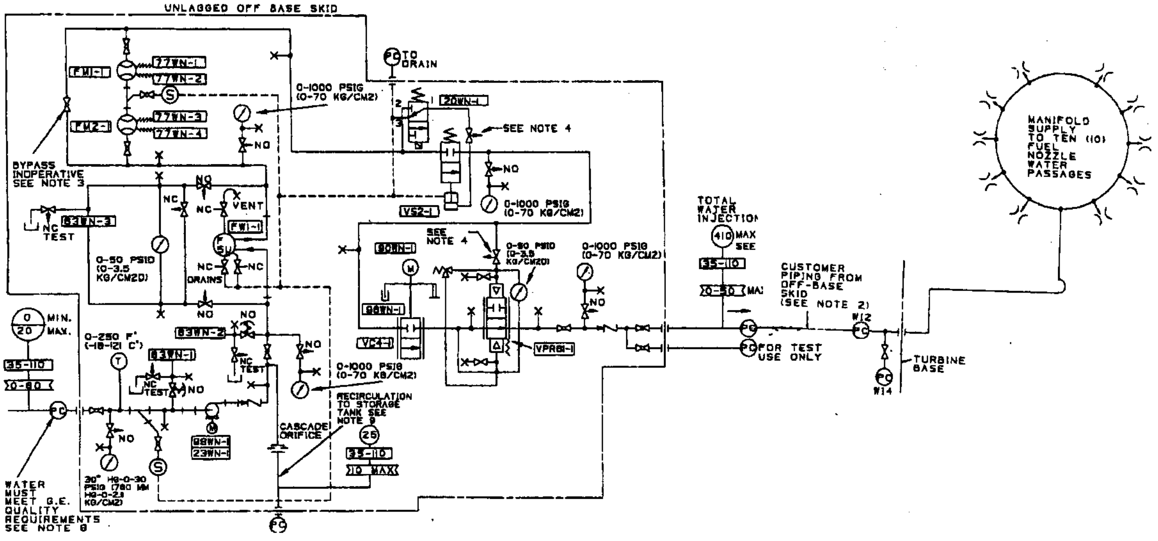


Figure 31. Schematic piping – water injection system

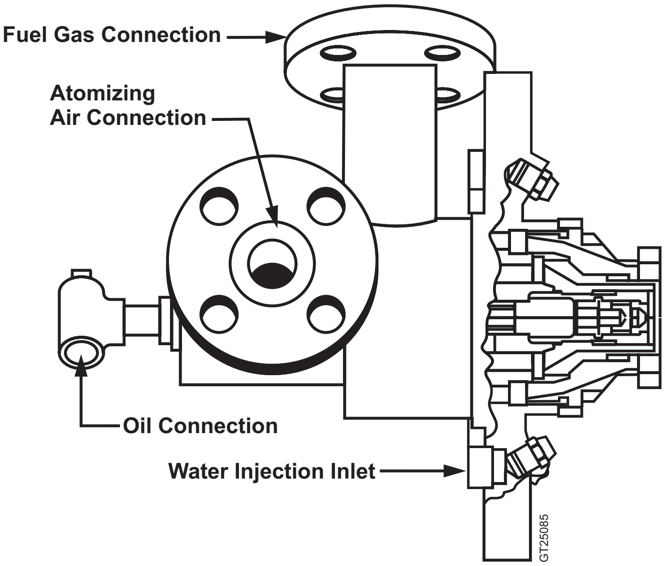


Figure 32. Water injection fuel nozzle assembly

water spray nozzles directing the water injection spray towards the fuel nozzle tip swirler. While this design is quite effective in controlling the NO_x emissions, the water spray has a tendency to impinge on the nozzle tip swirler and on the liner cap/cowl assembly. Resulting thermal strain usually leads to cracks, which limits the combustion inspections to 8000 hours or less. To eliminate this cracking, the latest design water-injected fuel nozzle is the breech-load fuel nozzle. (*See Figure 33.*) In this design the water is injected through a central fuel nozzle passage, injecting the water flow directly into the combustor flame. Since the water injection spray does not impinge on the fuel nozzle swirler or the combustion cowl assembly, the breech load fuel nozzle design results in lower maintenance and longer combustion inspection intervals for NO_x water injection applications.

The NO_x steam injection system is shown schematically in *Figure 34*, and consists of a steam flowmeter, steam control valve, steam stop valve, and steam blowdown valves. This material is supplied loose for mounting near the turbine base by the customer. The steam-injection flow goes to the steam-injection manifold on the turbine base. Flexible pigtails are used to connect from the steam manifold to each combustion chamber. The steam injection into the combustion chamber is through machined passages in the combustion can cover. A typical steam-injection combustion cover with the machined steam-injection passage and steam injection nozzles is shown in *Figure 35*.

Water quality is of concern when injecting water or steam into the gas turbine due to potential problems with hot gas path corrosion, and effects to the injection control equipment. The injected water or steam must be clean and free of impurities and solids. The general requirements of the injected water or steam quality are shown in *Table 6*. Total impurities into the gas turbine are a total of the ambient air, fuel, and injected water or steam. The total impurities

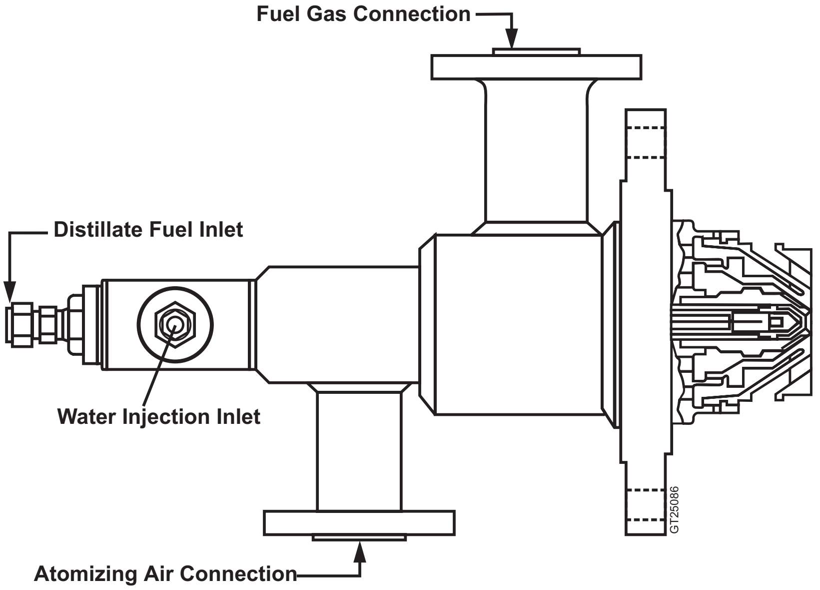


Figure 33. Breech-load fuel nozzle assembly

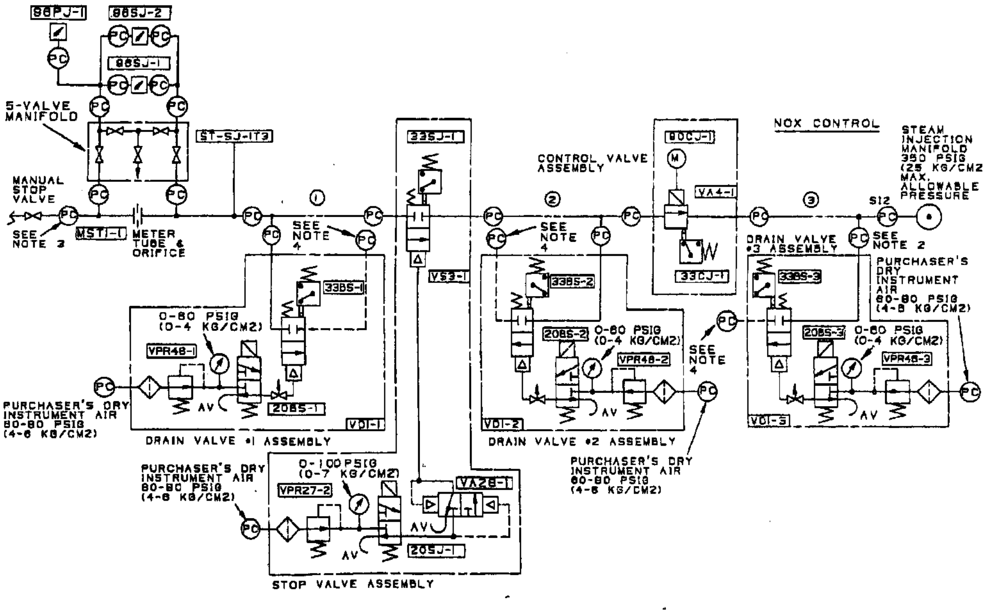
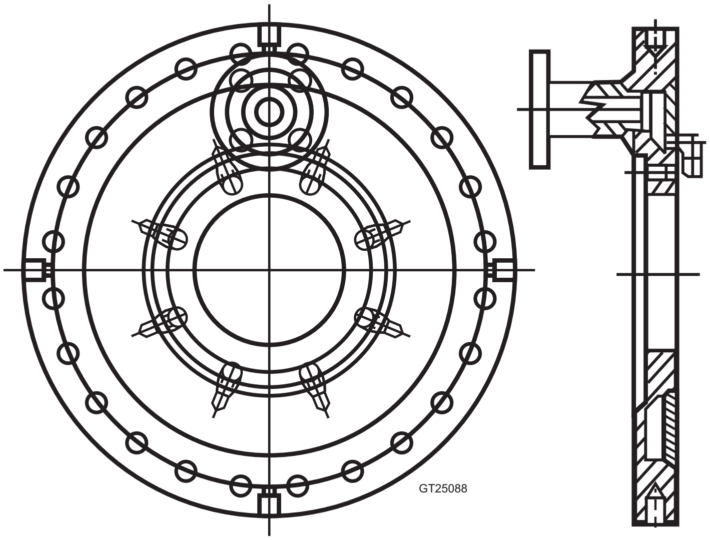


Figure 34. Schematic piping – steam injection system

requirement may lower the water or steam-injection quality requirements. It is important to note that the total impurities requirement is provided relative to the input fuel flow.

Minimum NO_x Levels

As described above, the methods used to reduce thermal NO_x inside the gas turbine are by combustor design or by diluent injection. To see



NOTE: This drawing is not to be used for Guarantees

Figure 35. Combustion cover – steam injection

• **WATER/STEAM QUALITY**	
Total Dissolved Solids	5.0 ppm Max.
Total Trace Metals (Sodium + Potassium + Vanadium + Lead)	0.5 ppm Max.
pH	6.5 – 7.5
NOTE: Quality requirements can generally be satisfied by demineralized water.	
• **TOTAL LIMITS IN ALL SOURCES** (Fuel, Steam, Water, Air)	
Contaminant	**Max. Equivalent Concentration (ppm – wt)**
Sodium + Potassium	1.0
Lead	1.0
Vanadium	0.5
Calcium	2.0

Table 6. Water or steam injection quality requirements

NO_x emissions from each frame size without any control, refer to *Table 3*. With the LHE liner design, dry (no water/steam injection) NO_x emissions could be reduced by 15–40% relative to standard liner. This is the limit of LHE liner technology.

With water or steam injection, significant reduction in NO_x is achieved. The lowest achievable NO_x values with water/steam injection from GE heavy-duty gas turbines are also shown in *Table 3*. The table provides the current minimum NO_x levels for both methane natural gas fuel and #2 distillate fuel oil.

Maintenance Effects

As described previously, the methods used to control gas turbine exhaust emissions have an effect on the gas turbine maintenance intervals. *Table 7* provides the recommended combustion inspection intervals for current design Advanced Technology combustion systems used in base load continuous duty gas turbines without NO_x control systems and the recommended combustion inspection intervals with the various NO_x control methods at the NO_x ppmvd @ 15% O_2 levels shown. Both natural gas fuel and #2 distillate fuel recommended combustion inspection intervals are included. Review of *Table 7* shows that the increased combustion dynamics (as the combustor design goes from dry to steam injection) and then to water injection results in reductions in the recommended combustion inspection intervals.

Performance Effects

As mentioned previously the control of NO_x can impact turbine firing temperature and result in gas turbine output changes. Additionally, the injection of water or steam also impacts gas turbine output, heat rate, and exhaust temperature. *Figure 36* shows the impact of NO_x injection on these gas turbine parameters when operating at base load for all single shaft design gas turbines. Note that the injection rate is shown as a percentage of the gas turbine compressor inlet airflow on a weight basis. The output and heat rate change is shown on a percent basis while exhaust temperature is

		Natural Gas/ No. 2 Distillate ppmvd @ 15% O_2	**Natural Gas Fired Hours of Operation Water/Steam Injection**	**No. 2 Distillate Fired Hours of Operation Water/Steam Injection**
MS5001P N/T	Dry	142/211	12,000/12,000	12,000/12,000
	NSPS	87/86	12,000/12,000	6,000/6,000
		42/65	6,000/6,000	6,000/6,000
		42/42	6,000/6,000	1,500/4,000
MS6001B	Dry	148/267	12,000/12,000	12,000/12,000
	NSPS	94/95	8,000/8,000	6,000/6,000
		42/65	8,000/8,000	8,000/8,000
		42/42	8,000/8,000	4,000/4,000
MS7001E	Dry	154/228	8,000/8,000	8,000/8,000
	NSPS	96/97	8,000/8,000	8,000/8,000
		42/65	6,500/8,000	6,500/8,000
		42/42	6,500/8,000	1,500/3,000
	MNQC	25/42	8,000/8,000	6,000/6,000
MS9001E	Dry	147/220	8,000/8,000	8,000/8,000
		42/65	6,500/8,000	6,500/8,000

Inspection Intervals reflect current hardware. Older units with earlier vintage hardware will have lower Inspection intervals.

The above values represent initial recommended combustion inspection intervals. The intervals are subject to change based on experience.

Base Load Operation.
NSPS NO_x levels are 75 ppm with heat rate correction included.

GT25093

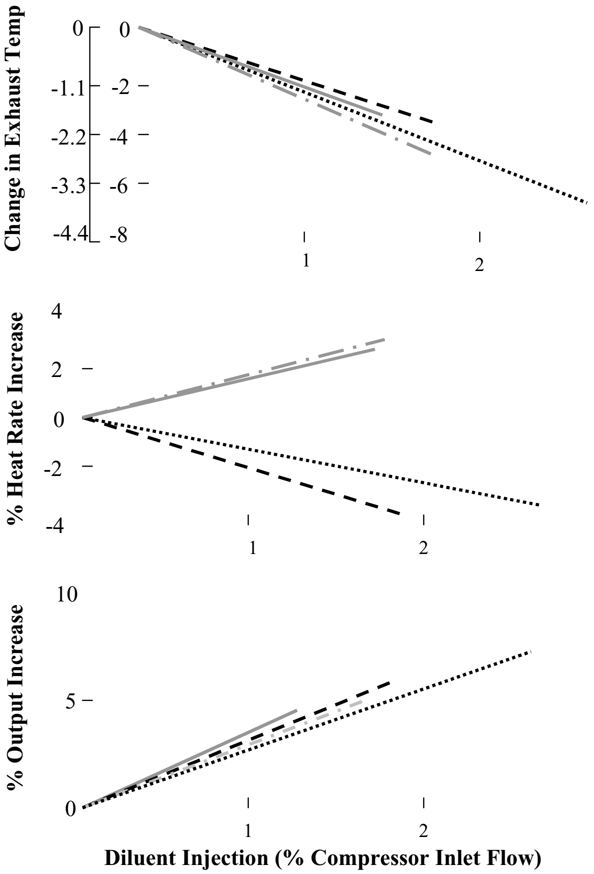
Table 7. Estimated ISO NO_x level effects on combustion inspection intervals

shown in degrees F. Review of *Figure 36* shows that turbine output is increased when NO_x injection is used. The gas turbine load equipment must also be capable of this output increase or control changes must be made in order to reduce the gas turbine output.

Summary

The emissions characteristics of gas turbines have been presented both at base load and part load conditions. The interaction of emission control on other exhaust emissions as well as the effects on gas turbine maintenance and performance have also been presented. The minimum controllable NO_x levels using LHE and water/steam injection techniques have also been presented. Using this information, emissions estimates and the overall effect of the various emission control methods can be estimated.

It is not the intent of this paper to provide site-specific emissions. For these values, the customer must contact GE.



Solid Line = Water Inj for 5001
Dashed Line = Steam Inj for 5001
Chaindashed Line = Water Inj for 61, 71, 91
Dotted Line = Steam Inj for 61, 71, 91

Figure 36. Performance effects vs. diluent injection

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GE Energy

Heavy-Duty Gas Turbine Operating and Maintenance Considerations

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GER-3620K (12/04)

CONTENTS

INTRODUCTION

Maintenance costs and availability are two of the most important concerns to a heavy-duty gas turbine equipment owner. Therefore, a well thought out maintenance program that optimizes the owner's costs and maximizes equipment availability should be instituted. For this maintenance program to be effective, owners should develop a general understanding of the relationship between the operating plans and priorities for the plant, the skill level of operating and maintenance personnel, and all equipment manufacturer's recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting component life and proper operation of the equipment.

In this paper, operating and maintenance practices for heavy-duty gas turbines will be reviewed, with emphasis placed on types of inspections plus operating factors that influence maintenance schedules. A well-planned maintenance program will result in maximum equipment availability and optimization of maintenance costs.

Note:

- The operation and maintenance practices outlined in this document are based on full utilization of GE approved parts, repairs, and services.
- The operating and maintenance discussions presented in this paper are generally applicable to all GE heavy-duty gas turbines; i.e., MS3000, 5000, 6000, 7000 and 9000. For purposes of illustration, the MS7001EA was chosen. Specific questions on a given machine should be directed to the local GE Energy representative.

MAINTENANCE PLANNING

Advanced planning for maintenance is a necessity for utility, industrial, independent power producers and cogeneration plant operators in order to minimize downtime. Also the correct implementation of planned maintenance and inspection provides direct benefits in reduced forced outages and increased starting reliability, which in turn can also reduce unscheduled repairs and downtime. The primary factors that affect the maintenance planning process are shown in *Figure 1* and the owners' operating mode and practices will determine how each factor is weighted.

Parts unique to a gas turbine requiring the most careful attention are those associated with the combustion process together with those exposed to high temperatures from the hot gases discharged from the combustion system. They are called the combustion section and hot gas path parts and will include combustion liners, end caps, fuel nozzle assemblies, crossfire tubes, transition pieces, turbine nozzles, turbine stationary shrouds and turbine buckets.

An additional area for attention, though a longer-term concern, is the life of the compressor and turbine rotors.

The basic design and recommended maintenance of GE heavy-duty gas turbines are oriented toward:

- Maximum periods of operation between inspection and overhauls
- In-place, on-site inspection and maintenance
- Use of local trade skills to disassemble, inspect and re-assemble

In addition to maintenance of the basic gas turbine, the control devices, fuel metering equipment, gas turbine auxiliaries, load package, and other station auxiliaries also require periodic servicing.

It is apparent from the analysis of scheduled outages and forced outages (*Figure 2*) that the primary maintenance effort is attributed to five basic systems: controls and accessories, combustion, turbine, generator and balance-of-plant. The unavailability of controls and accessories is generally composed of short-duration outages, whereas conversely the other four systems are composed of fewer, but usually longer-duration outages.

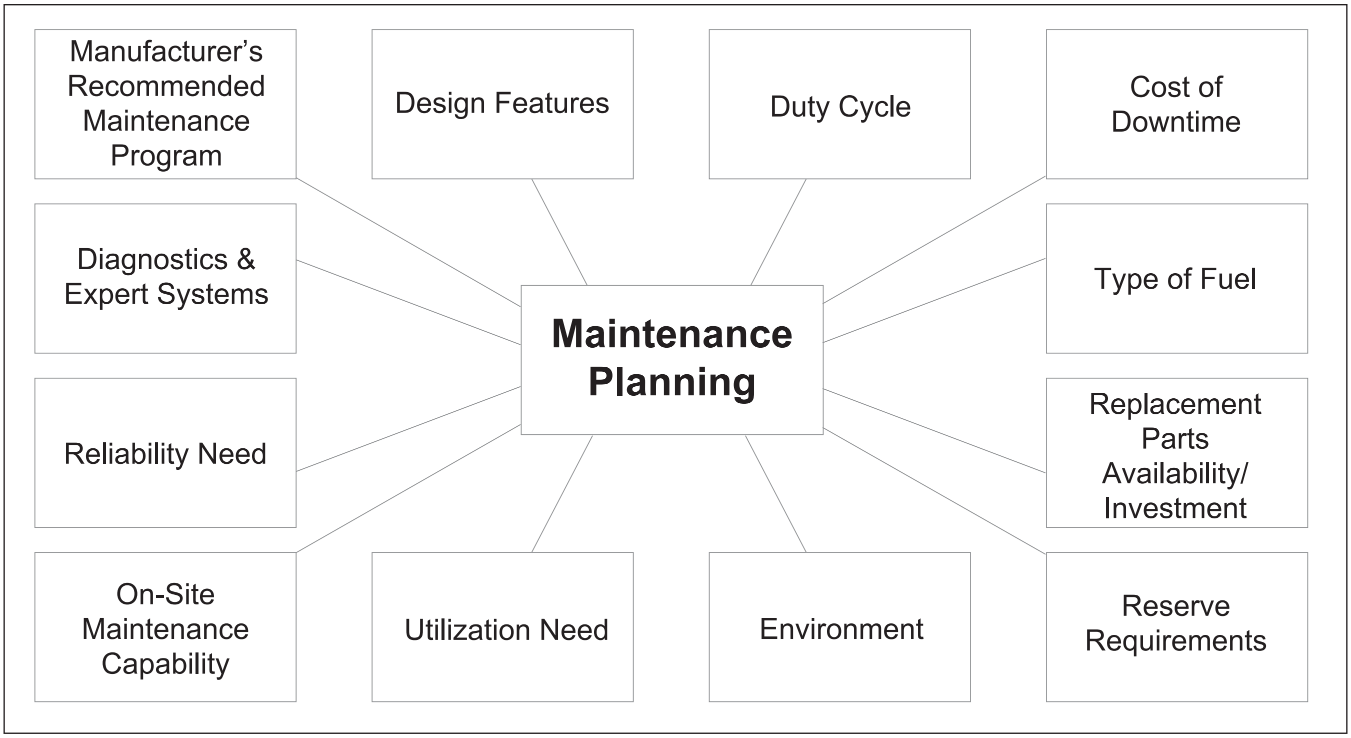


Figure 1. Key factors affecting maintenance planning

The inspection and repair requirements, outlined in the Operations and Maintenance Manual provided to each owner, lend themselves to establishing a pattern of inspections. In addition, supplementary information is provided through a system of Technical Information Letters. This updating of information, contained in the Operations and Maintenance Manual, assures optimum installation, operation and maintenance of the turbine. Many of the Technical Information Letters contain advisory technical recommendations to help resolve issues (as they become known) and to help improve the operation, maintenance, safety, reliability

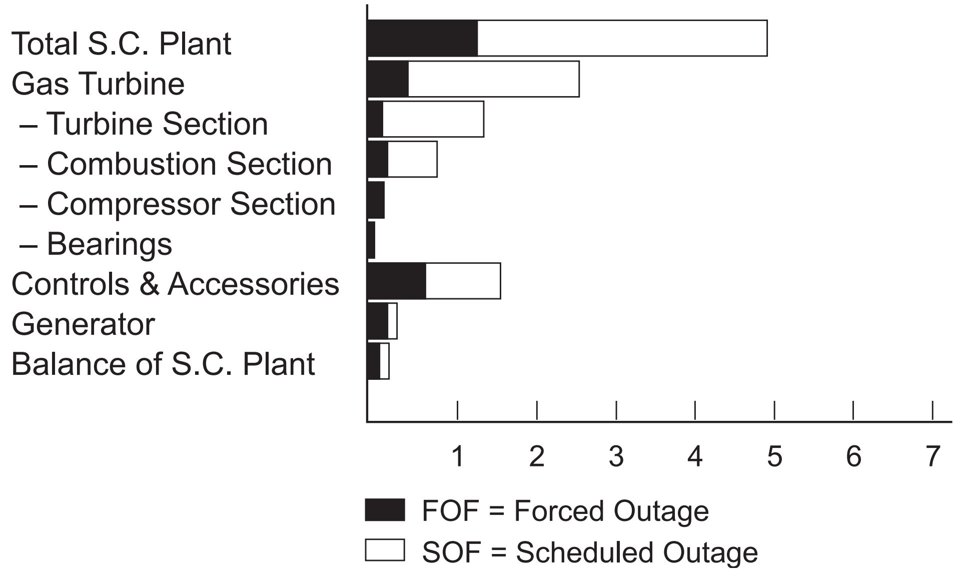


Figure 2. Plant level – top five systems contribution to downtime

or availability of the turbine. The recommendations contained in Technical Information Letters should be reviewed and factored into the overall maintenance planning program.

For a maintenance program to be effective, from both a cost and turbine availability standpoint, owners must develop a general understanding of the relationship between their operating plans and priorities for the plant and the manufacturer's recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting the life and proper operation of the equipment. Each of these issues will be discussed as follows in further detail.

GAS TURBINE DESIGN MAINTENANCE FEATURES

The GE heavy-duty gas turbine is designed to withstand severe duty and to be maintained onsite, with off-site repair required only on certain combustion components, hot-gas-path parts and rotor assemblies needing specialized shop service. The following features are designed into GE heavy-duty gas turbines to facilitate on-site maintenance:

- All casings, shells and frames are split on machine horizontal centerline. Upper halves may be lifted individually for access to internal parts.
- With upper-half compressor casings removed, all stator vanes can be slid circumferentially out of the casings for inspection or replacement without rotor removal. On most designs, the variable inlet guide vanes (VIGVs) can be removed radially with upper half of inlet casing removed.
- With the upper-half of the turbine shell lifted, each half of the first stage nozzle assembly can be removed for inspection, repair or replacement without rotor removal. On some units, upper-half, later-stage nozzle assemblies are lifted with the turbine shell, also allowing inspection and/or removal of the turbine buckets.
- All turbine buckets are moment-weighed and computer charted in sets for rotor spool assembly so that they may be replaced without the need to remove or rebalance the rotor assembly.
- All bearing housings and liners are split on the horizontal centerline so that they may be inspected and replaced, when necessary. The lower half of the bearing liner can be removed without removing the rotor.
- All seals and shaft packings are separate from the main bearing housings and casing structures and may be readily removed and replaced.
- On most designs, fuel nozzles, combustion liners and flow sleeves can be removed for inspection, maintenance or replacement without lifting any casings. All major accessories, including filters and coolers, are separate assemblies that are readily accessible for inspection or maintenance. They may also be individually replaced as necessary.

Inspection aid provisions have been built into GE heavy-duty gas turbines to facilitate conducting several special inspection procedures. These special procedures provide for the visual inspection and clearance measurement of some of the critical internal turbine gas-path components without removal of the gas turbine outer casings and shells. These procedures include gas-path borescope inspection and turbine nozzle axial clearance measurement.

A GE gas turbine is a fully integrated design consisting of stationary and rotating mechanical, fluid, thermal, and electrical systems. The turbine's performance, as well as the performance of each component within the turbine, is dependent upon the operating inter-relationship between internal components. GE's tollgated engineering process evaluates the impacts of design changes or repairs on the interaction between components and systems. This design, evaluation, testing, and approval process is predicated upon assuring the proper balance and interaction between all components and systems for safe, reliable, and economical operation.

Whether a part is new, repaired, or modified, failure to evaluate the full system impact may have unquantifiable negative impacts on the operation and reliability of the entire system. The use of non-GE approved parts, repairs, and maintenance practices represent a significant risk. Pursuant to the governing terms and conditions, warranties and performance guarantees are conditioned upon proper storage, installation, operation, and maintenance, as well as conformance to GE approved operating instruction manuals and repair/modification procedures.

Borescope Inspections

GE heavy-duty gas turbines incorporate provisions in both compressor casings and turbine shells for gas-path visual inspection of intermediate compressor rotor stages, first, second and third-stage turbine buckets and turbine nozzle partitions by means of the optical borescope. These provisions, consisting of radially aligned holes through the compressor casings, turbine shell and internal stationary turbine shrouds, are designed to allow the penetration of an optical borescope into the compressor or turbine flow path area, as shown in *Figure 3*. Boroscope inspection access locations for F Class gas turbines can be found in Appendix E.

An effective borescope inspection program can result in removing casings and shells from a turbine unit only when it is necessary to repair or replace parts. *Figure 4* provides a recommended interval for a planned borescope inspection program following initial base line inspections. It should be recognized that these borescope inspection intervals are based on average unit operating modes. Adjustment of these borescope intervals may be made based on operating experience and the individual unit mode of operation, the fuels used and the results of previous borescope inspections.

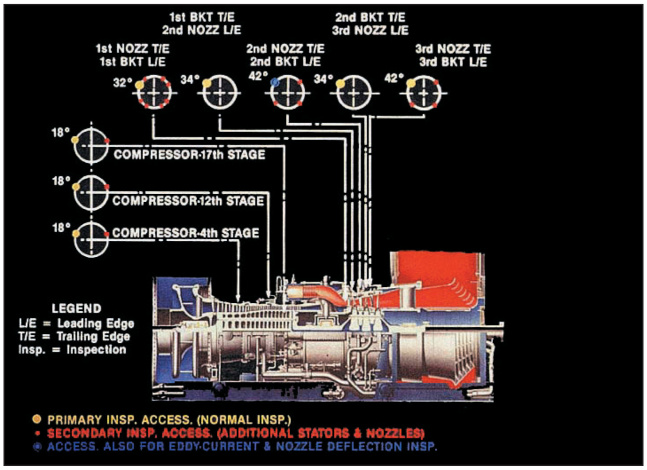


Figure 3. MS7001E gas turbine borescope inspection access locations

Borescope	Gas and Distillate Fuel Oil	At Combustion Inspection or Annually, Whichever Occurs First
	Heavy Fuel Oil	At Combustion Inspection or Semiannually, Whichever Occurs First

Figure 4. Borescope inspection programming

The application of a monitoring program utilizing a borescope will allow scheduling outages and pre-planning of parts requirements, resulting in lower maintenance costs and higher availability and reliability of the gas turbine.

MAJOR FACTORS INFLUENCING MAINTENANCE AND EQUIPMENT LIFE

There are many factors that can influence equipment life and these must be understood and accounted for in the owner's maintenance planning. As indicated in *Figure 5*, starting cycle, power setting, fuel and level of steam or water injection are key factors in determining the maintenance interval requirements as these factors directly influence the life of critical gas turbine parts.

- Cyclic Effects
- Firing Temperature
- Fuel
- Steam/Water Injection

Figure 5. Maintenance cost and equipment life are influenced by key service factors

In the GE approach to maintenance planning, a gas fuel unit operating continuous duty, with no water or steam injection, is established as the baseline condition which sets the maximum recommended maintenance intervals. For operation that differs from the baseline, maintenance factors are established that determine the increased level of maintenance that is required. For example, a maintenance factor of two would indicate a maintenance interval that is half of the baseline interval.

Starts and Hours Criteria

Gas turbines wear in different ways for different service-duties, as shown in *Figure 6*. Thermal mechanical fatigue is the dominant limiter of life for peaking machines, while creep, oxidation, and corrosion are the dominant limiters of life for continuous duty machines. Interactions of these mechanisms are considered in the GE design criteria, but to a great extent are second order effects. For that reason, GE bases gas turbine maintenance requirements on independent counts of starts and hours. Whichever criteria limit is first reached determines the maintenance interval. A graphical display of the GE approach is shown in *Figure 7*. In this figure, the inspection interval recommendation is defined by the rectangle established by the starts and hours criteria. These recommendations for inspection fall within the design life expectations and are selected such that components verified to be acceptable for continued use at the inspection point will have low risk of failure during the subsequent operating interval.

- **Continuous Duty Application**
  - Rupture
  - Creep Deflection
  - High-Cycle Fatigue
  - Corrosion
  - Oxidation
  - Erosion
  - Rubs/Wear
  - Foreign Object Damage
- **Cyclic Duty Application**
  - Thermal Mechanical Fatigue
  - High-Cycle Fatigue
  - Rubs/Wear
  - Foreign Object Damage

Figure 6. Causes of wear – hot gas path components

An alternative to the GE approach, which is sometimes employed by other manufacturers, converts each start cycle to an equivalent number of operating hours (EOH) with inspection intervals based on the equivalent hours count. For the reasons previously stated, GE does not agree with this approach. This logic can create the impression of longer intervals; while in reality more frequent maintenance inspections are required. Referring again to *Figure 7*, the starts and hours inspection “rectangle” is reduced in half as defined by the diagonal line from the starts limit at the upper left hand corner to the hours limit at the lower right hand corner. Midrange duty applications, with hours per start ratios of 30-50, are particularly penalized by this approach.

This is further illustrated in *Figure 8* for the example of an MS7001EA gas turbine operating on gas fuel, at base load conditions with no steam or water injection or trips from load. The unit operates 4000 hours and 300 starts per year. Following GE’s recommendations, the operator would perform the hot gas path inspection after four years of operation, with starts being the limiting condition. Performing maintenance on this same unit based on an equivalent hours criteria would require a hot gas path inspection after 2.4 years. Similarly, for a continuous duty application operating 8000 hours and 160 starts per year, the GE recommendation would be to perform the hot gas path inspection after three years of operation with the operating hours being the limiting condition for this case. The equivalent hours criteria would set the hot gas path inspection after 2.1 years of operation for this application.

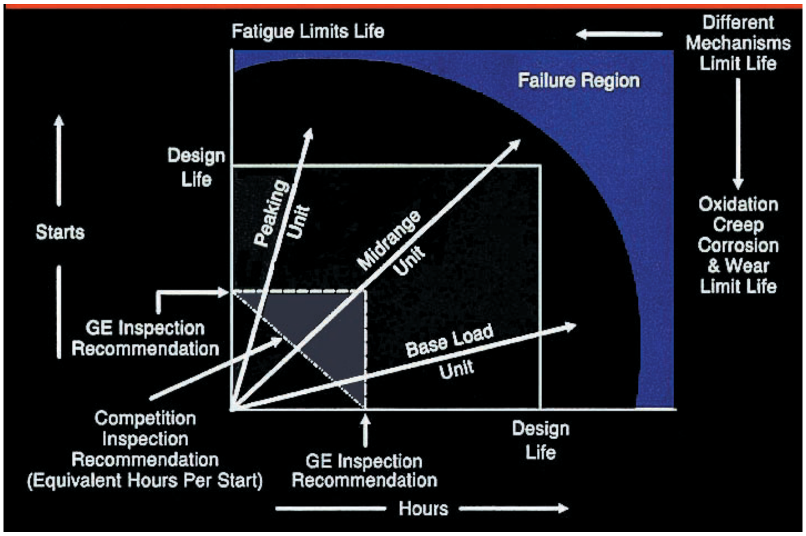


Figure 7. GE bases gas turbine maintenance requirements on independent counts of starts and hours

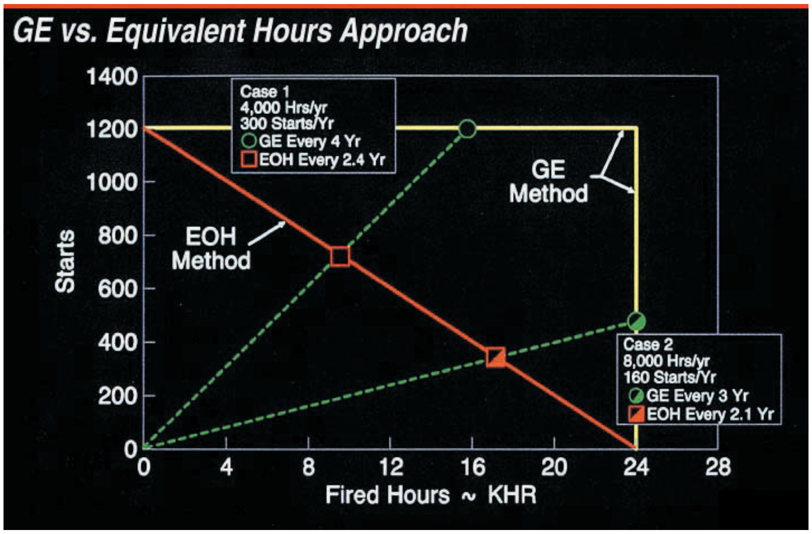


Figure 8. Hot gas path maintenance interval comparisons. GE method vs. EOH method

Service Factors

While GE does not ascribe to the equivalency of starts to hours, there are equivalencies within a wear mechanism that must be considered. As shown in *Figure 9*, influences such as fuel type and quality, firing temperature setting, and the amount of steam or water injection are considered with regard to the hours-based criteria. Startup rate and the number of trips are considered with regard to the starts-based criteria. In both cases, these influences may act to reduce the maintenance intervals. When these service or maintenance factors are involved in a unit's operating profile, the hot-gas-path maintenance “rectangle” that describes the specific maintenance criteria for this operation is reduced from the ideal case, as illustrated in *Figure 10*. The following discussion will take a closer look at the key operating factors and how they can impact maintenance intervals as well as parts refurbishment/replacement intervals.

Fuel

Fuels burned in gas turbines range from clean natural gas to residual oils and impact maintenance, as illustrated in *Figure 11*. Heavier hydrocarbon fuels

Typical Max Inspection Intervals (MS6B/MS7EA)

Hot Gas Path Inspection	24,000 hrs or 1200 starts
Major Inspection	48,000 hrs or 2400 starts

Criterion is Hours or Starts (Whichever Occurs First)

Factors Impacting Maintenance

Hours Factors

• Fuel	Gas	1
	Distillate	1.5
	Crude	2 to 3
	Residual	3 to 4
• Peak Load		
• Water/Steam	Injection	
	Dry Control	1 (GTD-222)
	Wet Control	1.9 (5% H_2O GTD-222)

Starts Factors

• Trip from Full Load	8
• Fast Load	2
• Emergency Start	20

Figure 9. Maintenance factors – hot gas path (buckets and nozzles)

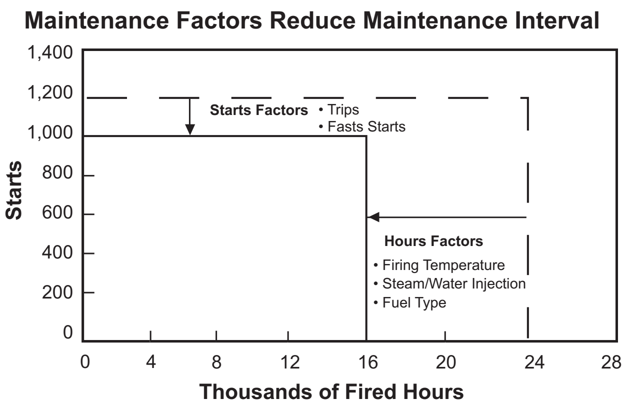


Figure 10. GE maintenance interval for hot-gas inspections

have a maintenance factor ranging from three to four for residual fuel and two to three for crude oil fuels. These fuels generally release a higher amount of radiant thermal energy, which results in a subsequent reduction in combustion hardware life, and frequently contain corrosive elements such as sodium, potassium, vanadium and lead that can lead to accelerated hot corrosion of turbine nozzles and buckets. In addition, some elements in these fuels can cause deposits either directly or through compounds formed with inhibitors that are used to prevent corrosion. These deposits impact performance and can lead to a need for more frequent maintenance.

Distillates, as refined, do not generally contain high levels of these corrosive elements, but harmful contaminants can be present in these fuels when delivered to the site. Two common ways of contaminating number two distillate fuel oil are: salt water ballast mixing with the cargo during sea transport, and contamination of the distillate fuel when transported to site in tankers, tank trucks or pipelines that were previously used to transport contaminated fuel, chemicals or leaded gasoline. From *Figure 11*, it can be seen that GE's experience with distillate fuels indicates that the hot gas path maintenance factor can range from as low as one

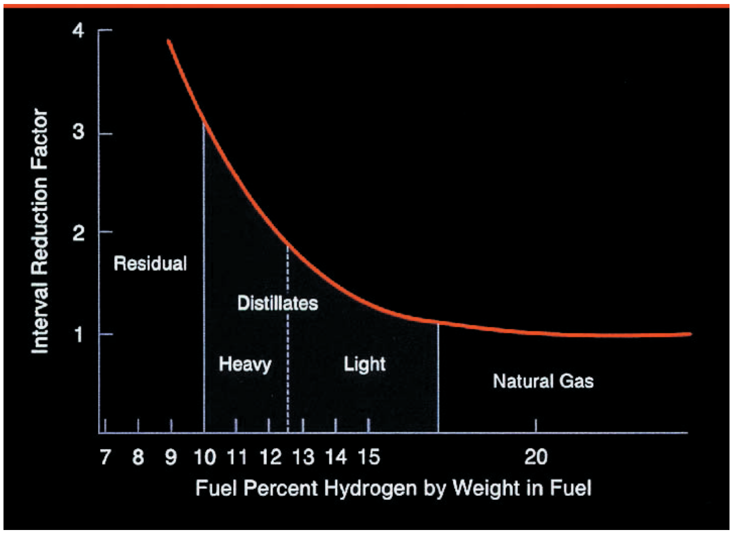


Figure 11. Estimated effect of fuel type on maintenance

(equivalent to natural gas) to as high as three. Unless operating experience suggests otherwise, it is recommended that a hot gas path maintenance factor of 1.5 be used for operation on distillate oil. Note also that contaminants in liquid fuels can affect the life of gas turbine auxiliary components such as fuel pumps and flow dividers.

As shown in *Figure 11*, gas fuels, which meet GE specifications, are considered the optimum fuel with regard to turbine maintenance and are assigned no negative impact. The importance of proper fuel quality has been amplified with Dry Low NO_X (DLN) combustion systems. Proper adherence to GE fuel specifications in GEI-41040 and GEI-41047 is required to allow proper combustion system operation, and to maintain applicable warranties. Liquid hydrocarbon carryover can expose the hot gas path hardware to severe overtemperature conditions and can result in significant reductions in hot gas path parts lives or repair intervals. Owners can control this potential issue by using effective gas scrubber systems and by superheating the gaseous fuel prior to use to provide a nominal 50°F (28°C) of superheat at the turbine gas control valve connection. Integral to the system, coalescing filters installed upstream of the performance gas heaters is a best practice and ensures the most efficient removal of liquids and vapor phase constituents.

The prevention of hot corrosion of the turbine buckets and nozzles is mainly under the control of the owner. Undetected and untreated, a single shipment of contaminated fuel can cause substantial damage to the gas turbine hot gas path components. Potentially high maintenance costs and loss of availability can be minimized or eliminated by:

- Placing a proper fuel specification on the fuel supplier. For liquid fuels, each shipment should include a report that identifies specific gravity, flash point, viscosity, sulfur content, pour point and ash content of the fuel.
- Providing a regular fuel quality sampling and analysis program. As part of this program, an online water in fuel oil monitor is recommended, as is a portable fuel analyzer that, as a minimum, reads vanadium, lead, sodium, potassium, calcium and magnesium.
- Providing proper maintenance of the fuel treatment system when burning heavier fuel oils and by providing cleanup equipment for distillate fuels when there is a potential for contamination.

In addition to their presence in the fuel, contaminants can also enter the turbine via the inlet air and from the steam or water injected for NO_X emission control or power augmentation. Carryover from evaporative coolers is another source of contaminants. In some cases, these sources of contaminants have been found to cause hot-gas-path degradation equal to that seen with fuel-related contaminants.GE specifications define limits for maximum concentrations of contaminants for fuel, air and steam/water.

In addition to fuel quality, fuel system operation is also a factor in equipment maintenance. Liquid fuel may remain unpurged and in contact with hot combustion components after shutdown, as well as stagnate in the fuel system when strictly gas fuel is run for an extended time. To minimize varnish and coke accumulation, dual fuel units (gas and liquid capable) should be shut down running gas fuel whenever possible. Likewise, during extended operation on gas, regular transfers from gas to liquid are recommended to exercise the system components and minimize coking.

Contamination and build-up may prevent the system from removing fuel oil and other liquids from the combustion, compressor discharge, turbine, and exhaust sections when the unit is shutdown or during startup. Liquid fuel oil trapped in the system piping also creates a safety risk. Correct functioning of the false start drain system (FSDS) should be ensured through proper maintenance and inspection per GE procedures.

Firing Temperatures

Significant operation at peak load, because of the higher operating temperatures, will require more frequent maintenance and replacement of hot-gas-path components. For an MS7001EA turbine, each hour of operation at peak load firing temperature (+100°F/56°C) is the same, from a bucket parts life standpoint, as six hours of operation at base load. This type of operation will result in a maintenance factor of six. *Figure 12* defines the parts life effect corresponding to changes in firing temperature. It should be noted that this is not a linear relationship, as a +200°F/111°C increase in firing temperature would have an equivalency of six times six, or 36:1.

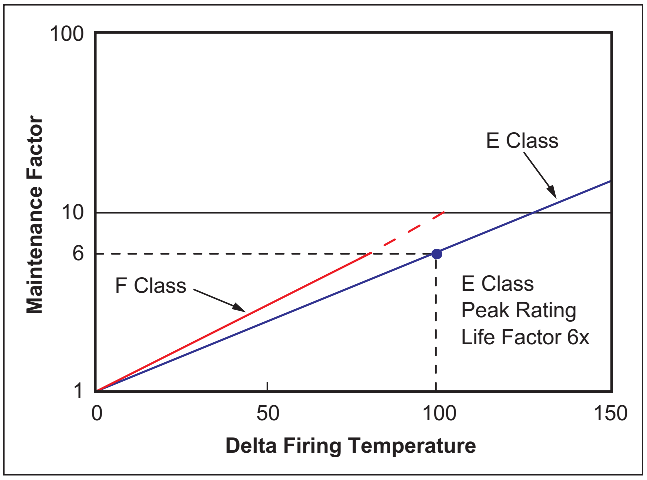


Figure 12. Bucket life firing temperature effect

Higher firing temperature reduces hot-gas-path parts lives while lower firing temperature increases parts lives. This provides an opportunity to balance the negative effects of peak load operation by periods of operation at part load. However, it is important to recognize that the nonlinear behavior described above will not result in a one for one balance for equal magnitudes of over and under firing operation. Rather, it would take six hours of operation at –100°F/56°C under base conditions to compensate for one hour operation at +100°F/56°C over base load conditions.

It is also important to recognize that a reduction in load does not always mean a reduction in firing temperature. In heat recovery applications, where steam generation drives overall plant efficiency, load is first reduced by closing variable inlet guide vanes to reduce inlet airflow while maintaining maximum exhaust temperature. For these combined cycle applications, firing temperature does not decrease until load is reduced below approximately 80% of rated output. Conversely, a turbine running in simple cycle mode maintains full open inlet guide vanes during a load reduction to 80% and will experience over a 200°F/111°C reduction in firing temperature at this output level. The hot-gas-path parts life effects for these different modes of operation are obviously quite different. This turbine control effect is illustrated in *Figure 13*. Similarly, turbines with DLN combustion systems utilize inlet guide vane turndown as well as inlet bleed heat to extend operation of low NO_X premix operation to part load conditions.

Firing temperature effects on hot gas path maintenance, as described above, relate to clean burning fuels, such as natural gas and light distillates, where creep rupture of hot gas path components is the primary life limiter and is the mechanism that determines the hot gas path maintenance interval impact. With ash-bearing heavy fuels, corrosion and deposits are the primary influence and a different

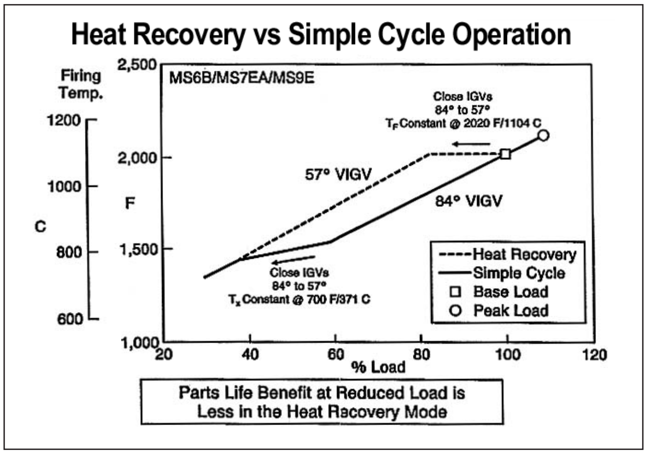


Figure 13. Firing temperature and load relationship – heat recovery vs. simple cycle operation

relationship with firing temperature exists. *Figure 14* illustrates the sensitivity of hot gas path maintenance factor to firing temperature for a heavy fuel operation. It can be seen that while the sensitivity to firing temperature is less, the maintenance factor itself is higher due to issues relating to the corrosive elements contained in these fuels.

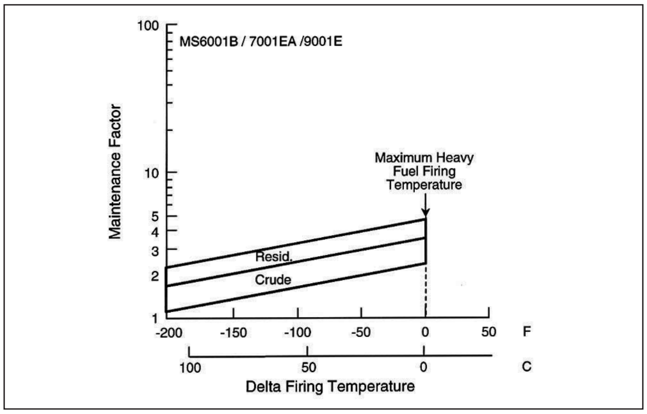


Figure 14. Heavy fuel maintenance factors

Steam/Water Injection

Water or steam injection for emissions control or power augmentation can impact parts lives and maintenance intervals even when the water or steam meets GE specifications. This relates to the effect of the added water on the hot-gas transport properties. Higher gas conductivity, in particular, increases the heat transfer to the buckets and nozzles and can lead to higher metal temperature and reduced parts life as shown in *Figure 15*.

Steam/Water Injection Increases Metal Temperature of Hot-Gas-Path Components

- Water Affects Gas Transport Properties:
  - k - Thermal Conductivity ↑
  - C_P - Specific Heat ↑
  - μ - Viscosity ↔
- This Increases Heat Transfer Coefficients:
- Which Increases Metal Temperature and Decreases Bucket Life

Example (MS7001EA Stage 1 Bucket):
3% Steam (25 ppm NO_x)
H = +4% (Heat Transfer Coefficient)
T_{Metal} = +15 F (8 C)
Life = – 33%

For Constant Firing Temperature

Figure 15. Steam/water injection and bucket/nozzle life

Parts life impact from steam or water injection is directly impacted by the way the turbine is controlled. The control system on most base load applications reduces firing temperature as water or steam is injected. This is known as dry control curve operation, which counters the effect of the higher heat transfer on the gas side, and results in no net impact on bucket life. This is the standard configuration for all gas turbines, both with and without water or steam injection. On some installations, however, the control system is designed to maintain firing temperature constant with water or steam injection level. This is known as wet control curve operation, which results in additional unit output, but decreases parts life as previously described. Units controlled in this way are generally in peaking applications where annual operating hours are low or where operators have determined that reduced parts lives are justified by the power advantage. *Figure 16* illustrates the wet and dry control curve and the performance differences that result from these two different modes of control.

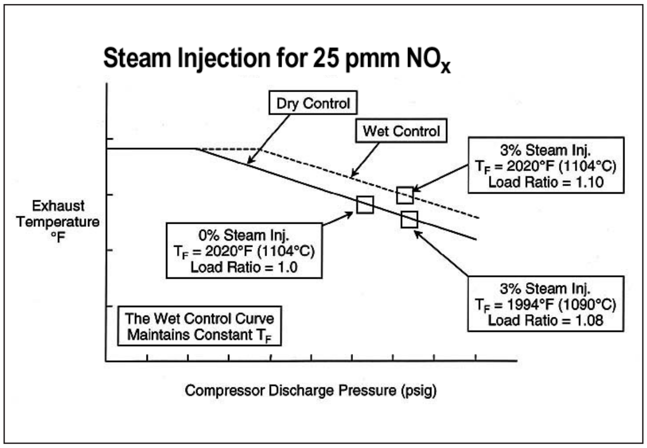


Figure 16. Exhaust temperature control curve – dry vs. wet control MS7001EA

An additional factor associated with water or steam injection relates to the higher aerodynamic loading on the turbine components that results from the injected water increasing the cycle pressure ratio. This additional loading can increase the downstream deflection rate of the second- and third-stage nozzles, which would reduce the repair interval for these components. However, the introduction of GTD-222, a new high creep strength stage two and three nozzle alloy, has minimized this factor.

Maintenance factors relating to water injection for units operating on dry control range from one (for units equipped with GTD-222 second-stage and third-stage nozzles) to a factor of 1.5 for units equipped with FSX-414 nozzles and injecting 5% water. For wet control curve operation, the maintenance factor is approximately two at 5% water injection for GTD-222 and four for FSX-414.

Cyclic Effects

In the previous discussion, operating factors that impact the hours-based maintenance criteria were described. For the starts-based maintenance criteria, operating factors associated with the cyclic effects produced during startup, operation and shutdown of the turbine must be considered. Operating conditions other than the standard startup and shutdown sequence can potentially reduce the cyclic life of the hot gas path components and rotors, and, if present, will require more frequent maintenance and parts refurbishment and/or replacement.

Hot Gas Path Parts

Figure 17 illustrates the firing temperature changes occurring over a normal startup and shutdown cycle. Light-off, acceleration, loading, unloading and shutdown all produce gas temperature changes that produce corresponding metal temperature changes. For rapid changes in gas temperature, the edges of the bucket or nozzle respond more quickly than the thicker bulk section, as pictured in *Figure 18*. These gradients, in turn, produce thermal stresses that, when cycled, can eventually lead to cracking. *Figure 19* describes the temperature strain history of an MS7001EA stage 1 bucket during a normal startup and shutdown cycle. Light-off and acceleration produce transient compressive strains in the bucket as the fast responding leading edge heats up more quickly than the thicker bulk section of the airfoil. At full load conditions, the bucket reaches its maximum metal temperature and a compressive strain produced from the normal steady state temperature gradients that exist in the cooled part. At shutdown, the conditions reverse where the faster responding edges cool more quickly than the bulk section, which results in a tensile strain at the leading edge.

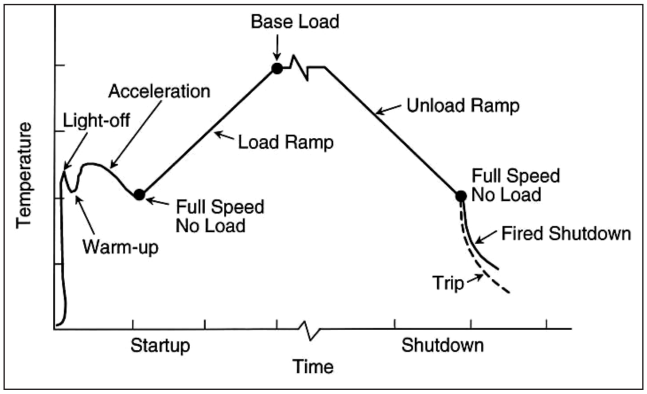


Figure 17. Turbine start/stop cycle – firing temperature changes

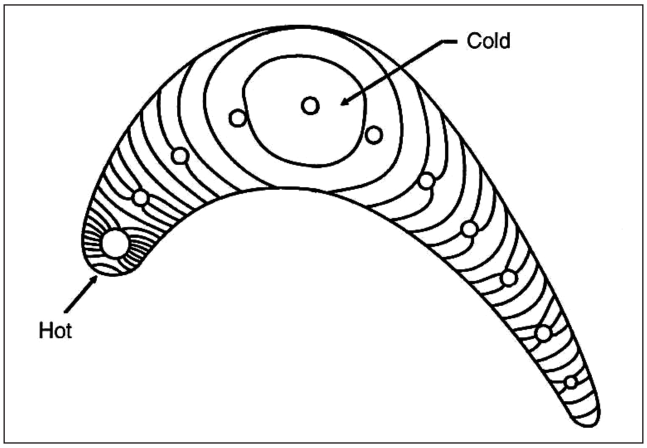


Figure 18. First stage bucket transient temperature distribution

Thermal mechanical fatigue testing has found that the number of cycles that a part can withstand before cracking occurs is strongly influenced by the total strain range and the maximum metal temperature experienced. Any operating condition that significantly increases the strain range and/or the maximum metal temperature over the normal cycle conditions will act to reduce the fatigue life and increase the starts-based maintenance factor. For example, *Figure 20*

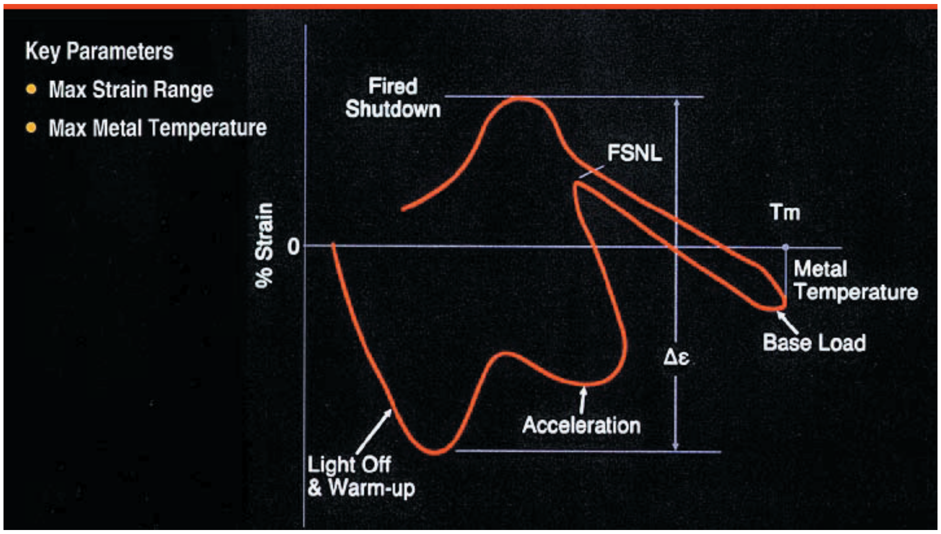


Figure 19. Bucket low cycle fatigue (LCF)

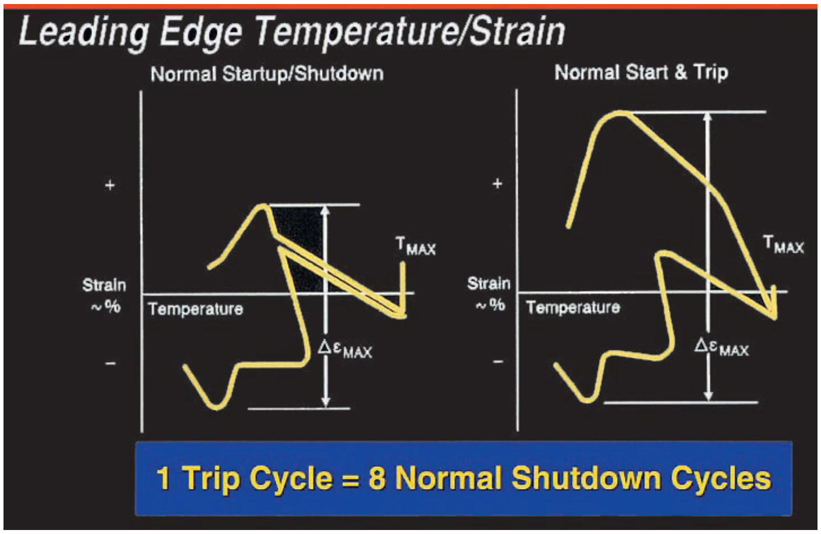


Figure 20. Low cycle fatigue life sensitivities – first stage bucket

compares a normal operating cycle with one that includes a trip from full load. The significant increase in the strain range for a trip cycle results in a life effect that equates to eight normal start/stop cycles, as shown. Trips from part load will have a reduced impact because of the lower metal temperatures at the initiation of the trip event. *Figure 21* illustrates that while a trip from between 80% and 100% load has an 8:1 maintenance factor, a trip from full speed no load has a maintenance factor of 2:1. Similarly, overfiring of the unit during peak load operation leads to increased component metal temperatures.

As a result, a trip from peak load has a maintenance factor of 10:1. Trips are to be assessed in addition to the regular startup/shutdown cycles (as starts adders). As such, in the factored starts equation of *Figure 44*, one is subtracted from the severity factor so that the net result of the formula (*Figure 44*) is the same as that dictated by the increased strain range. For example, a startup and trip from base load would count as eight total cycles (one cycle for startup to base load plus 8-1=7 cycles for trip from base load), just as indicated by the 8:1 maintenance factor.

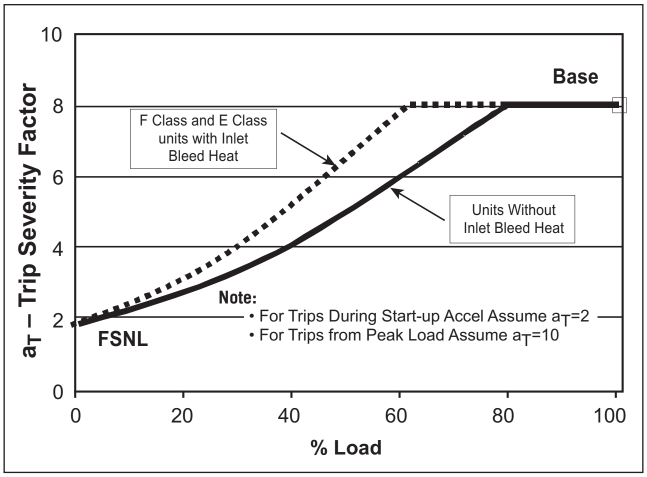


Figure 21. Maintenance factor – trips from load

Similarly to trips from load, emergency starts and fast loading will impact the starts-based maintenance interval. This again relates to the increased strain range that is associated with these events. Emergency starts where units are brought from standstill to full load in less than five minutes will have a parts life effect equal to 20 additional cycles and a normal start with fast loading will have a parts life effect equal to 2 additional cycles. Like trips, the effects of a fast start or fast loading on the machine are considered separate from a normal cycle and their effects must be tabulated in addition to the normal start/stop cycle. However, there is no -1 applied to these factors, so an emergency start to base load would have a total impact of 21 cycles. Refer to Appendix A for factored starts examples.

While the factors described above will decrease the starts-based maintenance interval, part load operating cycles would allow for an extension of the maintenance interval. *Figure 22* is a guideline that could be used in considering this type of operation. For example, two operating cycles to maximum load levels of less than 60% would equate to one start to a load greater than 60% or, stated another way, would have a maintenance factor of 5. Factored starts calculations are based upon the maximum load achieved during operation. Therefore, if a unit is operated at part load for three weeks, and then ramped up to base load for the last ten minutes, then the unit's total operation would be described as a base load start/stop cycle.

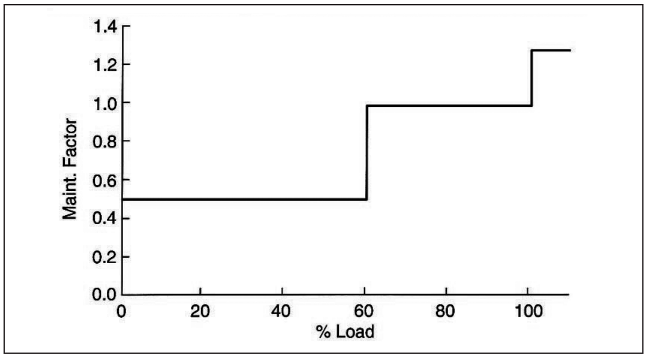


Figure 22. Maintenance factor – effect of start cycle maximum load level

Rotor Parts

In addition to the hot gas path components, the rotor structure maintenance and refurbishment requirements are impacted by the cyclic effects associated with startup, operation and shutdown, as well as loading and off-load characteristics. Maintenance factors specific to an application's operating profile and rotor design must be determined and incorporated into the operators maintenance planning. Disassembly and inspection of all rotor components is required when the accumulated rotor starts or hours reach the inspection limit. (See *Figure 45* and *Figure 46* in the Inspection Intervals Section.)

For the rotor, the thermal condition when the start-up sequence is initiated is a major factor in determining the rotor maintenance interval and individual rotor component life. Rotors that are cold when the startup commences develop transient thermal stresses as the turbine is brought on line. Large rotors with their longer thermal time constants develop higher thermal stresses than smaller rotors undergoing the same startup time sequence. High thermal stresses will reduce thermal mechanical fatigue life and the age for inspection.

The steam turbine industry recognized the need to adjust startup times in the 1950 to 1970 time period when power generation market growth led to larger and larger steam turbines operating at higher temperatures. Similar to the steam turbine rotor size increases of the 1950s and 1960s, gas turbine rotors have seen a growth trend in the 1980s and 1990s as the technology has advanced to meet the demand for combined cycle power plants with high power density and thermal efficiency.

With these larger rotors, lessons learned from both the steam turbine experience and the more recent gas turbine experience should be factored into the start-up control for the gas turbine and/or maintenance factors should be determined for an application's duty cycle to quantify the rotor life reductions associated with different severity levels. The maintenance factors so determined are used to adjust the rotor component inspection, repair and replacement intervals that are appropriate to that particular duty cycle.

Though the concept of rotor maintenance factors is applicable to all gas turbine rotors, only F Class rotors will be discussed in detail. The rotor maintenance factor for a startup is a function of the downtime following a previous period of operation. As downtime increases, the rotor metal temperature approaches ambient conditions and thermal fatigue impact during a subsequent start-up increases. As such, cold starts are assigned a rotor maintenance factor of two and hot starts a rotor maintenance factor of less than one due to the lower thermal stress under hot conditions. This impact varies from one location in the rotor structure to another. Since the most limiting location determines the overall rotor impact, the rotor maintenance factor indicates the upper bound locus of the rotor maintenance factors at these various features.

Rotor starting thermal condition is not the only operating factor that influences rotor maintenance intervals and component life. Fast starts and fast loading, where the turbine is ramped quickly to load, increase thermal gradients and are more severe duty for the rotor. Trips from load and particularly trips followed by immediate restarts reduce the rotor maintenance interval as do hot restarts within the first hour of a hot shutdown. *Figure 23* lists recommended operating factors that should be used to determine the rotor's overall maintenance factor for PG7241 and PG9351 design rotors. The factors to be used for other models are determined by applicable Technical Information Letters.

7241/9351* Designs

	Rotor Maintenance Factors	
	Fast Start	Normal Start
Hot Start Factor (1–4 Hrs. Down)	1.0	0.5
Warm 1 Start Factor (4–20 Hrs. Down)	1.8	0.9
Warm 2 Start Factor (20–40 Hrs. Down)	2.8	1.4
Cold Start Factor (>40 Hrs. Down)	4.0	2.0
Trip from Load Factor	4.0	4.0
Hot Start Factor (0–1 Hr. Down)	4.0	2.0

*Other factors may apply to early 9351 units

- Factors Are a Function of Machine Thermal Condition at Start-Up
- Trips from Load, Fast Starts and >20-hour Restarts Reduce Maintenance Intervals

Figure 23. Operation-related maintenance factors

The significance of each of these factors to the maintenance requirements of the rotor is dependent on the type of operation that the unit sees. There are three general categories of operation that are typical of most gas turbine applications. These are peaking, cyclic and continuous duty as described below:

- Peaking units have a relatively high starting frequency and a low number of hours per start. Operation follows a seasonal demand. Peaking units will generally see a high percentage of cold starts.

- Cyclic duty units start daily with weekend shutdowns. Twelve to sixteen hours per start is typical which results in a warm rotor condition for a large percentage of the starts. Cold starts are generally seen only following a startup after a maintenance outage or following a two day weekend outage.
- Continuous duty applications see a high number of hours per start and most starts are cold because outages are generally maintenance driven. While the percentage of cold starts is high, the total number of starts is low. The rotor maintenance interval on continuous duty units will be determined by service hours rather than starts.

Figure 24 lists operating profiles on the high end of each of these three general categories of gas turbine applications.

As can be seen in *Figure 24*, these duty cycles have different combinations of hot, warm and cold starts with each starting condition having a different impact on rotor maintenance interval as previously discussed. As a result, the starts based rotor maintenance interval will depend on an applications specific duty cycle. In a later section, a method will be described that allows the turbine operator to determine a maintenance factor that is specific to the operation's duty cycle. The application's integrated maintenance factor uses the rotor maintenance factors described above in combination with the actual duty cycle of a specific application and can be used to determine rotor inspection intervals. In this calculation, the reference duty cycle that yields a starts based maintenance factor equal to one is defined in *Figure 25*. Duty cycles different from the *Figure 25* definition, in particular duty cycles with more cold starts, or a high number of trips, will have a maintenance factor greater than one.

Turning gear or ratchet operation after shutdown, and before starting/restarting is a crucial part of normal operating procedure. *Figure F-1* describes turning gear/ratchet scenarios and operation guidelines (*See Appendix*). Relevant operating instructions and TILs should be adhered to where applicable. After a shutdown, turning of the warm rotor is essential to avoid bow, which could lead to high vibrations and excessive rubs if a start is initiated with the rotor in a bowed condition. As a best practice, units should remain on turning gear or ratchet following a planned shutdown until wheelspace temperatures have stabilized at near ambient temperature. If the unit is to see no further activity for 48 hours after cool-down is completed, then it may be taken off of turning gear.

Peaking – Cyclic – Continuous

	Peaking	**Cyclic**	**Continuous**
Hot Start (Down <4 Hr.)	3%	1%	10%
Warm 1 Start (Down 4-20 hr.)	10%	82%	5%
Warm 2 Start (Down 20-40 Hr.)	37%	13%	5%
Cold Start (Down >40 Hr.)	50%	4%	80%
Hours/Start	4	16	400
Hours/Year	600	4800	8200
Starts per Year	150	300	21
Percent Trips	3%	1%	20%
Number of Trips per Year	5	3	4
Typical Maintenance Factor (Starts Based)	**1.7**	**1.0**	**NA**

- Operational Profile is Application Specific
- Inspection Interval is Application Specific

Figure 24. FA gas turbine typical operational profile

Baseline Unit

Cyclic Duty

6	Starts/Week	
16	Hours/Start	
4	Outage/Year Maintenance	
50	Weeks/Year	
4800	Hours/Year	
300	Starts/Year	
0	Trips/Year	
1	Maintenance Factor	
12	Cold Starts/Year (down >40 Hr.)	4%
39	Warm 2 Starts/Year (Down 20-40 Hr.)	13%
246	Warm Starts/Year (Down 4-20 Hr.)	82%
3	Hot Starts per Year	1%

Baseline Unit Achieves Maintenance Factor = 1

Figure 25. Baseline for starts-based maintenance factor definition

Further guidelines exist for hot restarts and cold starts. It is recommended that the rotor be placed on turning gear for one hour prior to restart following a trip from load, trip from full speed no load, or normal shutdown. This will allow transient thermal stresses to subside before superimposing a startup transient. If the machine must be restarted in less than one hour, then cold start factors will apply. Longer periods of turning gear operation may be necessary prior to a cold start or hot restart if the presence of bow is detected. Vibration data taken while at crank speed can be used to confirm that rotor bow is at acceptable levels and the start sequence can be initiated. Users should reference the Operation and Maintenance Manual and appropriate TILs for specific instructions and information for their units.

Combustion Parts

A typical combustion system contains transition pieces, combustion liners, flow sleeves, head-end assemblies containing fuel nozzles and cartridges, end caps and end covers, and assorted other hardware including cross-fire tubes, spark plugs and flame detectors. In addition, there can be various fuel and air delivery components such as purge or check valves and flex hoses. GE provides several types of combustion systems including standard combustors, Multi-Nozzle Quiet Combustors (MNQC), Integrated Gasification Combined Cycle (IGCC) combustors and Dry Low NO_X (DLN) combustors. Each of these combustion systems have unique operating characteristics and modes of operation with differing responses to operational variables affecting maintenance and refurbishment requirements.

The maintenance and refurbishment requirements of combustion parts are impacted by many of the same factors as hot gas path parts including start cycle, trips, fuel type and quality, firing temperature and use of steam or water injection for either emissions control or power augmentation. However, there are other factors specific to combustion systems. One of these factors is operating mode, which describes the applied fueling pattern. The use of low load operating modes at high loads can reduce the maintenance interval significantly. An example of this is the use of DLN 1 extended lean-lean mode at high loads, which results in a maintenance factor of 10. Likewise, a maintenance factor of 10 should be applied to lean-lean operation on the DLN 2.0 units. Another factor that can impact combustion system maintenance is acoustic dynamics. Acoustic dynamics are pressure oscillations generated by the combustion system, which, if high enough in magnitude, can lead to significant wear and cracking. GE practice is to tune the combustion system to levels of acoustic dynamics low enough to ensure that the maintenance practices described here are not compromised.

Combustion maintenance is performed, if required, following each combustion inspection (or repair) interval. Inspection interval guidelines are included in *Figure 42*. It is expected and recommended that intervals be modified based on specific experience. Replacement intervals are usually defined by a recommended number of combustion (or repair) intervals and are usually combustion component specific. In general, the replacement interval as a function of the number of combustion inspection intervals is reduced if the combustion inspection interval is extended. For example, a component having an 8,000 hour combustion inspection (CI) interval and a 6(CI) or 48,000 hour replacement interval would have a replacement interval of 4(CI) if the inspection interval were increased to 12,000 hours to maintain a 48,000 hour replacement interval.

For combustion parts, the base line operating conditions that result in a maintenance factor of unity are normal fired start-up and shut-down to base load on natural gas fuel without steam or water injection. Factors that increase the hours-based maintenance factor include peaking duty, distillate or heavy fuels, and steam or water injection with dry or wet control curves. Factors that increase starts-based maintenance factor include peaking duty, fuel type, steam or water injection, trips, emergency starts and fast loading.

Off-Frequency Operation

GE heavy-duty single shaft gas turbines are designed to operate over a 95% to 105% speed range. However, operation at other than rated speed has the potential to impact maintenance requirements. Depending on the industry code requirements, the specifics of the turbine design and the turbine control philosophy employed, operating conditions can result that will accelerate life consumption of hot gas path components. Where this is true, the maintenance factor associated with this operation must be understood and these speed events analyzed and recorded so as to include in the maintenance plan for this gas turbine installation.

Generator drive turbines operating in a power system grid are sometimes required to meet operational requirements that are aimed at maintaining grid stability under conditions of sudden load or capacity changes. Most codes require turbines to remain on line in the event of a frequency disturbance. For under-frequency operation, the turbine output decrease that will normally occur with a speed decrease is allowed and the net impact on the turbine as measured by a maintenance factor is minimal. In some grid systems, there are more stringent codes that require remaining on line while maintaining load on a defined schedule of load versus grid frequency. One example of a more stringent requirement is defined by the National Grid Company (NGC). In the NGC code, conditions under which frequency excursions must be tolerated and/or controlled are defined as shown in *Figure 26*.

With this specification, load must be maintained constant over a frequency range of +/- 1% (+/- 0.5Hz in a 50 Hz grid system) with a one percent load reduction allowed for every additional one percent frequency drop down to a minimum 94% speed. Requirements stipulate that operation between 95% to 104% speed can be continuous but operation between 94% and 95% is limited to 20 seconds for each event. These conditions must be met up to a maximum ambient temperature of 25°C (77°F).

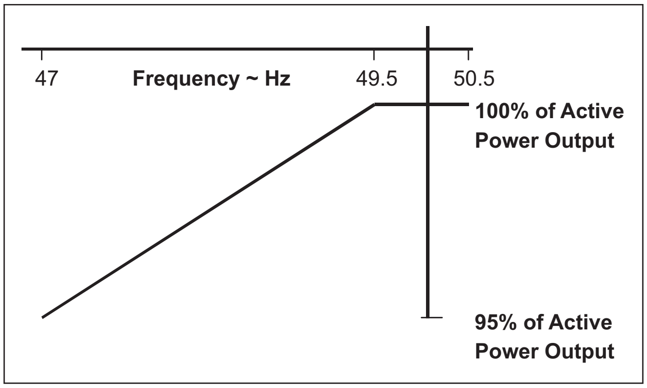


Figure 26. The NGC requirement for output versus frequency capability over all ambients less than 25°C (77°F)

Under-frequency operation impacts maintenance to the degree that nominally controlled turbine output must be exceeded in order to meet the specification defined output requirement. As speed decreases, the compressor airflow decreases, reducing turbine output. If this normal output fall-off with speed results in loads less than the defined minimum, power augmentation must be applied. Turbine overfiring is the most obvious augmentation option but other means such as utilizing gas turbine water wash have some potential as an augmentation action.

Ambient temperature can be a significant factor in the level of power augmentation required. This relates to compressor operating margin that may require inlet guide vane closure if compressor corrected speed reaches limiting conditions. For an FA class turbine, operation at 0°C (32°F) would require no power augmentation to meet NGC requirements while operation at 25°C (77°F) would fall below NGC requirements without a substantial amount of power augmentation. As an example, *Figure 27* illustrates the output trend at 25°C (77°F) for an FA class gas turbine as grid system frequency changes and where no power augmentation is applied.

In *Figure 27*, the gas turbine output shortfall at the low frequency end (47.5 Hz) of the NGC continuous operation compliance range would require a 160°F increase over base load firing temperature to be in compliance. At this level of over-fire, a maintenance factor exceeding 100x would be applied to all time spent at these conditions. Overfiring at this level would have implications on combustion operability and emissions compliance as well as have major impact on hot gas path parts life. An alternative power augmentation approach that has been utilized in FA gas turbines for NGC code compliance utilizes water wash in combination with increased firing temperature. As shown in *Figure 28*, with water wash on, 50°F overfiring is required to meet NGC code for operating conditions of 25°C (77°F) ambient temperature and grid frequency at 47.5 Hz. Under these conditions, the hours-based maintenance factor would be 3x as determined by *Figure 12*. It is important to understand that operation at over-frequency conditions will not trade one-for-one for periods at under-frequency conditions. As was discussed in the firing temperature section above, operation at peak firing conditions has a nonlinear logarithmic relationship with maintenance factor.

As described above, the NGC code limits operation to 20 seconds per event at an under-frequency condition between 94% to 95% speed. Grid events that expose the gas turbine to frequencies below the minimum continuous speed of 95% introduce additional maintenance and parts replacement considerations. Operation at speeds less than 95% requires increased over-fire to achieve compliance, but also introduces an additional concern that relates to the potential exposure of the blading to excitations that could result in blade resonant response and reduced fatigue life. Considering this potential, a starts-based maintenance factor of 60x is assigned to every 20 seconds of excursion for grid frequencies less than 95% speed.

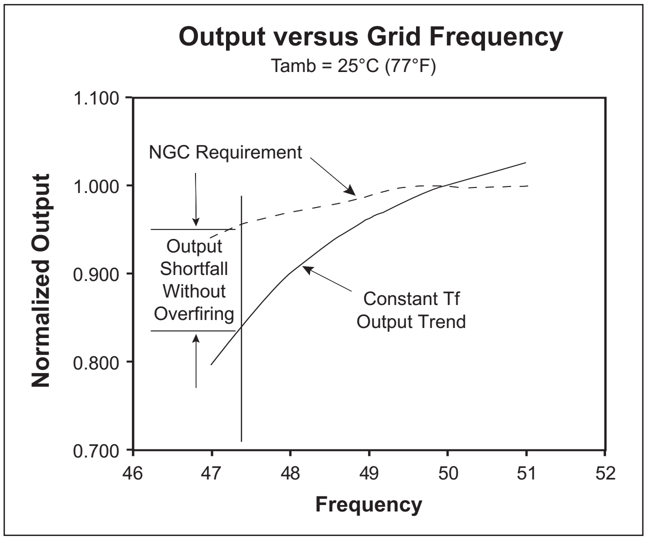


Figure 27. Turbine output at under-frequency conditions

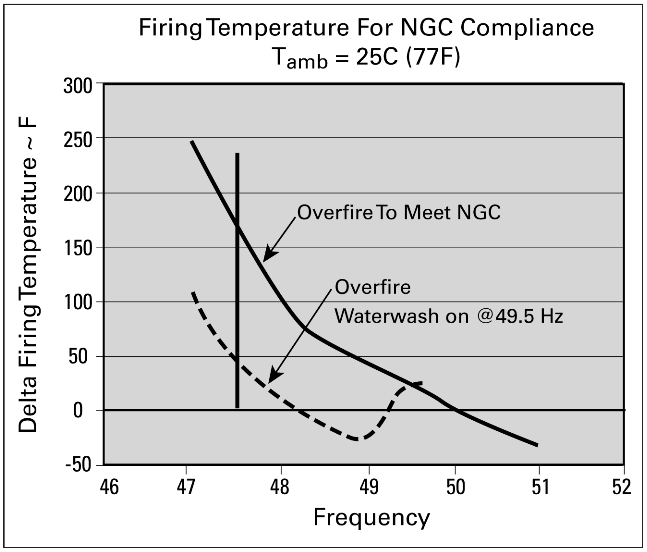


Figure 28. NGC code compliance TF required – FA class

Over-frequency or high speed operation can also introduce conditions that impact turbine maintenance and part replacement intervals. If speed is increased above the nominal rated speed, the rotating components see an increase in mechanical stress proportional to the square of the speed increase. If firing temperature is held constant at the overspeed condition, the life consumption rate of hot gas path rotating components will increase as illustrated in *Figure 29* where one hour of operation at 105% speed is equivalent to two hours at rated speed.

If overspeed operation represents a small fraction of a turbine's operating profile, this effect on parts life can sometimes be ignored. However, if significant operation at overspeed is expected and rated firing temperature is maintained, the accumulated hours must be recorded and included in the calculation of the turbine's overall maintenance factor and the maintenance schedule adjusted to reflect the overspeed operation. An option that mitigates this effect is to under fire to a level that balances the overspeed parts life effect. Some mechanical drive applications have employed that strategy to avoid a maintenance factor increase.

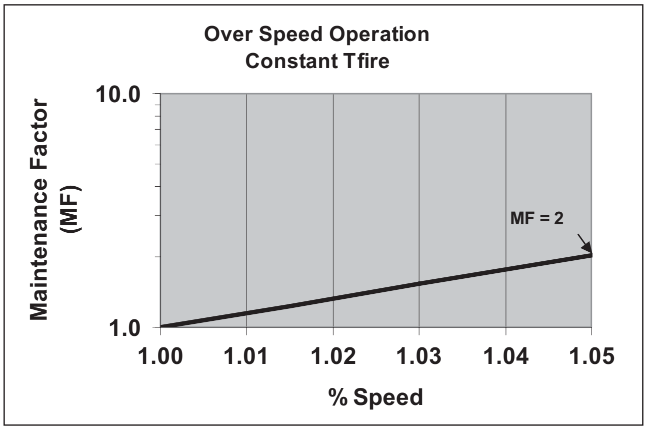


Figure 29. Maintenance factor for overspeed operation ~constant T_F

The frequency-sensitive discussion above describes code requirements related to turbine output capability versus grid frequency, where maintenance factors within the continuous operating speed range are hours-based. There are other considerations related to turbines operating in grid frequency regulation mode. In frequency regulation mode, turbines are dispatched to operate at less than full load and stand ready to respond to a frequency disturbance by rapidly picking up load. NGC requirements for units in frequency regulation mode include being equipped with a fast-acting proportional speed governor operating with an overall speed droop of 3-5%. With this control, a gas turbine will provide a load increase that is proportional to the size of the grid frequency change. For example, a turbine operating with five percent droop would pick up 20% load in response to a .5 Hz (1%) grid frequency drop.

The rate at which the turbine picks up load in response to an under-frequency condition is determined by the gas turbine design and the response of the fuel and compressor airflow control systems, but would typically yield a less than ten-second turbine response to a step change in grid frequency. Any maintenance factor associated with this operation depends on the magnitude of the load change that occurs. A turbine dispatched at 50% load that responded to a 2% frequency drop would have parts life and maintenance impact on the hot gas path as well as the rotor structure. More typically, however, turbines are dispatched at closer to rated load where maintenance factor effects may be less severe. The NGC requires 10% plant output in 10 seconds in response to a .5 Hz (1%) under frequency condition. In a combined cycle installation where the gas turbine alone must pick up the transient loading, a load change of 15% in 10 seconds would be required to meet that requirement. Maintenance factor effects related to this would be minimal for the hot gas path but would impact the rotor maintenance factor. For an FA class rotor, each frequency excursion would be counted as an additional factored start in the numerator of the maintenance factor calculation described in *Figure 45*. A further requirement for the rotor is that it must be in hot running condition prior to being dispatched in frequency regulation mode.

Air Quality

Maintenance and operating costs are also influenced by the quality of the air that the turbine consumes. In addition to the deleterious effects of airborne contaminants on hot-gas-path components, contaminants such as dust, salt and oil can also cause compressor blade erosion, corrosion and fouling. Twenty-micron particles entering the compressor can cause significant blade erosion.

Fouling can be caused by submicron dirt particles entering the compressor as well as from ingestion of oil vapor, smoke, sea salt and industrial vapors.

Corrosion of compressor blading causes pitting of the blade surface, which, in addition to increasing the surface roughness, also serves as potential sites for fatigue crack initiation. These surface roughness and blade contour changes will decrease compressor airflow and efficiency, which in turn reduces the gas turbine output and overall thermal efficiency.

Generally, axial flow compressor deterioration is the major cause of loss in gas turbine output and efficiency. Recoverable losses, attributable to compressor blade fouling, typically account for 70 to 85 percent of the performance losses seen. As *Figure 30* illustrates, compressor fouling to the extent that airflow is reduced by 5%, will reduce output by 13% and increase heat rate by 5.5%. Fortunately, much can be done through proper operation and maintenance procedures to minimize fouling type losses. On-line compressor wash systems are available that are used to maintain compressor efficiency by washing the compressor while at load, before significant fouling has occurred. Off-line systems are used to clean heavily fouled compressors. Other procedures include maintaining the inlet filtration system and inlet evaporative coolers as well as periodic inspection and prompt repair of compressor blading.

There are also non-recoverable losses. In the compressor, these are typically caused by nondeposit-related blade surface roughness, erosion and blade tip rubs. In the turbine, nozzle throat area changes, bucket tip clearance increases and leakages are potential causes. Some degree of unrecoverable performance degradation should be expected, even on a well-maintained gas turbine.

The owner, by regularly monitoring and recording unit performance parameters, has a very valuable tool for diagnosing possible compressor deterioration.

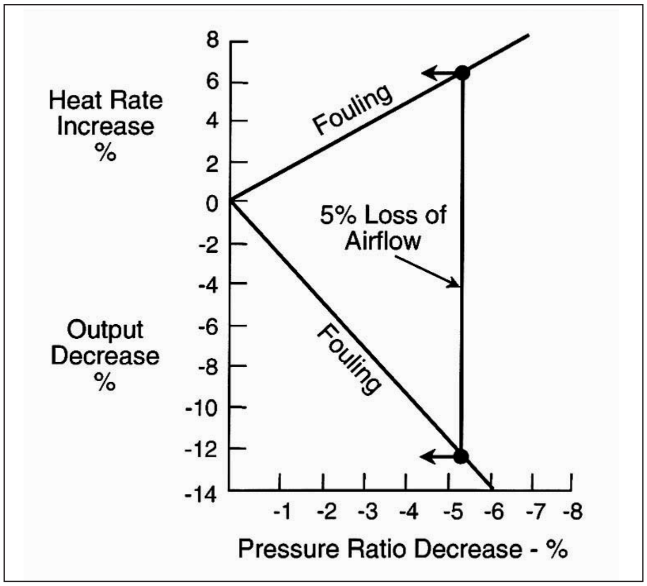


Figure 30. Deterioration of gas turbine performance due to compressor blade fouling

Lube Oil Cleanliness

Contaminated or deteriorated lube oil can cause wear and damage on bearing Babbitt surfaces. This can lead to extended outages and costly repairs. Routine sampling of the turbine lube oil for proper viscosity, chemical composition and contamination is an essential part of a complete maintenance plan.

Lube oil should be sampled and tested per GEK-32568, “Lubricating Oil Recommendations for Gas Turbines with Bearing Ambients Above 500°F (260°C).” Additionally, lube oil should be checked periodically for particulate and water contamination as outlined in GEK-110483, “Cleanliness Requirements for Power Plant Installation, Commissioning and Maintenance.” At a minimum, the lube oil should be sampled on a quarterly basis; however, monthly sampling is recommended.

Moisture Intake

One of the ways some users increase turbine output is through the use of inlet foggers. Foggers inject a large amount of moisture in the inlet ducting, exposing the forward stages of the compressor to potential water carry-over. Operation of a compressor in such an environment may lead to long-term degradation of the compressor due to corrosion and erosion, fouling, and material property degradation. Experience has shown that depending on the quality of water used, the inlet silencer and ducting material, and the condition of the inlet silencer, fouling of the compressor can be severe with inlet foggers. Similarly, carry-over from evaporative coolers and excessive water washing can degrade the compressor. *Figure 31* shows the long-term material property degradation resulting from operating the compressor in a wet environment. The water quality standard that should be adhered to is found in GEK-101944B, "Requirements for Water/Steam Purity in Gas Turbines."

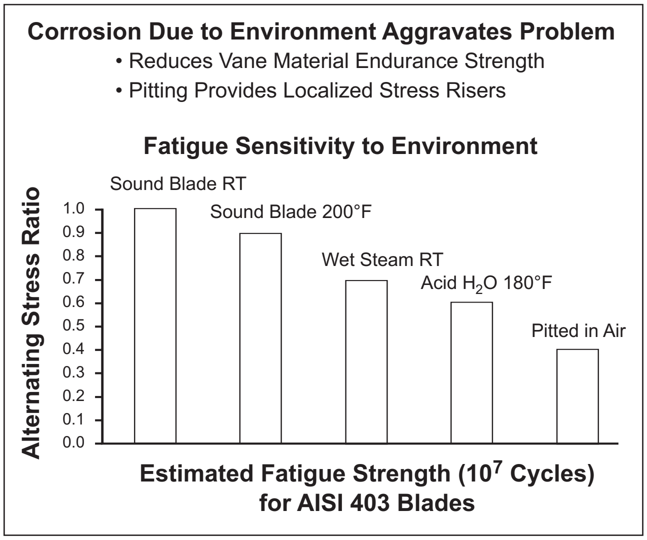


Figure 31. Long term material property degradation in a wet environment

For turbines with 403SS compressor blades, the presence of water carry-over will reduce blade fatigue strength by as much as 30% and increases the crack propagation rate in a blade if a flaw is present. The carry-over also subjects the blades to corrosion. Such corrosion might be accelerated by a saline environment (*see GER-3419*). Further reductions in fatigue strength will result if the environment is acidic and if pitting is present on the blade. Pitting is corrosion-induced and blades with pitting can see material strength reduced to 40% of its virgin value. This condition is surplused by downtime in humid environments, affecting wet corrosion.

Uncoated GTD-450 material is relatively resistant to corrosion while uncoated 403SS is quite susceptible. Relative susceptibility of various compressor blade materials and coatings is shown in *Figure 32*. As noted in GER-3569F, Al coatings are susceptible to erosion damage leading to unprotected sections of the blade. Because of this, the GECC-1 coating was created to combine the effects of an Al coating to prevent corrosion and a ceramic topcoat to prevent erosion.

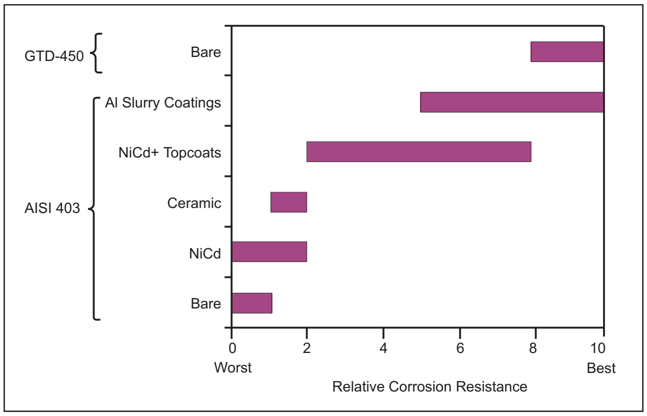


Figure 32. Susceptibility of compressor blade materials and coatings

Water droplets will cause leading edge erosion on the first few stages of the compressor. This erosion, if sufficiently developed, may lead to blade failure. Additionally, the roughened leading edge surface lowers the compressor efficiency and unit performance.

Utilization of inlet fogging or evaporative cooling may also introduce water carry-over or water ingestion into the compressor, resulting in R0 erosion. Although the design intent of evaporative coolers and inlet foggers should be to fully vaporize all cooling water prior to its ingestion into the compressor, evidence suggests that, on systems that were not properly commissioned, the water may not be fully vaporized (e.g., streaking discoloration on the inlet duct or bell mouth). If this is the case, then the unit should be inspected and maintained per instruction, as presented in applicable TILs.

MAINTENANCE INSPECTIONS

Maintenance inspection types may be broadly classified as standby, running and disassembly inspections. The standby inspection is performed during off-peak periods when the unit is not operating and includes routine servicing of accessory systems and device calibration. The running inspection is performed by observing key operating parameters while the turbine is running. The disassembly inspection requires opening the turbine for inspection of internal components and is performed in varying degrees. Disassembly inspections progress from the combustion inspection to the hot gas path inspection to the major inspection as shown in *Figure 33*. Details of each of these inspections are described below.

Standby Inspections

Standby inspections are performed on all gas turbines but pertain particularly to gas turbines used in peaking and intermittent-duty service where starting reliability is of primary concern. This inspection includes routinely servicing the battery system, changing filters, checking oil and water levels, cleaning relays and checking device calibrations. Servicing can be performed in off-peak periods without interrupting the availability of the turbine. A periodic startup test run is an essential part of the standby inspection.

The Operations and Maintenance Manual, as well as the Service Manual Instruction Books, contain information and drawings necessary to perform these periodic checks. Among the most useful drawings in the Service Manual Instruction Books for standby maintenance are the control specifications, piping schematic and electrical elementaries. These drawings provide the calibrations, operating limits, operating characteristics and sequencing of all control devices. This information should be used regularly by operating and maintenance personnel. Careful adherence to minor standby inspection maintenance can have a significant effect on reducing overall maintenance costs and maintaining high turbine reliability. It is essential that a good record be kept of all inspections made and of the maintenance work performed in order to ensure establishing a sound maintenance program.

Running Inspections

Running inspections consist of the general and continued observations made while a unit is operating. This starts by establishing baseline operating data during initial startup of a new unit and after any major disassembly work. This baseline then serves as a reference from which subsequent unit deterioration can be measured.

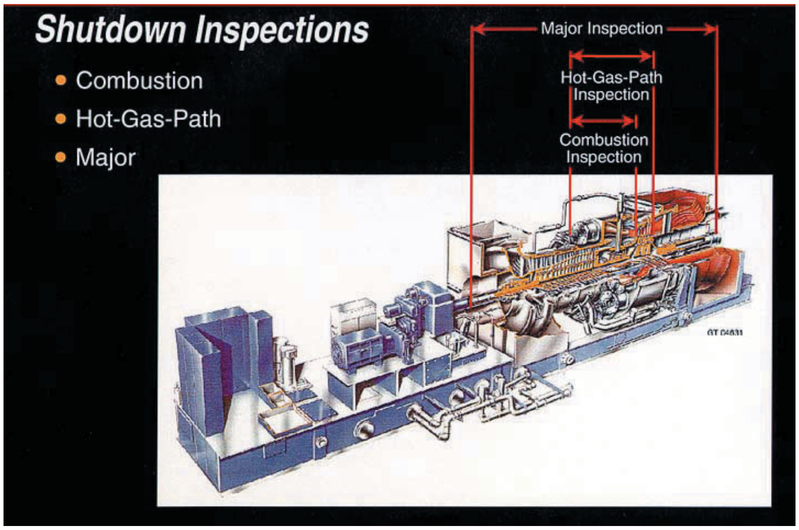


Figure 33. MS7001EA heavy-duty gas turbine – shutdown inspections

Data should be taken to establish normal equipment start-up parameters as well as key steady state operating parameters. Steady state is defined as conditions at which no more than a 5°F/3°C change in wheelspace temperature occurs over a 15-minute time period. Data must be taken at regular intervals and should be recorded to permit an evaluation of the turbine performance and maintenance requirements as a function of operating time. This operating inspection data, summarized in *Figure 34*, includes: load versus exhaust temperature, vibration, fuel flow and pressure, bearing metal temperature, lube oil pressure, exhaust gas temperatures, exhaust temperature spread variation and startup time. This list is only a minimum and other parameters should be used as necessary. A graph of these parameters will help provide a basis for judging the conditions of the system. Deviations from the norm help pinpoint impending trouble, changes in calibration or damaged components.

Load vs. Exhaust Temperature

The general relationship between load and exhaust temperature should be observed and compared to previous data. Ambient temperature and barometric pressure will have some effect upon the absolute temperature level. High exhaust temperature can be an indicator of deterioration of internal parts, excessive leaks or a fouled air compressor. For mechanical drive applications, it may also be an indication of increased power required by the driven equipment.

Vibration Level

The vibration signature of the unit should be observed and recorded. Minor changes will occur with changes in operating conditions. However, large changes or a continuously increasing trend give indications of the need to apply corrective action.

Fuel Flow and Pressure

The fuel system should be observed for the general fuel flow versus load relationship. Fuel pressures through the system should be observed. Changes in fuel pressure can indicate the fuel nozzle passages are plugged, or that fuel metering elements are damaged or out of calibration.

Exhaust Temperature and Spread Variation

The most important control function to be observed is the exhaust temperature fuel override system and the back-up over temperature trip system. Routine verification of the operation and calibration of these functions will minimize wear on the hot-gas-path parts.

- Speed
- Load
- Fired Starts
- Fired Hours
- Site Barometric Reading
- Temperatures
  - Inlet Ambient
  - Compressor Discharge
  - Turbine Exhaust
  - Turbine Wheelspace
  - Lube Oil Header
  - Lube Oil Tank
  - Bearing Metal
  - Bearing Drains
  - Exhaust Spread
- Pressures
  - Compressor Discharge
  - Lube Pump(s)
  - Bearing Header
  - Cooling Water
  - Fuel
  - Filters (Fuel, Lube, Inlet Air)
- Vibration Data for Power Train
- Generator
  - Output Voltage
  - Phase Current
  - VARS
  - Load
  - Field Voltage
  - Field Current
  - Stator Temp.
  - Vibration
- Start-Up Time
- Coast-Down Time

Figure 34. Operating inspection data parameters

The variations in turbine exhaust temperature spread should be measured and monitored on a regular basis. Large changes or a continuously increasing trend in exhaust temperature spread indicate combustion system deterioration or fuel distribution problems. If the problem is not corrected, the life of downstream hot-gas-path parts will be reduced.

Start-Up Time

Start-up time is an excellent reference against which subsequent operating parameters can be compared and evaluated. A curve of the starting parameters of speed, fuel signal, exhaust temperature and critical sequence bench marks versus time from the initial start signal will provide a good indication of the condition of the control system. Deviations from normal conditions help pinpoint impending trouble, changes in calibration or damaged components.

Coast-Down Time

Coast-down time is an excellent indicator of bearing alignment and bearing condition. The time period from when the fuel is shut off on a normal shutdown until the rotor comes to turning gear speed can be compared and evaluated.

Close observation and monitoring of these operating parameters will serve as the basis for effectively planning maintenance work and material requirements needed for subsequent shutdown periods.

Rapid Cool-Down

Prior to an inspection, it may be necessary to force cool the unit to speed the cool-down process and shorten outage time. Force cooling involves turning the unit at crank speed for an extended period of time to continue flowing ambient air through the machine. This is permitted, although a natural cool-down cycle on turning gear or ratchet is preferred for normal shutdowns when no outage is pending. Opening the compartment doors during any cool-down operation, however, is prohibited unless an emergency situation requires immediate compartment inspection—which requires that the doors be opened. Cool-down times should not be accelerated by opening the compartment doors or lagging panels, since uneven cooling of the outer casings may result in excessive case distortion and blade rubs that could potentially lead to tip distress if the rubs are significant.

Combustion Inspection

The combustion inspection is a relatively short disassembly shutdown inspection of fuel nozzles, liners, transition pieces, crossfire tubes and retainers, spark plug assemblies, flame detectors and combustor flow sleeves. This inspection concentrates on the combustion liners, transition pieces, fuel nozzles and end caps which are recognized as being the first to require replacement and repair in a good maintenance program. Proper inspection, maintenance and repair (*Figure 35*) of these items will contribute to a longer life of the downstream parts, such as turbine nozzles and buckets.

Figure 33 illustrates the section of an MS7001EA unit that is disassembled for a combustion inspection. The combustion liners, transition pieces and fuel nozzle assemblies should be removed and replaced with new or repaired components to minimize downtime. The removed liners, transition pieces and fuel nozzles can then be cleaned and repaired after the unit is returned to operation and be available for the next combustion inspection interval. Typical combustion inspection requirements for MS6001B/7001EA/9001E machines are:

- Inspect and identify combustion chamber components.
- Inspect and identify each crossfire tube, retainer and combustion liner.
- Inspect combustion liner for TBC spallation, wear and cracks. Inspect combustion system and discharge casing for debris and foreign objects.
- Inspect flow sleeve welds for cracking.

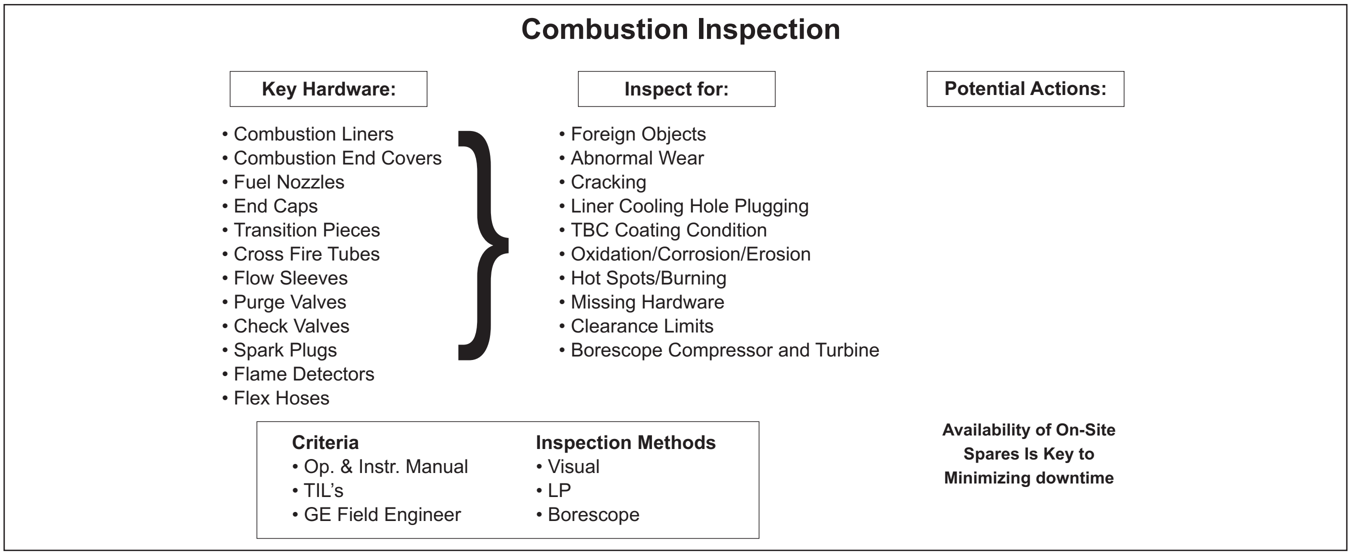


Figure 35. Combustion inspection – key elements

- Inspect transition piece for wear and cracks.
- Inspect fuel nozzles for plugging at tips, erosion of tip holes and safety lock of tips.
- Inspect all fluid, air, and gas passages in nozzle assembly for plugging, erosion, burning, etc.
- Inspect spark plug assembly for freedom from binding; check condition of electrodes and insulators.
- Replace all consumables and normal wear-and-tear items such as seals, lockplates, nuts, bolts, gaskets, etc.
- Perform visual inspection of first-stage turbine nozzle partitions and borescope inspect (*Figure 3*) turbine buckets to mark the progress of wear and deterioration of these parts. This inspection will help establish the schedule for the hot-gas-path inspection.
- Perform borescope inspection of compressor.
- Enter the combustion wrapper and observe the condition of blading in the aft end of axial-flow compressor with a borescope.
- Visually inspect the compressor inlet and turbine exhaust areas, checking condition of IGVs, IGV bushings, last-stage buckets and exhaust system components.
- Verify proper operation of purge and check valves. Confirm proper setting and calibration of the combustion controls.

After the combustion inspection is complete and the unit is returned to service, the removed combustion liners and transition pieces can be bench inspected and repaired, if necessary, by either competent on-site personnel, or off-site at a qualified GE Combustion Service Center. The removed fuel nozzles can be cleaned on-site and flow tested on-site, if suitable test facilities are available. For F Class gas turbines it is recommended that repairs and fuel nozzle flow testing be performed at qualified GE Service Centers.

Hot Gas Path Inspection

The purpose of a hot gas path inspection is to examine those parts exposed to high temperatures from the hot gases discharged from the combustion process. The hot gas path inspection outlined in *Figure 36* includes the full scope of the combustion inspection and, in addition, a detailed inspection of the turbine nozzles, stator shrouds and turbine buckets. To perform this inspection, the top half of the turbine shell must be removed. Prior to shell removal, proper machine centerline support using mechanical jacks is necessary to assure proper alignment of rotor

Hot Gas Path Inspection

Combustion Inspection Work Scope – Plus:

Key Hardware:

- Nozzles (1,2,3)
- Buckets (1,2,3)
- Stator Shrouds
- IGVs & Bushings
- Compressor Blading (Borescope)

Inspect for:

- Foreign Object Damage
- Oxidation/Corrosion/Erosion
- Cracking
- Cooling Hole Plugging
- Remaining Coating Life
- Nozzle Deflection/Distortion
- Abnormal Deflection/Distortion
- Abnormal Wear
- Missing Hardware
- Clearance Limits

Potential Actions:

Repair/Refurbishment/Replace
- Nozzles
  Weld Repair
  Reposition
  Recoat
- Buckets
  Strip & Recoat
  Weld Repair
  Blend
  Creep Life Limit
  Top Shroud Deflection

Availability of On-Site Spares Is Key to Minimizing downtime

Criteria	Inspection Methods
• Op. & Instr. Manual	• Visual
• TIL's	• LP
• GE Field Engineer	• Borescope

Figure 36. Hot gas path inspection – key elements

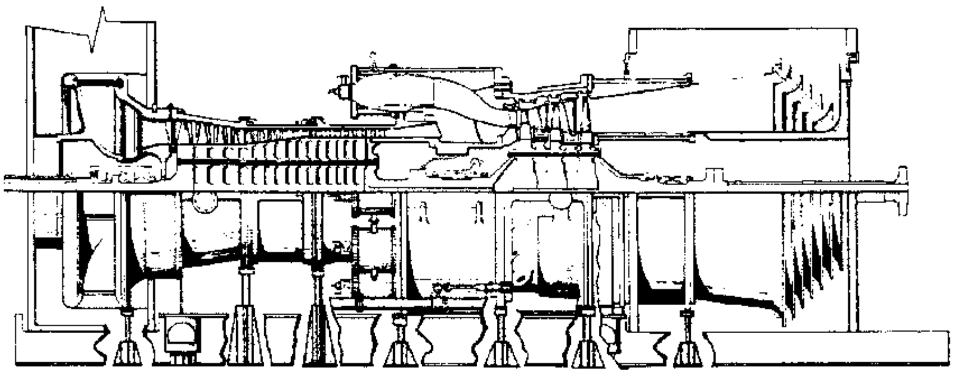


Figure 37. Stator tube jacking procedure – MS7001EA

to stator, obtain accurate half-shell clearances and prevent twisting of the stator casings. The MS7001EA jacking procedure is illustrated in *Figure 37*.

Special inspection procedures may apply to specific components in order to ensure that parts meet their intended life. These inspections may include, but are not limited to, dimensional inspections, Fluorescent Penetrant Inspection (FPI), Eddy Current Inspection (ECI) and other forms of non-destructive testing (NDT). The type of inspection required for specific hardware is determined on a part number and operational history basis, and can be attained from a service representative.

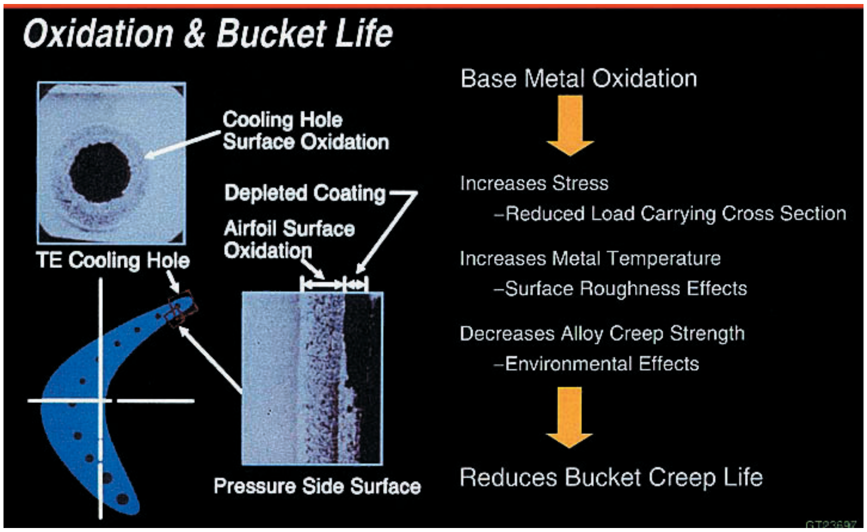
Similarly, repair action is taken on the basis of part number, unit operational history, and part condition. Repairs including (but not limited to) strip, chemical clean, HIP, heat treat, and recoat may also be necessary to ensure full parts life. Weld repair will be recommended when necessary, typically as determined by visual inspection and NDT. Failure to perform the required repairs may lead to retirement of the part before its life potential is fulfilled. In contrast, unnecessary repairs are an unneeded expenditure of time and resources. To verify the types of inspection and repair required, contact your service representative prior to an outage.

For inspection of the hot gas path (*Figure 33*), all combustion transition pieces and the first-stage turbine nozzle assemblies must be removed. Removal of the second- and third-stage turbine nozzle segment assemblies is optional, depending upon the results of visual observations, clearance measurements, and other required inspections. The buckets can usually be inspected in place. Fluorescent penetrant inspection (FPI) of the bucket vane sections may be required to detect any cracks. In addition, a complete set of internal turbine radial and axial clearances (opening and closing) must be taken during any hot gas path inspection. Re-assembly must meet clearance diagram requirements to ensure against rubs and to maintain unit performance. Typical hot gas-path inspection requirements for all machines are:

- Inspect and record condition of first-, second- and third-stage buckets. If it is determined that the turbine buckets should be removed, follow bucket removal and condition recording instructions. Buckets with protective coating should be evaluated for remaining coating life.
- Inspect and record condition of first-, second- and third-stage nozzles.
- Inspect and record condition of later-stage nozzle diaphragm packings.
- Check seals for rubs and deterioration of clearance.
- Record the bucket tip clearances.
- Inspect bucket shank seals for clearance, rubs and deterioration.
- Check the turbine stationary shrouds for clearance, cracking, erosion, oxidation, rubbing and build-up.
- Check and replace any faulty wheelspace thermocouples.
- Enter compressor inlet plenum and observe the condition of the forward section of the compressor. Pay specific attention to IGVs, looking for corrosion, bushing wear evidenced by excessive clearance and vane cracking.
- Enter the combustion wrapper and, with a borescope, observe the condition of the blading in the aft end of the axial flow compressor.
- Visually inspect the turbine exhaust area for any signs of cracking or deterioration.

The first-stage turbine nozzle assembly is exposed to the direct hot-gas discharge from the combustion process and is subjected to the highest gas temperatures in the turbine section. Such conditions frequently cause nozzle cracking and oxidation and, in fact, this is expected. The second- and third-stage nozzles are exposed to high gas bending loads, which in combination with the operating temperatures, can lead to downstream deflection and closure of critical axial clearances. To a degree, nozzle distress can be tolerated and criteria have been established for determining when repair is required. These limits are contained in the Operations and Maintenance Manuals previously described. However, as a general rule, first stage nozzles will require repair at the hot gas path inspection. The second- and third-stage nozzles may require refurbishment to re-establish the proper axial clearances. Normally, turbine nozzles can be repaired several times to extend life and it is generally repair cost versus replacement cost that dictates the replacement decision.

Coatings play a critical role in protecting the buckets operating at high metal temperatures to ensure that the full capability of the high strength superalloy is maintained and that the bucket rupture life meets design expectations. This is particularly true of cooled bucket designs that operate above 1985°F (1085°C) firing temperature. Significant exposure of the base metal to the environment will accelerate the creep rate and can lead to premature replacement through a combination of increased temperature and stress and



Oxidation & Bucket Life

Base Metal Oxidation

↓

Increases Stress
–Reduced Load Carrying Cross Section

Increases Metal Temperature
–Surface Roughness Effects

Decreases Alloy Creep Strength
–Environmental Effects

↓

Reduces Bucket Creep Life

Figure 38. Stage 1 bucket oxidation and bucket life

a reduction in material strength, as described in *Figure 38*. This degradation process is driven by oxidation of the unprotected base alloy. In the past, on early generation uncooled designs, surface degradation due to corrosion or oxidation was considered to be a performance issue and not a factor in bucket life. This is no longer the case at the higher firing temperatures of current generation designs.

Given the importance of coatings, it must be recognized that even the best coatings available will have a finite life and the condition of the coating will play a major role in determining bucket replacement life. Refurbishment through stripping and recoating is an option for extending bucket life, but if recoating is selected, it should be done before the coating is breached to expose base metal. Normally, for turbines in the MS7001EA class, this means that recoating will be required at the hot gas path inspection. If recoating is not performed at the hot gas path inspection, the runout life of the buckets would generally extend to the major inspection, at which point the buckets would be replaced. For F class gas turbines recoating of the first stage buckets is recommended at each hot gas path inspection.

Visual and borescope examination of the hot gas path parts during the combustion inspections as well as nozzle-deflection measurements will allow the operator to monitor distress patterns and progression. This makes part-life predictions more accurate and allows adequate time to plan for replacement or refurbishment at the time of the hot-gas-path inspection. It is important to recognize that to avoid extending the hot gas path inspection, the necessary spare parts should be on site prior to taking the unit out of service.

Major Inspection

The purpose of the major inspection is to examine all of the internal rotating and stationary components from the inlet of the machine through the exhaust. A major inspection should be scheduled in accordance with the recommendations in the owner's Operations and Maintenance Manual or as modified by the results of previous borescope and hot gas path inspection. The work scope shown in *Figure 39* involves inspection of all of the major flange-to-flange components of the gas turbine, which are subject to deterioration during normal turbine operation. This inspection includes previous elements of the combustion and hot gas path inspections, in addition to laying open the complete flange-to-flange gas turbine to the horizontal joints, as shown in *Figure 40*.

Major Inspection

Hot Gas Path Inspection Scope – Plus:

Key Hardware:

- Compressor Blading
- Compressor and Turbine Rotor Dovetails
- Journals and Seal Surfaces
- Bearing, Seals
- Exhaust System

Inspect for:

- Foreign Object Damage
- Oxidation/Corrosion/Erosion
- Cracking
- Leaks
- Abnormal Wear
- Missing Hardware
- Clearance Limits

Potential Actions:

- Repair/Refurbishment/Replace
- Stator Shrouds
  Cracking/Oxidation/Erosion
- Buckets
  Coating Deterioration
  FOD/Rubs/Cracking
  Tip Shroud Deflection
  Creep Life Limit
- Nozzles
  Severe Deterioration
- IGV Bushings
  Wear
- Bearings/Seals
  Scoring/Wear
- Compressor Blades
  Corrosion/Erosion
  Rubs/FOD
- Rotor Inspection

Criteria

- Op. & Instr. Manual
- TIL's
- GE Field Engineer

Inspection Methods

- Visual
- LP
- Ultrasonics
- Borescope

Figure 39. Gas turbine major inspection – key elements

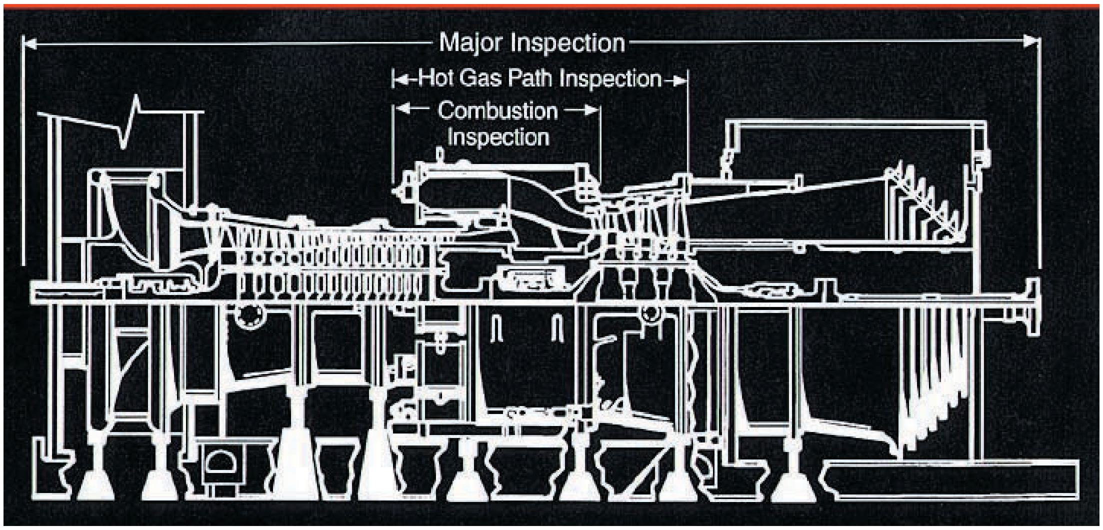


Figure 40. Major inspection work scope

Removal of all of the upper casings allows access to the compressor rotor and stationary compressor blading, as well as to the bearing assemblies. Prior to removing casings, shells and frames, the unit must be properly supported. Proper centerline support using mechanical jacks and jacking sequence procedures are necessary to assure proper alignment of rotor to stator, obtain accurate half shell clearances and to prevent twisting of the casings while on the half shell.

Typical major inspection requirements for all machines are:

- All radial and axial clearances are checked against their original values (opening and closing).
- Casings, shells and frames/diffusers are inspected for cracks and erosion.
- Compressor inlet and compressor flow-path are inspected for fouling, erosion, corrosion and

leakage. The IGVs are inspected, looking for corrosion, bushing wear and vane cracking.

- Rotor and stator compressor blades are checked for tip clearance, rubs, impact damage, corrosion pitting, bowing and cracking.
- Turbine stationary shrouds are checked for clearance, erosion, rubbing, cracking, and build-up.
- Seals and hook fits of turbine nozzles and diaphragms are inspected for rubs, erosion, fretting or thermal deterioration.
- Turbine buckets are removed and a non-destructive check of buckets and wheel dovetails is performed (first stage bucket protective coating should be evaluated for remaining coating life). Buckets that were not recoated at the hot gas path inspection should be replaced. Wheel dovetail fillets, pressure faces, edges, and intersecting features must be closely examined for conditions of wear, galling, cracking or fretting.
- Rotor inspections recommended in the maintenance and inspection manual or by Technical Information Letters should be performed.
- Bearing liners and seals are inspected for clearance and wear.
- Inlet systems are inspected for corrosion, cracked silencers and loose parts.
- Exhaust systems are inspected for cracks, broken silencer panels or insulation panels.
- Check alignment – gas turbine to generator/gas turbine to accessory gear.

Comprehensive inspection and maintenance guidelines have been developed by GE and are provided in the Operations and Maintenance Manual to assist users in performing each of the inspections previously described.

PARTS PLANNING

Lack of adequate on-site spares can have a major effect on plant availability; therefore, prior to a scheduled disassembly type of inspection, adequate spares should be on site. A planned outage such as a combustion inspection, which should only take two to five days, could take weeks. GE will provide recommendations regarding the types and quantities of spare parts needed; however, it is up to the owner to purchase these spare parts on a planned basis allowing adequate lead times.

Early identification of spare parts requirements ensures their availability at the time the planned inspections are performed. There are two documents which support the ordering of gas turbine parts by catalog number. The first is the Renewal Parts Catalog – Illustrations and Text. This document contains generic illustrations which are used for identifying parts. The second document, the Renewal Parts Catalog Ordering Data Manual, contains unit site-specific catalog ordering data.

Additional benefits available from the renewal parts catalog data system are the capability to prepare recommended spare parts lists for the combustion, hot-gas-path and major inspections as well as capital and operational spares.

Furthermore, interchangeability lists may be prepared for multiple units. The information contained in the Catalog Ordering Data Manual can be provided as a computer printout, on microfiche or on a computer disc. As the size of the database grows, and as generic illustrations are added, the usefulness of this tool will be continuously enhanced.

Typical expectations for estimated repair cycles for some of the major components are shown in *Appendix D*. These tables assume that operation of the unit has been in accordance with all of the manufacturer's specifications and instructions. Maintenance inspections and repairs are also assumed to be done in accordance with the manufacturer's specifications and instructions. The actual repair and replacement cycles for any particular gas turbine should be based on the user's operating procedures, experience, maintenance practices and repair practices. The maintenance factors previously described can have a major impact on both the component repair interval and service life. For this reason, the intervals given in *Appendix D* should only be used as guidelines and not certainties for long range parts planning. Owners may want to include contingencies in their parts planning.

The expected repair and replacement cycle values reflect current production hardware.

To achieve these lives, current production parts with design improvements and newer coatings are required. With earlier production hardware, some of these lives may not be achieved. Operating factors and experience gained during the course of recommended inspection and maintenance procedures will be a more accurate predictor of the actual intervals.

Appendix D shows expected repair and replacement intervals based on the recommended inspection intervals shown in *Figure 42*. The application of inspection (or repair) intervals other than those shown in *Figure 42* can result in different replacement intervals (as a function of the number of repair intervals) than those shown in *Appendix D*. See your GE representative for details on a specific system.

It should be recognized that, in some cases, the service life of a component is reached when it is no longer economical to repair any deterioration as opposed to replacing at a fixed interval. This is illustrated in *Figure 41* for a first stage nozzle, where repairs continue until either the nozzle cannot be restored to minimum acceptance standards or the repair cost exceeds or approaches the replacement cost. In other cases, such as first-stage buckets, repair options are limited by factors such as irreversible material damage. In both cases, users should follow GE recommendations regarding replacement or repair of these components.

While the parts lives shown in *Appendix D* are guidelines, the life consumption of individual parts within a parts set can have variations. The repair versus replacement economics shown in *Figure 41* may lead to a certain percentage of "fallout," or scrap, of parts being repaired. Those parts that fallout during the repair process will need to be replaced by new parts. The amount of fallout of parts depends on the unit operating environment history, the specific part design, and the current state-of-the-art for repair technology.

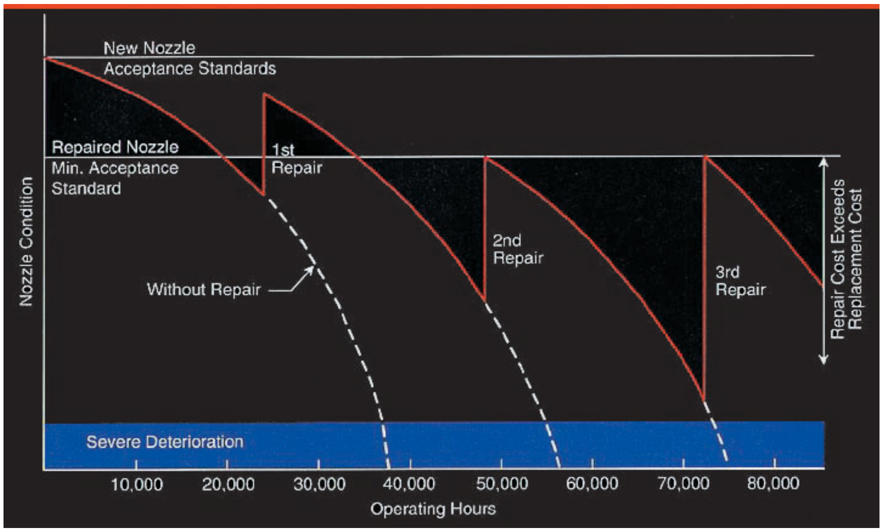


Figure 41. First-stage nozzle wear-preventive maintenance gas fired – continuous dry – base load

Type of Inspection	Combustion System	Factored Hours / Factored Starts										
		MS3002K	MS5001PA/ MS5002C,D	MS6B	MS7E/EA	MS9E	MS6FA	MS7F/FA/FA+	MS7FA+e	MS9F/FA/FA+	MS9FA+e	MS7FB
Combustion	Non-DLN	24,000/400	12,000/800(1)(3)	12,000/1,200(2)(3)	8,000/900(3)	8,000/900(3)	–	–	–	–	–	–
	DLN	–	8,000/400	12,000/450	12,000/450	12,000/450	8,000/450	8,000/450	12,000/450	8,000/450	8,000/450	8,000/450
Hot Gas Path		24,000/1,200	Eliminated/1,200	24,000/1,200	24,000/1,200	24,000/900	24,000/900	24,000/900	24,000/900	24,000/900	24,000/900	24,000/900
Major		48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400	48,000/2,400

Factors That Can Reduce Maintenance Intervals

- Fuel
- Load Setting
- Steam/water injection
- Peak Load TF Operation
- Trips
- Start Cycle
- Hardware Design

(1) Units with Lean Head End liners have a 400 starts combustion inspection interval.
(2) Machines with 6581 and 6BeV combustion hardware have a 12,000/600 combustion inspection interval.
(3) Multiple Non-DLN configurations exist (Standard, MNQC, IGCC). The most limiting case is shown, however different quoting limits may exist on a machine and hardware basis. Contact a GE Energy representative for further information.

NOTE: Factored Hours/Starts intervals include an allowance for nominal trip maintenance factor effects.
Hours/Starts intervals for Major Inspection are quoted in Actual Hours and Actual Starts.

Figure 42. Base line recommended inspection intervals: base load – gas fuel – dry

INSPECTION INTERVALS

Figure 42 lists the recommended combustion, hot-gas-path and major inspection intervals for current production GE turbines operating under ideal conditions of gas fuel, base load, and no water or steam injection. Considering the maintenance factors discussed previously, an adjustment from these maximum intervals may be necessary, based on the specific operating conditions of a given application. Initially, this determination is based on the expected operation of a turbine installation, but this should be reviewed and adjusted as actual operating and maintenance data are accumulated. While reductions in the maximum intervals will result from the factors described previously, increases in the maximum interval can also be considered where operating experience has been favorable. The condition of the hot-gas-path parts provides a good basis for customizing a program of inspection and maintenance; however, the condition of the compressor and bearing assemblies is the key driver in planning a Major Inspection.

GE can assist operators in determining the appropriate maintenance intervals for their particular application. Equations have been developed that account for the factors described earlier and can be used to determine application specific hot gas path and major inspection intervals.

Hot Gas Path Inspection Interval

The hours-based hot gas path criterion is determined from the equation given in *Figure 43*. With this equation, a maintenance factor is determined that is the ratio of factored operating hours and actual operating hours. The factored hours consider the specifics of the duty cycle relating to fuel type, load setting and steam or water injection. Maintenance factors greater than one reduce the hot gas path inspection interval from the 24,000 hour ideal case for continuous base load, gas fuel and no steam or water injection. To determine the application specific maintenance interval, the maintenance factor is divided into 24,000, as shown in *Figure 43*.

The starts-based hot-gas-path criterion is determined from the equation given in *Figure 44*. As with the hours-based criteria, an application specific starts-based hot gas path inspection interval is calculated from a maintenance factor that is determined from the number of trips typically being experienced, the load level and loading rate.

As previously described, the hours and starts operating spectrum for the application is evaluated

Hours-Based HGP Inspection

$$\text{Maintenance Interval (Hours)} = \frac{24000}{\text{Maintenance Factor}}$$

Where:

$$\text{Maintenance Factor} = \frac{\text{Factored Hours}}{\text{Actual Hours}}$$

Factored Hours = $(K + M \times I) \times (G + 1.5D + A_f H + 6P)$
Actual Hours = $(G + D + H + P)$
G = Annual Base Load Operating hours on Gas Fuel
D = Annual Base Load Operating hours on Distillate Fuel
H = Annual Operating Hours on Heavy Fuel
A_f = Heavy Fuel Severity Factor (Residual A_f = 3 to 4, Crude A_f = 2 to 3)
P = Annual Peak Load Operating Hours
I = Percent Water/Steam Injection Referenced to Inlet Air Flow
M&K = Water/Steam Injection Constants

M	K	Control	Steam Injection	N2/N3 Material
0	1	Dry	<2.2%	GTD-222/FSX-414
0	1	Dry	>2.2%	GTD-222
.18	.6	Dry	>2.2%	FSX-414
.18	1	Wet	>0%	GTD-222
.55	1	Wet	>0%	FSX-414

Figure 43. Hot gas path maintenance interval: hours-based criterion

against the recommended hot gas path intervals for starts and for hours. The limiting criterion (hours or starts) determines the maintenance interval. An example of the use of these equations for the hot gas path is contained in *Appendix A*.

Rotor Inspection Interval

Like HGP components, the unit rotor has a maintenance interval involving removal, disassembly and thorough inspection. This interval indicates the serviceable life of the rotor and is generally considered to be the teardown inspection and repair/replacement interval for the rotor. Customers should contact GE when their rotor has reached the end of its serviceable life for technical advisement.

The starts-based rotor maintenance interval is determined from the equation given in *Figure 45*. Adjustments to the rotor maintenance interval are determined from rotor-based operating factors as were described previously. In the calculation for the starts-based rotor maintenance interval, equivalent starts are determined for cold, warm, and hot starts

Starts-Based HGP Inspection

$$\text{Maintenance Interval (Starts)} = \frac{S}{\text{Maintenance Factor}}$$

Where:

$$\text{Maintenance Factor} = \frac{\text{Factored Starts}}{\text{Actual Starts}}$$

Factored Starts = $0.5N_A + N_B + 1.3N_P + 20E + 2F + \sum_{i=1}^{\eta} (a_{T_i} - 1)\, T_i$

Actual Starts = $(N_A + N_B + N_P)$

S = Maximum Starts-Based Maintenance Interval (Model Size Dependent)
N_A = Annual Number of Part Load Start/Stop Cycles (<60% Load)
N_B = Annual Number of Base Load Start/Stop Cycles
N_P = Annual Number of Peak Load Start/Stop Cycles (>100% Load)
E = Annual Number of Emergency Starts
F = Annual Number of Fast Load Starts
T = Annual Number of Trips
a_T = Trip Severity Factor = f(Load) (See Figure 21)
η = Number of Trip Categories (i.e.Full Load, Part Load, etc.)

Model Series	S	Model Series	S
MS6B/MS7EA	1,200	MS9E	900
MS6FA	900	7/9 F Class	900

Figure 44. Hot gas path maintenance interval: starts-based criterion

Starts-Based Rotor Inspection

$$\text{Rotor Maintenance Interval} = \frac{5000^{(1)}}{\text{Maintenance Factor}}$$

(Not to exceed 5000 starts)
MF>=1

$$\text{Maintenance Factor} = \frac{F_h \cdot N_h + F_{w1} \cdot N_{w1} + F_{w2} \cdot N_{w2} + F_c \cdot N_c + F_t \cdot N_t}{N_h + N_{w1} + N_{w2} + N_c}$$

Number of Starts

N_h = Number of hot starts
N_{w1} = Number of Warm1 starts
N_{w2} = Number of Warm2 starts
N_c = Number of cold starts
N_t = Number of trips

Start Factors

F_h = Hot start factor (Down 1-4 hr)*
F_{w1} = Warm1 start factor (Down 4-20 hr)
F_{w2} = Warm2 start factor (Down 20-40 hr)
F_c = Cold start factor (Down >40 hr)
F_t = Trip from load factor

(1) F class

Note: Start factors for 7/9 FA+e machines are tabulated in Figure 23.
For other F Class machines, refer to applicable TILs.

Figure 45. Rotor maintenance interval: starts-based criterion

over a defined time period by multiplying the appropriate cold, warm and hot start operating factors by the number of cold, warm and hot starts respectively. In this calculation, the classification of start is key. Additionally, equivalent starts for trips from load are added. The total equivalent starts are divided by the actual number of starts to yield the maintenance factor. The rotor starts-based maintenance interval for a specific application is determined by dividing the baseline rotor maintenance interval of 5000 starts by the calculated maintenance factor. As indicated in *Figure 45*, the baseline rotor maintenance interval is also the maximum interval, since calculated maintenance factors less than one are not considered.

Figure 46 describes the procedure to determine the hours-based maintenance criterion. Peak load operation is the primary maintenance factor for the F class rotors and will act to increase the hours-based maintenance factor and to reduce the rotor maintenance interval.

When the rotor reaches the limiting inspection interval determined from the equations described in *Figures 45 and 46*, a disassembly of the rotor is required so that a complete inspection of the rotor components in both the compressor and turbine can be performed. It should be expected that some rotor components will require replacement at this inspection point, and depending on the extent of refurbishment and part replacement, subsequent inspections may be required at a reduced interval.

As with major inspections, the rotor repair interval should include thorough dovetail inspections for wear and cracking. The baseline rotor life is predicated upon sound inspection results at the majors.

The baseline intervals of 144,000 hours and 5000

Hours-Based Rotor Inspection

$$\text{Rotor Maintenance Interval} = \frac{144000^{(1)}}{\text{Maintenance Factor}}$$

$$\text{Maintenance Factor} = \frac{H + 2^{*}P^{(2)}}{H + P}$$

Where:

H ~ Base load hours
P ~ Peak load hours

(1) F class
(2) For E-class, MF = (H + 2*P + 2*TG) / (H + P), where TG is hours on turning gear.

Note: To diminish potential turning gear impact, Major Inspections must include a thorough visual examination of the turbine dovetails for signs of wearing, galling, fretting, or cracking.

Figure 46. Rotor maintenance interval: hours-based criterion

starts in *Figures 45 and 46* pertain to F class rotors. For rotors other than F class, rotor maintenance should be performed at intervals recommended by GE through issued Technical Information Letters (TILs). Where no recommendations have been made, rotor inspection should be performed at 5,000 factored starts or 200,000 factored hours.

Combustion Inspection Interval

Equations have been developed that account for the earlier mentioned factors affecting combustion maintenance intervals. These equations represent a generic set of maintenance factors that provide general guidance on maintenance planning. As such, these equations do not represent the specific capability of any given combustion system. They do provide, however, a generalization of combustion system experience. See your GE Energy representative for maintenance factors and limitations of specific combustion systems. For combustion parts, the base line operating conditions that result in a maintenance factor of unity are normal fired start-up and shut-down (no trip) to base load on natural gas fuel without steam or water injection. Application of the Extendor™ Combustion System Wear Kit has the potential to significantly increase maintenance intervals.

An hours-based combustion maintenance factor can be determined from the equations given in *Figure 47* as the ratio of factored-hours to actual operating hours. Factored-hours considers the effects of fuel type, load setting and steam or water injection. Maintenance factors greater than one reduce recommended combustion inspection intervals from those shown in *Figure 42* representing baseline operating conditions. To obtain a recommended inspection interval for a specific application, the maintenance factor is divided into the recommended base line inspection interval.

A starts-based combustion maintenance factor can be determined from the equations given in *Figure 48* and considers the effect of fuel type, load setting, emergency starts, fast loading rates, trips and steam or water injection. An application specific recommended inspection interval can be determined from the baseline inspection interval in *Figure 42* and the maintenance factor from *Figure 48*.

Appendix B shows six example maintenance factor calculations using the above hours and starts maintenance factors equations.

Maintenance Factor = (Factored Hours)/(Actual Hours)
Factored Hours = $\sum (K_i \times Af_i \times Ap_i \times t_i)$, i = 1 to n Operating Modes
Actual Hours = $\sum (t_i)$, i = 1 to n Operating Modes
Where:
  i = Discrete Operating mode (or Operating Practice of Time Interval)
  t_i = Operating hours at Load in a Given Operating mode
  Ap_i = Load Severity factor
    Ap = 1.0 up to Base Load
    Ap = exp(0.018 x Peak Firing Temp Adder in deg F) for Peak Load
  Af_i = Fuel Severity Factor (dry)
    Af = 1.0 for Gas Fuel (1)
    Af = 1.5 for Distillate Fuel, Non-DLN (2.5 for DLN)
    Af = 2.5 for Crude (Non-DLN)
    Af = 3.5 for Residual (Non-DLN)
  K_i = Water/Steam Injection Severity Factor
    (% Steam Referenced to Inlet Air Flow, w/f = Water to Fuel Ratio)
    K = Max(1.0, exp(0.34(%Steam – 2.00%))) for Steam, Dry Control Curve
    K = Max(1.0, exp(0.34(%Steam – 1.00%))) for Steam, Wet Control Curve
    K = Max(1.0, exp(1.80(w/f – 0.80))) for Water, Dry Control Curve
    K = Max(1.0, exp(1.80(w/f – 0.40))) for Water, Wet Control Curve

(1) Af = 10 for DLN 1 extended lean-lean and DLN 2.0 lean-lean operating modes.

Figure 47. Combustion inspection hours-based maintenance factors

Maintenance Factor = (Factored starts)/(Actual Starts)
Factored Starts = $\sum (K_i \times Af_i \times At_i \times Ap_i \times As_i \times N_i)$, i = 1 to n Start/Stop Cycles
Actual Starts = $\sum (N_i)$, i = 1 to n Start/Stop Cycles
Where:

- i = Discrete Start/Stop Cycle (or Operating Practice)
- N_i = Start/Stop Cycles in a Given Operating Mode
- As_i = Start Type Severity Factor
    - As = 1.0 for Normal Start
    - As = 1.2 for Start with Fast Load
    - As = 3.0 for Emergency Start
- Ap_i = Load Severity Factor
    - Ap = 1.0 up to Base Load
    - Ap = exp(0.009 x Peak Firing Temp Adder in deg F) for Peak Load
- At_i = Trip Severity Factor
    - At = 0.5 + exp(0.0125*%Load) for Trip
- Af_i = Fuel Severity Factor (Dry, at Load)
    - Af = 1.0 for Gas Fuel
    - Af = 1.25 for Non-DLN (or 1.5 for DLN) for Distillate Fuel
    - Af = 2.0 for Crude (Non-DLN)
    - Af = 3.0 for Residual (Non-DLN)
- K_i = Water/Steam Injection Severity Factor
    - (%Steam Referenced to Inlet Air Flow, w/f = Water to Fuel Ratio)
    - K = Max(1.0, exp(0.34(%Steam – 1.00%))) for Steam, Dry Control Curve
    - K = Max(1.0, exp(0.34(%Steam – 0.50%))) for Steam, Wet Control Curve
    - K = Max(1.0, exp(1.80(w/f – 0.40))) for Water, Dry Control Curve
    - K = Max(1.0, exp(1.80(w/f – 0.20))) for Water, Wet Control Curve

Figure 48. Combustion inspection starts-based maintenance factors

MANPOWER PLANNING

It is essential that advanced manpower planning be conducted prior to an outage. It should be understood that a wide range of experience, productivity and working conditions exist around the world. However, based upon maintenance inspection man-hour assumptions, such as the use of an average crew of workers in the United States with trade skill (but not necessarily direct gas turbine experience), with all needed tools and replacement parts (no repair time) available, an estimate can be made. These estimated craft labor man-hours should include controls and accessories and the generator. In addition to the craft labor, additional resources are needed for technical direction of the craft labor force, specialized tooling, engineering reports, and site mobilization/de-mobilization.

Inspection frequencies and the amount of downtime varies within the gas turbine fleet due to different duty cycles and the economic need for a unit to be in a state of operational readiness. It can be demonstrated that an 8000-hour interval for a combustion inspection with minimum downtime can be achievable based on the above factors. Contact your local GE Energy representative for the specific man-hours and recommended crew size for your specific unit.

Depending upon the extent of work to be done during each maintenance task, a cooldown period of 4 to 24 hours may be required before service may be performed. This time can be utilized productively for job move-in, correct tagging and locking equipment out-of-service and general work preparations. At the conclusion of the maintenance work and systems check out, a turning gear time of two to eight hours is normally allocated prior to starting the unit. This time can be used for job clean-up and arranging for any repairs required on removed parts.

Local GE field service representatives are available to help plan your maintenance work to reduce downtime and labor costs. This planned approach will outline the renewal parts that may be needed and the projected work scope, showing which tasks can be accomplished in parallel and which tasks must be sequential. Planning techniques can be used to reduce maintenance cost by optimizing lifting equipment schedules and manpower requirements. Precise estimates of the outage duration, resource requirements, critical-path scheduling, recommended replacement parts, and costs associated with the inspection of a specific installation may be obtained from the local GE field services office.

CONCLUSION

GE heavy-duty gas turbines are designed to have an inherently high availability. To achieve maximum gas turbine availability, an owner must understand not only the equipment, but the factors affecting it. This includes the training of operating and maintenance personnel, following the manufacturer's recommendations, regular periodic inspections and the stocking of spare parts for immediate replacement. The recording of operating data, and analysis of these data, are essential to preventative and planned maintenance. A key factor in achieving this goal is a commitment by the owner to provide effective outage management and full utilization of published instructions and the available service support facilities.

It should be recognized that, while the manufacturer provides general maintenance recommendations, it is the equipment user who has the major impact upon the proper maintenance and operation of equipment. Inspection intervals for optimum turbine service are not fixed for every installation, but rather are developed through an interactive process by each user, based on past experience and trends indicated by key turbine factors. In addition, through application of a Contractual Service Agreement to a particular turbine, GE can work with a user to establish a maintenance program that may differ from general recommendations but will be consistent with contractual responsibilities.

The level and quality of a rigorous maintenance program have a direct impact on equipment reliability and availability. Therefore, a rigorous maintenance program which optimizes both maintenance cost and availability is vital to the user. A rigorous maintenance program will minimize overall costs, keep outage downtimes to a minimum, improve starting and running reliability and provide increased availability and revenue earning ability for GE gas turbine users.

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ACKNOWLEDGMENTS

Tim Lloyd and Michael Hughes dedicated many hours to the detailed development of this document and their hard work is sincerely appreciated. Keith Belsom, Durell Benjamin, Mark Cournoyer, Richard Elliott, Tom Farrell, Jeff Hamilton, Steve Hartman, Jack Hess, Bob Hoeft, Patrick Mathieu, Stephen Norcross, Eric Smith, and Bert Stuck are also acknowledged for significant contributions.

APPENDIX

A.1) Example 1 – Hot Gas Path Maintenance Interval Calculation

An MS7001EA user has accumulated operating data since the last hot gas path inspection and would like to estimate when the next one should be scheduled. The user is aware from GE publications that the normal HGP interval is 24,000 hours if operating on natural gas, with no water or steam injection, and at base load. It is also understood that the nominal starts interval is 1200, based on normal startups, no trips, no emergency starts. The actual operation of the unit since the last hot gas path inspection is much different from the GE "baseline case."

Annual hours on natural gas, base load
= G = 3200 hr/yr

Annual hours on light distillate
= D = 350 hr/yr

Annual hours on peak load
= P = 120 hr/yr

Steam injection rate
= I = 2.4%

Also, since the last hot gas path inspection,

140 Normal start-stop cycles:

40 Part load

100 Base load

0 Peak load

In addition,

E = 2 Emergency Starts w / ramp to base load

F = 5 Fast loads ending in a normal shut down from base load

T = 20 Starts with trips from base load (a_{Ti} = 8)

For this particular unit, the second and third-stage nozzles are FSX-414 material. The unit operates on "dry control curve."

From *Figure 43*, at a steam injection rate of 2.4%, the value of "M" is .18, and "K" is .6.

From the hours-based criteria, the maintenance factor is determined from Figure 43.

$$MF = \frac{[K + M(I)] \times [G + 1.5(D) + Af(H) + 6(P)]}{(G + D + H + P)}$$

$$MF = \frac{[.6 + .18(2.4)] \times [3200 + 1.5(350) + 0 + 6(120)]}{(3200 + 350 + 0 + 120)}$$

$$MF = 1.25$$

The hours-based adjusted inspection interval is therefore,

$H = 24{,}000/1.25$

$H = 19{,}200$ hours [Note, since total annual operating hours is 3670, the estimated time to reach 19,200 hours is 5.24 years (19,200/3670).]

From the starts-based criteria, the maintenance factor is determined from *Figure 44*.

The total number of part load starts is
$N_A = 40/yr$

The total number of base load starts is
$N_B = 100 + 2 + 5 + 20 = 127/yr$

The total number of peak load starts is
$N_P = 0/yr$

$$MF = \frac{[0.5 (N_A)+(N_B)+1.3(N_P)+20(E)+2(F) + \sum_{i=1}^{n}(a_{TI} - 1) T_i}{N_A + N_B + N_P}$$

$$MF = \frac{0.5(40)+(127)+1.3(0)+20(2)+2(5)+(8–1)20}{40+127+0}$$

$$MF = 2$$

The adjusted inspection interval based on starts is

$S = 1200/2.0$

$S = 600$ starts [Note, since the total annual number of starts is 167, the estimated time to reach 600 starts is 600/167 = 3.6 years.]

In this case, the starts-based maintenance factor is greater than the hours maintenance factor and therefore the inspection interval is set by starts. The hot gas path inspection interval is 600 starts (or 3.6 years).

A.2) Example 2 – Hot Gas Path Factored Starts Calculation

An MS7001EA user has accumulated operating data for the past year of operation. This data shows number of trips from part, base, and peak load, as well as emergency starting and fast loading. The user would like to calculate the total number of factored starts in order to plan the next HGP outage. *Figure 44* is used to calculate the total number of factored starts as shown below.

Operational history:

- 150 Start-stop cycles per year:
  - 40 Part load
  - 60 Base load
  - 50 Peak load
- 50 ending in trips:
  - 10 from 105% load
  - 5 from 50% load (part load)
  - 35 from 65% load (base load)

In addition,

- 3 Emergency Starts w / ramp to base load:
  - 2 ended in a trip from full load
  - 1 ended in a normal shutdown
- 4 Fast loads:
  - 1 tripped during loading at 50% load
  - 3 achieved base load and ended in a normal shutdown

Total Starts

Part Load, $N_A = 40 + 1 = 41$

Base Load, $N_B = 60 + 3 + 3 = 66$

Peak Load, $N_P = 50$

Total Trips

1. 50% load (aT_1=6.5), $T_1 = 5 + 1 = 6$
2. Full load (aT_2=8), $T_2 = 35 + 2 = 37$
3. Peak load (aT_3=10), $T_3 = 10$

Additional Cycles

Emergency starting, $E = 3$

Fast loading, $F = 4$

From the starts-based criteria, the total number of factored starts is determined from *Figure 44.*

$$FS = 0.5(NA)+(NB)+1.3(NP)+20(E)+2(F)+\sum_{i=1}^{n}(a_{Ti}-1)T_i$$

$$FS = 0.5(41)+(66)+1.3(50)+20(3)+2(4)+[(6.5–1)6+(8–1)37+(10–1)10]=601.50$$

$$AS = 41 + 66 + 50 = 157$$

$$MF = \frac{601.5}{157} = 3.8$$

B) Examples – Combustion Maintenance Interval Calculations (reference Figures 47 and 48)

7EA DLN 1 Peaking Duty with Power Augmentation

+50F Tfire Increase	Gas Fuel
3.5% Steam Augmentation	6 Hours/Start
Start with Fast Load	Wet Control Curve
Normal Shut Down (No Trip)	

Factored Hours = Ki * Afi * Api * ti = 34.5 Hours
Hours Maintenance Factor = (34.5/6) **5.8**
Where Ki = 2.34 Max(1.0, exp(0.34(3.50-1.00))) Wet
Afi = 1.00 Gas Fuel
Api = 2.46 exp(0.018(50)) Peaking
ti = 6.0 Hours/Start

Factored Starts = Ki * Afi * Ati * Api * Asi * Ni = 5.2 Starts
Starts Maintenance Factor = (5.2/1) **5.2**
Where Ki = 2.77 Max(1.0, exp(0.34(3.50-0.50))) Wet
Afi = 1.00 Gas Fuel
Ati = 1.00 No Trip at Load
Api = 1.57 exp(0.009(50)) Peaking
Asi = 1.20 Start with Fast Load
Ni = 1.0 Considering Each Start

7EA Standard Combustor Baseload on Crude Oil

No Tfire Increase	Crude Oil Fuel
1.0 Water/Fuel Ratio	220 Hours/Start
Normal Start and Load	Dry Control Curve
Normal Shut Down (No Trip)	

Factored Hours = Ki * Afi * Api * ti = 788.3 Hours
Hours Maintenance Factor = (788.3/220) **3.6**
Where Ki = 1.43 Max(1.0, exp(1.80(1.00-0.80))) Dry
Afi = 2.50 Crude Oil, Std (Non-DLN)
Api = 1.00 Baseload
ti = 220.0 Hours/Start

Factored Starts = Ki * Afi * Ati * Api * Asi * Ni = 5.9 Starts
Starts Maintenance Factor = (5.9/1) **5.9**
Where Ki = 2.94 Max(1.0, exp(1.80(1.00-0.40))) Dry
Afi = 2.00 Crude Oil, Std (Non-DLN)
Ati = 1.00 No Trip at Load
Api = 1.00 Baseload
Asi = 1.00 Normal Start
Ni = 1.0 Considering Each Start

7FA+e DLN 2.6 Baseload on Distillate

No Tfire Increase	Distillate Fuel
1.1 Water/Fuel Ratio	220 Hours/Start
Normal Start	Dry Control Curve
Normal Shut Down (No Trip)	

Factored Hours = Ki * Afi * Api * ti = 943.8 Hours
Hours Maintenance Factor = (943.8/220) **4.3**
Where Ki = 1.72 Max(1.0, exp(1.80(1.10-0.80))) Dry
Afi = 2.50 Distillate Fuel, DLN
Api = 1.00 Baseload
ti = 220.0 Hours/Start

Factored Starts = Ki * Afi * Ati * Api * Asi * Ni = 5.3 Starts
Starts Maintenance Factor = (5.3/1) **5.3**
Where Ki = 3.53 Max(1.0, exp(1.80(1.10-0.40))) Dry
Afi = 1.50 Distillate Fuel, DLN
Ati = 1.00 No Trip at Load
Api = 1.00 Baseload
Asi = 1.00 Normal Start
Ni = 1.0 Considering Each Start

7FA+e DLN 2.6 Baseload on Gas with Trip @ Load

No Tfire Increase	Gas Fuel
No Steam/Water Injection	168 Hours/Start
Normal Start and Load	Dry Control Curve
Trip @ 60% Load	

Factored Hours = Ki * Afi * Api * ti = 168.0 Hours
Hours Maintenance Factor = (168.0/168) **1.0**
Where Ki = 1.00 No Injection
Afi = 1.00 Gas Fuel
Api = 1.00 Baseload
ti = 168.0 Hours/Start

Factored Starts = Ki * Afi * Ati * Api * Asi * Ni = 2.6 Starts
Starts Maintenance Factor = (2.6/1) **2.6**
Where Ki = 1.00 No Injection
Afi = 1.00 Gas Fuel
Ati = 2.62 0.5+exp(0.0125*60) for Trip
Api = 1.00 Baseload
Asi = 1.00 Normal Start
Ni = 1.0 Considering Each Start

7EA DLN 1 Combustor Baseload on Distillate

No Tfire Increase	Distillate Fuel
0.9 Water/Fuel Ratio	500 Hours/Start
Normal Start	Dry Control Curve
Normal Shut Down (No Trip)	

Factored Hours = Ki * Afi * Api * ti = 1496.5 Hours
Hours Maintenance Factor = (1496.5/500) **3.0**
Where Ki = 1.20 Max(1.0, exp(1.80(0.90-0.80))) Dry
Afi = 2.50 Distillate Fuel, DLN 1
Api = 1.00 Partload
ti = 500.0 Hours/Start

Factored Starts = Ki * Afi * Ati * Api * Asi * Ni = 3.7 Starts
Starts Maintenance Factor = (3.7/1) **3.7**
Where Ki = 2.46 Max(1.0, exp(1.80(0.90-0.40))) Dry
Afi = 1.50 Distillate Fuel, DLN
Ati = 1.00 No Trip at Load
Api = 1.00 Part Load
Asi = 1.00 Normal Start
Ni = 1.0 Considering Each Start

7FA+e DLN 2.6 Peak Load on Gas with Emergency Starts

+35F Tfire Increase	Gas Fuel
3.5% Steam Augmentation	4 Hours/Start
Emergency Start	Dry Control Curve
Normal Shut Down (No Trip)	

Factored Hours = Ki * Afi * Api * ti = 12.5Hours
Hours Maintenance Factor = (12.5/4) **3.1**
Where Ki = 1.67 Max(1.0, exp(0.34(3.50-2.00)))
Afi = 1.00 Gas Fuel
Api = 1.88 exp(0.018(35)) Peaking
ti = 4.0 Hours/Start

Factored Starts = Ki * Afi * Ati * Api * Asi * Ni = 9.6 Starts
Starts Maintenance Factor = (9.6/1) **9.6**
Where Ki = 2.34 Max(1.0, exp(0.34(3.50-1.00))) Dry
Afi = 1.00 Gas Fuel
Ati = 1.00 No Trip at Load
Api = 1.37 exp(0.009(35)) Peaking
Asi = 3.00 Emergency Start
Ni = 1.0 Considering Each Start

Figure B-1. Combustion maintenance interval calculations

C) Definitions

Reliability: Probability of not being forced out of service when the unit is needed — includes forced outage hours (FOH) while in service, while on reserve shutdown and while attempting to start normalized by period hours (PH) — units are %.

Reliability = (1-FOH/PH) (100)

FOH = total forced outage hours

PH = period hours

Availability: Probability of being available, independent of whether the unit is needed – includes all unavailable hours (UH) – normalized by period hours (PH) – units are %:

Availability = (1-UH/PH) (100)

UH = total unavailable hours (forced outage, failure to start, scheduled maintenance hours, unscheduled mainte nance hours)

PH = period hours

Equivalent Reliability: Probability of a multi-shaft combined-cycle power plant not being totally forced out of service when the unit is required includes the effect of the gas and steam cycle MW output contribution to plant output – units are %.

Equivalent Reliability =

$$[1 - \left[\frac{GT\ FOH}{GT\ PH} + B\left(\frac{HRSG\ FOH}{B\ PH} + \frac{ST\ FOH}{ST\ PH}\right)\right] \text{ x } 100]$$

GT FOH = Gas Turbine Forced Outage Hours

GT PH = Gas Turbine Period Hours

HRSG FOH = HRSG Forced Outage Hours

B PH = HRSG Period Hours

ST FOH = Steam Turbine Forced Outage Hours

ST PH = Steam Turbine Period Hours

B = Steam Cycle MW Output Contribution (normally 0.30)

Equivalent Availability: Probability of a multi-shaft combined-cycle power plant being available for power generation — independent of whether the unit is needed — includes all unavailable hours — includes the effect of the gas and steam cycle MW output contribution to plant output; units are %.

Equivalent Availability =

$$[1 - \left[\frac{GT\ UH}{GT\ PH} + B\left(\frac{HRSG\ UH}{GT\ PH} + \frac{ST\ UH}{ST\ PH}\right)\right] \text{ x } 100]$$

GT UH = Gas Turbine Unavailable Hours

GT PH = Gas Turbine Period Hours

HRSG UH = HRSG Total Unavailable Hours

ST UH = Steam Turbine Unavailable Hours

ST PH = Steam Turbine Forced Outage Hours

B = Steam Cycle MW Output Contribution (normally 0.30)

MTBF–Mean Time Between Failure: Measure of probability of completing the current run. Failure events are restricted to forced outages (FO) while in service – units are service hours.

MTBF = SH/FO

SH = Service Hours

FO = Forced Outage Events from a Running (On-line) Condition

Service Factor: Measure of operational use, usually expressed on an annual basis – units are %.

SF = SH/PH x 100

SH = Service Hours on an annual basis

PH = Period Hours (8760 hours per year)

Operating Duty Definition:

Duty	**Service Factor**	**Fired Hours/Start**
Stand-by	< 1%	1 to 4
Peaking	1% – 17%	3 to 10
Cycling	17% – 50%	10 to 50
Continuous	> 90%	>> 50

D) Repair and Replacement Cycles

MS3002K Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	2 (CI)	4 (CI)
Transition Pieces	CI, HGPI	2 (CI)	2 (HGPI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	MI	2 (MI)	2 (MI)
Stage 1 Shrouds	MI	2 (MI)	2 (MI)
Stage 2 Shrouds	MI	2 (MI)	2 (MI)
Stage 1 Bucket	–	1 (MI)(1)	3 (HGPI)
Stage 2 Bucket	–	1 (MI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
MI = Major Inspection Interval
(1) GE approved repair at 24,000 hours may extend life to 72,000 hours.

Figure D-1. Estimated repair and replacement cycles

MS5001PA / MS5002C,D Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	4 (CI)	3 (CI) / 4 (CI)(1)
Transition Pieces	CI, HGPI	4 (CI)(2)	2 (HGPI)
Stage 1 Nozzles	HGPI, MI	2 (MI)	2 (HGPI)
Stage 2 Nozzles	HGPI, MI	2 (MI)	2 (HGPI) / 2 (MI)(3)
Stage 1 Shrouds	MI	2 (MI)	2 (MI)
Stage 2 Shrouds	–	2 (MI)	2 (MI)
Stage 1 Bucket	–	1 (MI)(4)	3 (HGPI)
Stage 2 Bucket	–	1 (MI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
MI = Major Inspection Interval
(1) 3 (CI) for non-DLN units, 4 (CI) for DLN units
(2) Repair interval is every 2 (CI)
(3) 2 (HGPI) for MS5001PA, 2 (MI) for MS5002C, D
(4) GE approved repair at 24,000 hours will extend life to 72,000 hours

Figure D-2. Estimated repair and replacement cycles

PG6541-61 (6B)

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)(1) / 3 (HGPI)(2)	3 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(3)	4 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	4 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.
HGPI = Hot Gas Path Inspection Interval
(1) 2 (HGPI) with no repairs at 24k hours.
(2) 3 (HGPI) with Strip, HIP Rejuvenation, and Re-coat at 24k hours.
(3) May require meeting tip shroud engagement criteria at prior HGP repair intervals. 3 (HGPI) for current design only. Consult your GE Energy representative for replace intervals by part number.

Figure D-3. Estimated repair and replacement cycles

PG6571-81 (6BU) / 6BeV Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	4 (CI)	4 (CI) / 5 (CI)(1)
Caps	CI	4 (CI)	5 (CI)
Transition Pieces	CI	4 (CI)	4 (CI) / 5 (CI)(1)
Fuel Nozzles	CI	2 (CI)	2 (CI) / 3 (CI)(2)
Crossfire Tubes	CI	2 (CI)	2 (CI) / 3 (CI)(2)
Flow Divider (Distillate)	CI	3 (CI)	3 (CI)
Fuel Pump (Distillate)	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 1 Bucket	HGPI	3 (HGPI)(3) / 2 (HGPI)(4)	3 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(5)	4 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	4 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.
CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) 4 (CI) for non-DLN / 5 (CI) for DLN
(2) 2 (CI) for non-DLN / 3 (CI) for DLN
(3) 3 (HGPI) for 6BU with strip & recoat at first HGPI
(4) 2 HGPI for 6BeV
(5) 3 (HGPI) for current design only. Consult your GE Energy representative for replace intervals by part number.

Figure D-4. Estimated repair and replacement cycles

PG7001(EA) / PG9001(E) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	3 (CI) / 5 (CI)(1)	5 (CI)
Caps	CI	3 (CI)	5 (CI)
Transition Pieces	CI	4 (CI) / 6 (CI)(2)	6 (CI)
Fuel Nozzles	CI	2 (CI) / 3 (CI)(3)	3 (CI)
Crossfire Tubes	CI	2 (CI) / 3 (CI)(3)	3 (CI)
Flow Divider (Distillate)	CI	3 (CI)	3 (CI)
Fuel Pump (Distillate)	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 1 Bucket	HGPI	3 (HGPI)(4)(5)	3 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(6)	4 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	4 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) 3 (CI) for DLN / 5 (CI) for non-DLN

(2) 4 (CI) for DLN / 6 (CI) for non-DLN

(3) 2 (CI) for DLN / 3 (CI) for non-DLN

(4) Strip and Recoat is required at first HGPI to achieve 3 HGPI replace interval for all E-Class.

(5) Uprated 7EA machines (2055 Tfire) require HIP rejuvenation at first HGPI to achieve 3 HGPI replace interval.

(6) 3 (HGPI) interval requires meeting tip shroud engagement criteria at prior HGP repair intervals. Consult your GE Energy representative for details.

Figure D-5. Estimated repair and replacement cycles

PG6101(FA) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	2 (CI)	2 (CI)
End Covers		6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)(1)
Stage 2 Bucket	HGPI	1 (HGPI)(3)	3 (HGPI)(2)
Stage 3 Bucket	HGPI	3 (HGPI)(2)	3 (HGPI)(2)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) GE approved repair operations may be needed to meet expected life. Consult your GE Energy representative for details.

(2) With welded hardface on shroud, recoating at 1st HGPI is required to achieve replacement life.

(3) Repair may be required on non-scalloped-from-birth parts. Redesigned bucket is capable of 3 (HGPI).

Figure D-6. Estimated repair and replacement cycles

PG7211(F) / PG9301(F) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	1 (CI) / 2 (CI)(1)	1 (CI) / 2 (CI)(1)
End Covers		6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(2)	3 (HGPI)(2)
Stage 3 Bucket	HGPI	3 (HGPI)(2)	3 (HGPI)(2)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) 2 (CI) for 7211 / 1 (CI) for 9301.

(2) With welded hardface on shroud, recoating at 1st HGPI is required to achieve replacement life.

Figure D-7. Estimated repair and replacement cycles

PG7221(FA) / PG9311(FA) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	1 (CI) / 2 (CI)(1)	1 (CI) / 2 (CI)(1)
End Covers		6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)(2)
Stage 2 Bucket	HGPI	2 (HGPI)	3 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)(3)	3 (HGPI)(3)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) 2 (CI) for 7221 / 1 (CI) for 9311.

(2) GE approved repair operations may be needed to meet expected life. Consult your GE Energy representative for details.

(3) With welded hardface on shroud, recoating at 1st HGPI may be required to achieve replacement life.

Figure D-8. Estimated repair and replacement cycles

PG7231(FA) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	2 (CI)	2 (CI)
End Covers		6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)(1)
Stage 2 Bucket	HGPI	1 (HGPI)(2)	3 (HGPI)(3)
Stage 3 Bucket	HGPI	3 (HGPI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.
CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) Periodic inspections are recommended within each HGPI. GE approved repair operations may be needed to meet 2 (HGPI) replacement. Consult your GE Energy representative for details on both.
(2) Interval can be increased to 2 (HGPI) by performing a repair operation. Consult your GE Energy representative for details.
(3) Recoating at 1st HGPI may be required to achieve 3 HGPI replacement life.

Figure D-9. Estimated repair and replacement cycles

PG7241(FA) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	2 (CI)	5 (CI)
Caps	CI	3 (CI)	5 (CI)
Transition Pieces	CI	3 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	2 (CI)	2 (CI)
End Covers		4 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	3 (HGPI)(2)	2 (HGPI)(4)
Stage 2 Bucket	HGPI	3 (HGPI)(1)	3 (HGPI)(1)
Stage 3 Bucket	HGPI	3 (HGPI)(3)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.
CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) 3 (HGPI) for current design. Consult your GE Energy representative for replacement intervals by part number.
(2) GE approved repair procedure required at first HGPI for designs without platform cooling.
(3) GE approved repair procedure at 2nd HGPI is required to meet 3 (HGPI) replacement life.
(4) 2 (HGPI) for current design with GE approved repair at first HGPI. 3 (HGPI) is possible for redesigned bucket with platform undercut and cooling modifications.

Figure D-10. Estimated repair and replacement cycles

PG9351(FA) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	1 (CI)	1 (CI)
End Covers		6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	2 (HGPI)(1)	2 (HGPI)(3)
Stage 2 Bucket	HGPI	1 (HGPI)	3 (HGPI)(2)
Stage 3 Bucket	HGPI	3 (HGPI)(4)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) 2 (HGPI) for current design with GE approved repair at first HGPI. 3 (HGPI) is possible for redesigned bucket with platform undercut and cooling modifications.

(2) Recoating at 1st HGPI may be required to achieve 3 HGPI replacement life.

(3) GE approved repair procedure at 1 (HGPI) is required to meet 2 (HGPI) replacement life.

(4) GE approved repair procedure is required at second HGPI to meet 3 (HGPI) replacement life.

Figure D-11. Estimated repair and replacement cycles

PG7251(FB) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	3 (CI)	3 (CI)
Caps	CI	3 (CI)	3 (CI)
Transition Pieces	CI	3 (CI)	3 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	3 (CI)	3 (CI)
End Covers		3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Exhaust Diffuser	HGPI		
Stage 1 Bucket	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

Figure D-12. Estimated repair and replacement cycles

E) Boroscope Inspection Ports

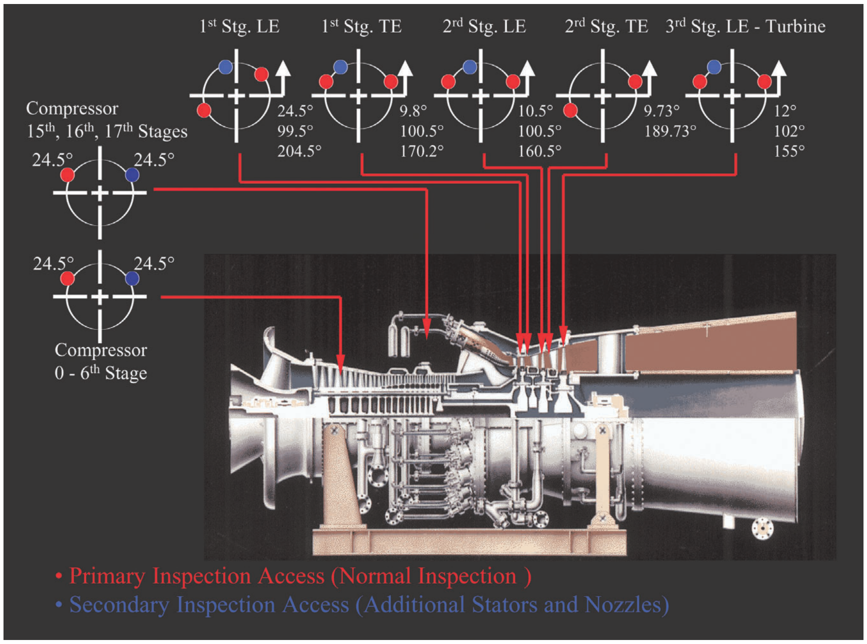

Figure E-1. Borescope inspection access locations for 6F machines

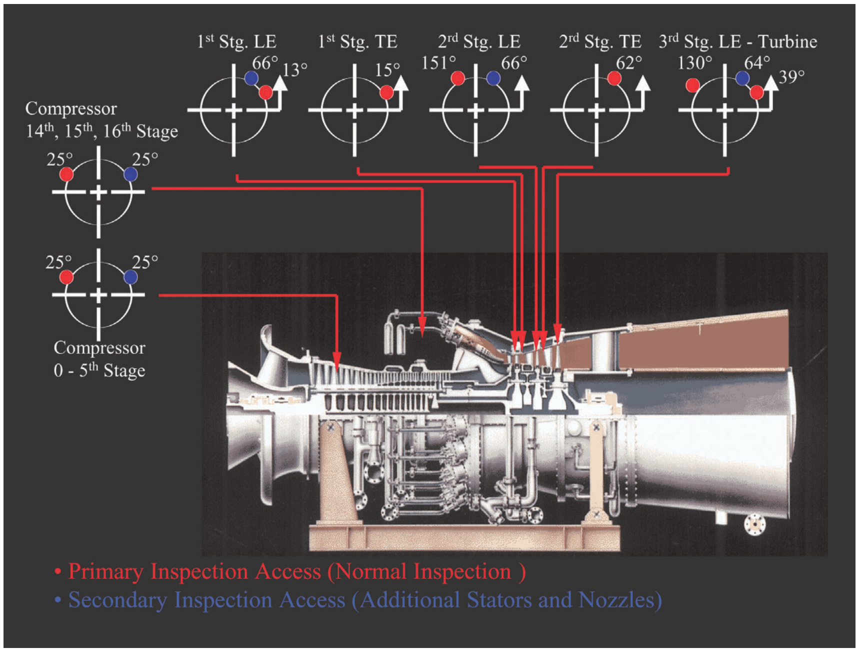

Figure E-2. Borescope inspection access locations for 7/9F machines

F) Turning Gear/Ratchet Running Guidelines

Scenario	Turning Gear (or Ratchet) Duration
Following Shutdown:	
Case A.1 – Normal. Restart anticipated for >48 hours	Until wheelspace temperatures <150F.(1) Rotor classified as unbowed. Minimum 24 hours.(2)
Case A.2 – Normal. Restart anticipated for <48 hours	Continuously until restart. Rotor unbowed.
Case B – Immediate rotor stop necessary. (Stop >20 minutes) Suspected rotating hardware damage or unit malfunction	None. Classified as bowed.
Before Startup:	
Case C – Hot rotor, <20 minutes after rotor stop	0–1 hour(3)
Case D – Warm rotor, >20 minutes & <6 hours after rotor stop	4 hours
Case E.1 – Cold rotor, unbowed, off TG <48 hours	4 hours
Case E.2 – Cold rotor, unbowed, off TG >48 hours	6 hours
Case F – Cold rotor, bowed	8 hours(4)
During Extended Outage:	
Case G – When idle	1 hour/day
Case H – Alternative	No TG; 1 hour/week at full speed (no load).(5)

(1) Time depends on frame size and ambient environment.
(2) Cooldown cycle may be accelerated using starting device for forced cooldown. Turning gear, however, is recommended method.
(3) 1 hour on turning gear is recommended following a trip, before restarting. For normal shutdowns, use discretion.
(4) Follow bowed rotor startup procedure. See Operation and Maintenance Manual.
(5) Avoids high cycling of lube oil pump during long outages.

Figure F-1. Turning Gear Guidelines

Revision History

9/89 Original

8/91 Rev A

9/93 Rev B

3/95 Rev C

- Nozzle Clearances section removed
- Steam/Water Injection section added
- Cyclic Effects section added

5/96 Rev D

- Estimated Repair and Replacement Cycles added for F/FA

11/96 Rev E

11/98 Rev F

- Rotor Parts section added
- Estimated Repair and Replace Cycles added for FA+E
- Starts and hours-based rotor maintenance interval equations added

9/00 Rev G

11/02 Rev H

- Estimated Repair and Replace Cycles updated and moved to Appendix D
- Combustion Parts section added
- Inlet Fogging section added

1/03 Rev J

- Off Frequency Operation section added

10/04 Rev K

- GE design intent and predication upon proper components and use added
- Added recommendation for coalescing filters installation upstream of gas heaters
- Added recommendations for shutdown on gas fuel, dual fuel transfers, and FSDS maintenance
- Trip from peak load maintenance factor added
- Lube Oil Cleanliness section added
- Inlet Fogging section updated to Moisture Intake
- Best practices for turning gear operation added
- Rapid Cool-down section added
- Procedural clarifications for HGP inspection added
- Added inspections for galling/fretting in turbine dovetails to major inspection scope
- HGP factored starts calculation updated for application of trip factors
- Turning gear maintenance factor removed for F-class hours-based rotor life
- Removed reference to turning gear impacts on cyclic customers' rotor lives
- HGP factored starts example added
- F-class borescope inspection access locations added
- Various HGP parts replacement cycles updated and additional 6B table added
- Revision History added

List of Figures

GE
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Power Plant Layout Planning – Gas Turbine Inlet Air Quality Considerations

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Power Plant Layout Planning – Gas Turbine Inlet Air Quality Considerations

Introduction

GE heavy-duty gas turbines are able to operate successfully in a wide variety of climates and environments due to inlet air filtration systems that are specifically designed to suit the plant location—while also considering the impact of local air quality variation on the system design. This need for inlet air filtration and the impact of air quality on gas turbine performance and life is discussed in detail in GER-3419A (*Gas Turbine Inlet Air Treatment*).[1]

Under normal conditions the inlet system has the capability to process the air by removing contaminants to levels below those that are harmful to the compressor and turbine. Filtration systems, however, are not 100% effective and an increase in the inlet contaminant concentration will generally result in an increase in the contamination level of the air discharging from the filters. In some circumstances, the location of balance of plant (BOP) equipment or neighboring industrial activities may increase the incoming contaminant concentrations to such a degree that additional precautions may be necessary and require optional filtration or moisture removal equipment.

The purpose of this document is to review steps that may be taken during the initial site layout phase that will help to minimize the impact of local weather conditions and emission sources on the gas turbine's filter system effectiveness. The recommendations contained in this document are not requirements but are suggestions for minimizing the impact of air contaminants. Specific component installation and operating requirements may be found in GE documents that accompany the owner's instruction book.

A checklist is included in the appendix that will help facilitate the layout review process.

Air Quality and Particulates

Particle Size

A recent EPA report describes the current understanding of air quality and particulate emissions in the United States through 2003.[2] In this report, particulates are divided into four categories:

- Supercoarse: > 10 microns
- Coarse: 2.5 to 10 microns
- Fine: 0.1 to 2.5 microns
- Ultrafine: <0.1 microns

Similar surveys are available for other regions of the world, but concentrations and content will be strongly influenced by local topography, climate conditions and degree of industrialization.

Generally, particles larger than approximately 10 microns are less of a health concern and air regulations in the US have concentrated on the PM10 (concentration of particles with a diameter less than 10 microns) and PM2.5 (concentration of particles with a diameter less than 2.5 microns) categories. The particulates of interest for gas turbine applications are typically 3 microns and larger. Particles smaller than 3 microns will remain suspended and tend to follow the gas stream, eliminating issues with deposition or erosion.

Composition

The composition of particulates is wide ranging and will vary considerably with local emission sources. There are, however, general patterns within the US that show in western regions the particulates generally consist of carbon and nitrates and in the eastern region the particulates are largely composed of carbon and sulfates.[2] Seasonal variations are also present, with nitrates peaking in the fourth quarter and sulfate concentrations increasing in the period from July through September. Similar patterns may also be present in other regions and a literature search may provide useful information in preparation for site planning.

Locally, the composition will depend on the source, emission rate, particle size and weather conditions. Coastal regions will have elevated salt concentrations; locations with adjacent industrial or agricultural activities may see increased concentrations of organic and inorganic compounds.

Sources

There are two categories of sources. The *primary source* results in emissions that are discharged directly into the air. This category includes carbon from burning of waste material, forest fires, trucks, cars, quarries, unpaved roads and construction sites, industrial and agricultural processes.

A *secondary source* is one that emits matter that later combines with other material to form particulates or aerosols. Examples are sulfate and nitrate compounds formed from the interaction of SO_2 and NO_x gaseous emissions with other substances in the atmosphere.

Contaminants That Are of Concern to the Gas Turbine

Contaminants may be present in solid, liquid or vapor phase. In addition to contaminants, thermal plumes entrained into the gas turbine inlet air may result in a distortion of the flow at the compressor inlet or may raise the apparent ambient temperature.

Gas Phase Contaminants

In general, gas phase contaminants are only an issue if the source is relatively near the gas turbine, less than approximately one mile. This is because the natural dispersion tendency for gas phase components will quickly dilute the concentration of the contaminant to low levels. Exceptions to this are gas phase contaminants that condense shortly after discharge, forming a plume of aerosol droplet that can be carried by prevailing winds to the gas turbine inlet. These are rare and most likely would be associated with chemical or industrial processes. Gaseous contaminants include:

- Ammonia
- Chlorine
- Hydrocarbon gases
- Sulfur in the form of H_2S, SO_2
- Discharge from oil cooler vents

Solid Contaminants

Contaminants are spread from the source and transported by wind. The larger, denser particles will drop out relatively quickly, within a few hundred feet or less from the source. Particles less than approximately 30–50 microns will continue to remain airborne until the settling rate and turbulence eventually shifts the distribution mean to less than approximately 10 microns.

Examples of common solid contaminants are:

- Sand, alumina and silica
- Rust
- Road dust, alumina and silica
- Calcium sulfate
- Ammonia compounds from fertilizer and animal feed operations
- Vegetation, airborne seeds

Liquid Contaminants

Liquid aerosols may be generated by liquid agitation or condensation of vapor phase mixtures. Common sources are:

- Wave action at coastal sites
- Cooling tower drift
- Condensation of moist exhaust plumes in cold weather
- Petrochemical discharges
- Chiller condensate
- Rain

Contaminants that are commonly found in liquid aerosols are:

- Chloride salts dissolved in water (sodium, potassium)
- Nitrates
- Sulfates
- Hydrocarbons

Moisture droplets are not considered to be an air contaminant, but if allowed to pass through particulate filters, water-soluble salts will be leached from the dust cake and transported to the compressor. The use of static filters designed for liquid removal will minimize this risk.

Exhaust Plumes

The gas turbine inlet is typically isolated from any significant combustion sources. Discharge from small diesels or other combustion equipment should be routed away from the inlet to prevent the possibility of entrainment of the exhaust gas with the gas turbine intake air. A more significant emission source is the thermal plume rising from an air-cooled condenser. While not a contaminant, entrainment of portions of the condenser discharge plume will raise the apparent ambient temperature at the gas turbine inlet and temporarily reduce the base load generating capability. This topic is discussed in more detail in the Air-Cooled Condensers section.

Corrosive Agents

Chlorides, nitrates and sulfates can deposit on compressor blades and may result in stress corrosion attack and/or cause corrosion pitting. Removal of liquid aerosols and dry particulates by filtration will capture the majority of these corrosive agents. As discussed earlier, filters are not 100% effective and small concentrations of contaminants have been observed to deposit and collect on portions of the gas turbine compressor blading. The recommended control mechanism to avoid long-term contact with these and other corrosive deposits is daily on-line water washing.

Sodium and Potassium Chloride

Sodium and potassium are alkali metals that can combine with sulfur to form a highly corrosive agent that will attack portions of the hot gas path. As a salt, sodium and potassium chloride may result in the corrosion of compressor blades if deposits are not removed by water washing at the recommended intervals.

Salt is present in the ambient air and is derived from seawater aerosols carried by the wind. Appendix B describes the mineral content of seawater, which consists of more than 85% sodium chloride. The concentration is highest at the shore and falls rapidly until at a distance of approximately 8-12 miles it reaches an equilibrium value of approximately 2 to 3 ppbw. Concentrations of 0 to 12 miles from the coastline vary significantly with wind speed, direction, elevation and topography. The small aerosols that are carried further inland may eventually evaporate, leaving airborne dry salt crystals. Salt crystals will deliquesce absorbing moisture from the atmosphere and form concentrated brine droplets as the relative humidity rises above 70%. Dry salt crystals will not form until the relative humidity falls below 43%.

Nitrates (Water Soluble or Dry Particulates)

Nitrates are present in fertilizer products that can be released into the air from local agricultural activities. Ground preparation during dry periods can create two potential sources: airborne dust particles and drift carry-over from spray irrigation. Emissions from these sources are likely to be seasonal and may not be present in the air at the time of measurement, usually from analysis of the gas turbine filter catch.

Nitrates may also be released from chemical processing plants but emissions are likely to be controlled to low levels by local air pollution requirements.

Sulfates

Certain sulfates have limited solubility in water and are more likely to be found in the form of particulates in relatively dry climates. Calcium sulfate dust emissions from an adjacent wallboard manufacturing facility, for example, have been found to pass through inlet filters and plug turbine cooling passages.[3] Once recognized, the problem was resolved by upgrading the inlet filters.

Sulfates may also be formed by reaction of atmospheric SO_2 emissions with mineral dust particles. Examples are calcium and magnesium sulfate.

Methods of Removal

Solid Particulates

Solid particulates are removed with self-cleaning (pulse) filters or static filters. These are made from a fabric-type material and are effective over the entire gas turbine operating range with a degree of removal efficiency that varies with particle size. Particulate filters will not remove liquids.

Liquid Aerosols

Soluble alkali salts are removed with coalescing filters. These are also fabric-type filters with a small pore size that is designed to cause agglomeration of liquid droplets that are removed by gravity. Coalescing filters are effective over the entire gas turbine operating range with a degree of removal efficiency that varies with droplet size and filter face velocity.

The condition of the filters may be monitored by measuring the pressure drop and by regular visual inspection. As the pressure drop increases and exceeds the maximum design value, particles will pass through the filters or droplets will re-entrain with the airflow and efficiency falls. If not maintained, the filter elements may ultimately collapse, resulting in a seal failure and allowing contaminated air to by-pass the filter.

In dusty climates, a coalescing pre-filter is used to remove particulates and reduce the plugging rate of the coalescing filter.

Moisture separators may be used in extreme moisture carry-over conditions in combination with coalescing filters. The moisture separator removes the majority of larger droplets while the coalescing filters remove most of the remainder. High performance separators may be constructed from stainless steel or aluminum depending on the application. Drift eliminators may be constructed from plastic materials in the form of a mesh that provides a tortuous path and removes moisture by inertial separation.

Filters will remove approximately 99% of particles and droplets larger than 10 microns and approximately 90% for droplets and particles 4 microns in diameter. As a result, if the incoming particle concentration increases, even with a constant size distribution the air quality at the compressor inlet will decrease.

Gas phase contaminants such as ammonia or sulfur cannot be removed by filtration. As long as these contaminants remain in the gaseous phase there will be no impact on the compressor or hot gas path. Gas phases coming in contact with liquid water droplets from an evaporative cooler will be partially absorbed. A drift eliminator installed downstream of the cooler will remove excess moisture but a very small portion of the original gas phase contaminant will dissolve in the water droplet carry-over.

Gas phases coming in contact with moisture droplets introduced by inlet fogging systems will be partially absorbed and carry over as dilute sulfurous or nitrous acids. These are potentially harmful and may be combined with deposits, increasing the corrosive potential of the deposit. Daily on-line and periodic off-line water washing that follows the recommended schedule will remove the deposits and prevent or minimize corrosion issues.

Gas Turbine Inlet System Components and Function

The section that follows is a brief description of the main gas turbine inlet features. For additional information including the impact of weather conditions and filtration capability, please refer to GER-3419A.[1]

The inlet system is divided into four main components:

1. The intake weather hoods
2. The inlet filter compartment
3. The inlet ducting
4. The gas turbine inlet plenum

Intake Louvers and Weather Hoods

The function of the intake provides a path for air to enter the inlet filter compartment from the ambient surroundings. In relatively clean environments with light weather conditions, intake louvers reduce the concentration of entrained rain droplets and provide rudimentary protection against large objects from striking the filter media.

In regions of moderate to severe weather climates the intake may include weather hoods designed to minimize the entrainment of snow, rain, freezing rain or dust particles. An example of a weather hood is shown in *Figure 1*. Optional moisture separators and coalescing filters can be installed in the weather hoods in regions that experience high humidity and rainfall.

Figure 1. Gas turbine inlet with weather hoods

The weather hoods can be acoustically treated where necessary to minimize the acoustic emissions and meet local code requirements.

Immediately downstream of the louvers or hoods, moisture separators may be installed to remove the majority of entrained moisture droplets. A bank of coalescing filters can be installed downstream of the moisture separators if moisture carry-over from the separators is anticipated to be an issue. Guidelines for the use of moisture separators and coalescing filters may be found in GER-3419A.[1]

Steam Heaters

Self-cleaning pulse filters are effective in preventing ice formation and plugging except in the most severe of icing conditions that, for example, may be associated with cooling tower drift. If static filters are specified, plugging may become an issue in cold climates during periods that are favorable to icing conditions. While pulse filters are the preferred approach for these applications, steam heaters may be installed to provide protection from icing. An additional pressure drop penalty on gas turbine output will be observed year round due to the steam heater. Steam heaters remove contaminants from the air and will increase the moisture present by melting ice or snow that is drawn in through the weather hoods. Synthetic filter media is recommended for these applications where high levels of humidity or droplets may be experienced for extended periods.

Inlet Filter Compartment

The function of the inlet filter compartment is to provide a location for both coalescing and particulate filters. Coalescing filters remove liquids and are configured as replaceable pads located upstream of the particulate filters. The particulate filters may be either static replaceable pads or self-cleaning pulse filters in the form of cylindrical elements. The self-cleaning filters are periodically pulsed by high velocity air from the rear to dislodge the accumulated dust cake. The pulsing sequence is triggered when the measured filter pressure drop exceeds a preset value. The dust falls to the bottom of the inlet compartment and is removed to the outside of the compartment by a rotating auger and seal system for collection and disposal. It is recommend that the static filters be periodically replaced when the pressure drop exceeds a pre-set value. Pre-filters may also be installed to unload the coalescing filters and can be changed on line if necessary. Failure to pulse or replace filters will result in a loss of gas turbine performance and ultimately, failure of the filter elements.

An optional evaporative cooler module is located downstream of the primary filters. The evaporative cooler consists of a honeycomb-type cellulose media structure over which water is constantly recirculated from a collection sump. Water is evaporated from the surface of the media resulting in a reduction in the dry bulb temperature of the inlet air. Fine water droplets may be entrained in the air flowing across the media that is removed by a downstream mist eliminator.

Inlet Duct

The inlet duct is designed to contain the treated inlet air from the inlet filter compartment to the gas turbine inlet plenum. The intake duct contains acoustically treated silencing panels, the inlet bleed heat system, and the trash screen. Internal struts are used to strengthen the inlet ductwork.

Gas Turbine Inlet Plenum

The inlet plenum is located immediately upstream of the gas turbine inlet and contains the compressor inlet bellmouth. The purpose of the plenum is to provide a relatively turbulent-free region at the inlet to the compressor inlet guide vanes. The inlet bell mouth contains nozzles used for on and offline water washing.

Balance of Plant Impact on Gas Turbine Intake Air Quality

Cooling Water Tower Drift

A major localized emission source is the aerosol drift from cooling towers.

The discharge from the top of the cooling towers is warm moist air that is considered pollution-free. In vapor form, the water will not contain harmful chemicals or any solid material that is retained by the re-circulating water and returned to the warm water well at the base of the tower. In extreme cold climates however, the moisture content of the discharge air and ambient temperature may be favorable for the formation of ice fog. Ice fog or freezing fog consists of suspended super-cooled water droplets. The droplets will freeze on contact with solid objects, forming a build up of rime ice in a process that is similar to icing on aircraft wings. If the inlet filters ice up, the turbine will lose power and may eventually shut down due to excessive inlet filter pressure drop. Self-cleaning filters will help prevent ice formation on the filters, but elimination at the source is the preferred approach.

Some cooling tower suppliers offer options that minimize the formation of ice fog clouds, particularly for those installations located near highways where fog and ice would result in a major road hazard.[4] This option should be considered if there is a possibility of ice fog formation that may drift towards the inlet.

In addition to the plume discharge at the top of the tower, there is a secondary discharge from the louvered walls of the cooling tower structure. This discharge is the result of cross winds entraining re-circulating water droplets from within the tower. This effect will be localized and may extend only a few hundred feet depending on the wind speed and droplet size. The drift however may contain concentrated water treatment chemicals that in some cases could be corrosive. Cooling tower manufacturers offer advice on cooling tower orientation to prevailing winds and drift eliminators that can be installed to minimize this problem.

Estimates can be made of the drift and expressed in terms of contour plots of elevated wet bulb temperature. An example of this type of plot is shown in simplified form in *Figure 2*. Cooling towers are located along the southern border of the plant and two gas turbines are located to the north of the cooling towers and the predominant winds are from the southwest. The contours shown

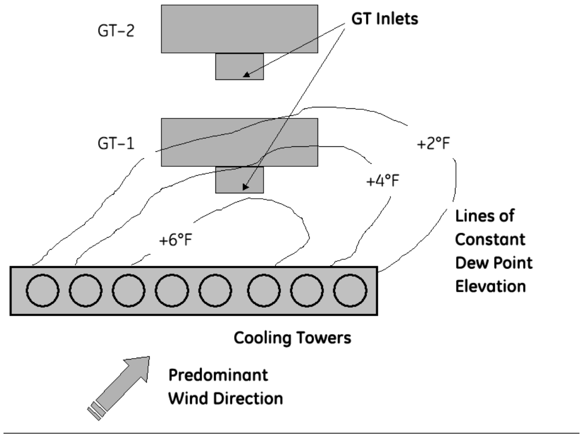

Figure 2. Example of cooling tower drift and gas turbine inlet ingestion

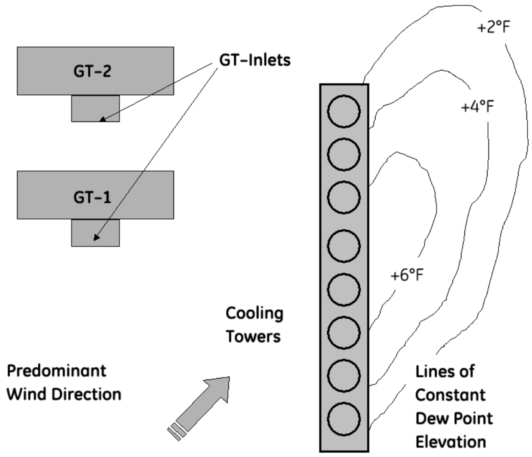

Figure 3. Cooling towers re-arranged to prevent gas turbine inlet ingestion of droplets

are lines of dew point elevation above the surrounding ambient level resulting from the drift from the cooling towers. In this example, GT1 will likely ingest droplets from the cooling towers during a significant portion of the operating period. GT2 will see some impact but will be affected to a lesser extent than GT1.

With this type of information available during the planning phase, a re-arrangement such as that shown in *Figure 3* could be made that would virtually eliminate all possibility of drift ingestion except during periods of unusual wind shifts.

Some coastal sites utilize seawater as the cooling water supply. Sodium chloride in the seawater will become concentrated as the cooling water is re-circulated. Manufacturer recommendations to control water chemistry by the use of additives and sump blow down should be followed to avoid excessive deposits on the tower media and concentration of harmful chemical build up. As discussed in the Corrosive Agents section, sodium is an alkali metal that is a highly corrosive agent and intake ingestion of brine droplets should be minimized as much as possible.

In a description of seawater cooling towers, the author states that the sodium chloride levels can be controlled by blow down to concentrations below 55,000 ppmw without serious scaling issues of the heat exchanger surfaces.[5] At concentrations above 55,000 ppmw, the cooling water pH must be neutralized to minimize deposit formation by adjustment of the water chemistry. In some cases this treatment includes the addition of sulfuric acid. Over-adjustment may result in a carry-over of highly corrosive sulfuric acid mist emitted from the wall louvers of the tower. Consideration should be given to more frequent blow downs if this situation exists to minimize the need for water treatment.

Air-Cooled Condensers

Large volumes of warm air are discharged from air-cooled condensers. When the prevailing winds pass above the cooling air discharge fans, dispersion of the warm air takes place. If the wind speed is of a sufficient velocity and direction—and the location of the gas turbine inlet is near the air-cooled condenser discharge—it is possible to raise the gas turbine intake air temperature by several degrees.

Figure 4 shows a typical air-cooled condenser. Ambient air is drawn in from the bottom by horizontal fans and directed vertically upwards across the heat exchanger tubes. Air flowing across and through the tube bundles removes heat from low temperature steam, resulting in condensation and a rise in the cooling air temperature.

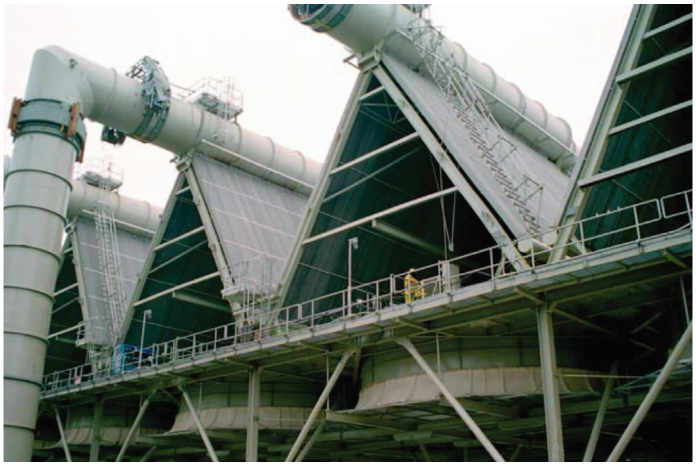

Figure 4. Air-cooled condenser showing horizontal cooling fans and heat exchanger tubes

Winds will pass above the condenser and disperse the heated cooling air. If the gas turbine is in the path of the prevailing wind, then a rise in inlet temperature will be experienced that is proportional to the wind speed and inversely proportional to the distance from the intake to the condenser.

Figure 5 shows an example of how the heated discharge air from an air-cooled condenser could result in an elevated gas turbine inlet temperature.

The increase in inlet temperature will adversely impact the gas turbine output and result in the loss of several megawatts in base load generating capacity. The potential loss in annual revenue could significantly affect profit margins, depending on the severity of the problem.

Figure 6 shows the typical reduction in power output, referenced to ISO conditions, with a rise in ambient temperature, assuming no inlet chilling or evaporative cooling is in effect.

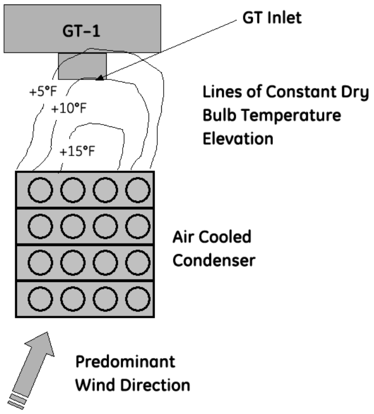

Figure 5. Ingestion of discharge plume from air-cooled condenser

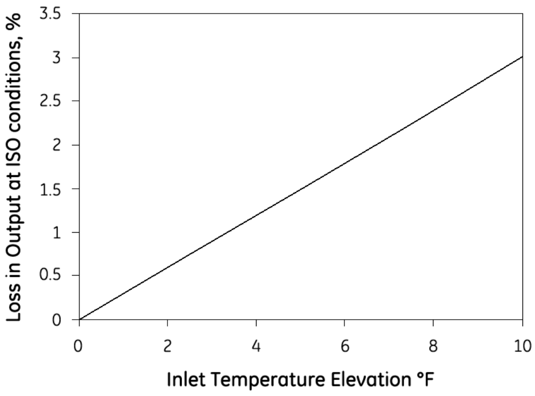

Figure 6. Output loss at ISO conditions resulting from inlet temperature increase

Pressure Relief Valves and Flanged Gas Pipe Joints

Pressure relief valves installed on gas supply lines and process equipment may intermittently or continuously vent natural gas. It is critical that natural gas vents from all pressure vessels are discharged to a safe area well away from the gas turbine air intake. The gas turbine inlet filters will not remove gas phase contaminants and large volumes of entrained gas may lead to turbine control problems and operation leading to out-of-compliance emissions or turbine damage.

Gas, steam or other fluid piping with flanged connections may leak after years of safe operation. By routing piping away from the inlet, the potential issues associated with entrained gases or fluids aerosols with the intake air can be avoided.

Impact of Local Weather Conditions and Emission Sources

The transport mechanism for solid air contaminants is through entrainment of small particles and droplets or dispersion of gases in the compressor intake air. The contaminants are carried by wind currents from their source and drawn into the gas turbine intake.

Particles and droplets are maintained aloft by turbulent air patterns. Depending on the settling velocity of the contaminant and wind speed, the contaminant concentration will gradually decrease along the flow path until a minimum value is reached. The further the source and the higher the settling rate (or dispersion rate for gas phase contaminants), the lower the contaminant concentration.

Winter Lake Effects

One of the most common localized weather effects in the US is observed on the eastern shores of the Great Lakes during the early winter. At this time the water temperature may be above the ambient air temperature and evaporation takes place from the surface of the lake. Cold air from the north combines with the moisture, becomes rapidly saturated and leads to the formation of snow and ice crystals, creating lake-effect snowstorms. The lake-affected region may extend from a few miles to 50 or 100 miles from the shoreline depending on the time of year, lake temperature, wind direction and strength. Large quantities of snow may precipitate in a few hours. For these locations, careful orientation of the air inlet intake away from the prevailing fall and early winter winds will help to minimize the ingestion of snow and ice crystals. The impact of local buildings, walls, roofs fuel tanks or other obstructions that may re-direct wind towards the inlet or create a snow fence effect that deposits large quantities of snow near the inlet should also be considered.

Coastal Effects

Most coastal locations will experience onshore winds all year or part of the year. GER-3419A reports that at locations within 8 to 12 miles of the coast the concentration of sea salt droplets in the atmosphere will increase with wind speed and nearness to the shoreline.[1] At distances of 100–200 feet, the concentration will rapidly increase due to the entrainment of larger droplets produced by the wave action of the surf. Further inland beyond approximately 8–12 miles, the alkali salt concentration falls and remains essentially constant except in extreme weather conditions or in the presence of local sources such as dry lakebeds or heavily salted highways.

Inland Dry Lake Beds

Dry lakebeds are a potential source of alkali salts. They are typically found in dry desert climates and the salt is entrained in the air as a solid particulate. If static filters are used and the weather conditions are seasonably variable, there is a possibility that the salt particles trapped on the static filter will deliquesce, absorbing moisture as the relative humidity exceeds 70%. The soluble salts will then pass through the filter in droplet form and enter the compressor and hot gas path. To minimize this impact, self-cleaning filters are recommended for this situation. While salt particles will build up on the filter, they will be periodically removed during the pulsing cleaning process, limiting the carry-over during periods of high humidity.

Inland Salt Lakes

Inland salt lakes will have a similar impact on air quality as coastal locations, except the aerosol production from wave action will be less. This will be offset, to some extent, by the naturally higher saline concentration of inland lakes produced by evaporation.

New Emission Sources

New emission sources may result from nearby new construction or a change in local industrial or agricultural activities. In some cases the new source emissions may be obvious; in others involving colorless gaseous or trace metal emissions, the new source emissions may not be immediately recognized. If a new local emission source is suspected, plant owners should consider performing an air quality survey to confirm or eliminate the need for action or additional protection.

ISO Standards for Classification of Corrosive Atmospheres

The International Standards Organization has developed a standard for classifying the corrosivity of an atmosphere, ISO 9223.[6] It is based on the presence of sulfur dioxide, airborne chlorides and the time the location is exposed to moisture, defined as the time of wetness. Five classifications are identified, C1 through C5, ranging from very low to very high. The classification is determined from the concentration of sulfur dioxide and airborne chlorides and the time of wetness. The time of wetness is similarly classified as T1 through T5, ranging from indoors to tropical outdoors or surf. The classification is expressed in terms of a 1-year corrosion rate in g/m^2 for various metals. In addition, the following three other standards are used to supplement ISO 9223:

- ISO 9924[7] provides guidance on corrosion values, terms and definitions for categories defined in ISO 9223
- ISO 9925[8] provide methods for measuring deposition rates of sulfur dioxide and airborne salts
- ISO 9226[9] specifies preparation of test specimen coupons, exposure and expression of results

The ISO classification method is useful for evaluating the corrosivity of an atmosphere, particularly for static structures and can provide guidance for determination of the need for protective coatings or alternate material selection. It is not directly applicable to gas turbine internal components that are exposed to vibratory stresses and frequent water washing, but does provide some insight to the relative corrosivity potential.

Plant Layout Considerations

When considering the plant layout, year-round ambient conditions and the influence on air quality of nearby large bodies of water (salt or fresh water), industrial or agricultural operations, cooling towers or others sources of moisture should be considered. The potential air quality variations will impact the operational efficiency of the gas turbine inlet filtration system. An inlet system that is designed primarily for dusty climates, for example, may not perform well if steam or water droplets are continuously entrained with the gas turbine inlet air.

Questionnaire

GE can assist with the selection of suitable inlet options for a given range of expected site air quality conditions. To aid with this task, a questionnaire has been developed that will provide the basic information required to determine the type of inlet filtration system best suited for the application. After a review of the site conditions, additional information may be requested before the design is finalized. The questionnaire may be found in Appendix C. Customers are encouraged to include additional information that may impact local air quality but not specifically requested.

The following provides background information on why the topics covered in the questionnaire are critical to providing proper protection to the gas turbine.

Distance to the Nearest Coastal Water

For all coastal locations, the entrained salt in the ambient air will be in droplet form. As discussed earlier, the concentration will vary significantly with distance from the source, the prevailing wind direction and speed. Beyond approximately 8 to 12 miles from the coast, the ambient salt concentration falls to a typical inland average value of 8 ppbw (an average sodium equivalent of 2.6 ppbw).

For further details of costal effects on ambient salt concentration refer to GER-3419A.[1]

Dry Lake Beds

Salt originating from inland dry salt-lake beds may be in particulate form for portions of the year and liquid form at other times as the relative humidity rises and falls. Because there is no wave action to generate aerosols, the issue may be less severe than in coastal regions. Periods of high winds and a prolonged dry climate however will contribute to the generation of airborne salt particles. The use of self-cleaning filters is better suited to these conditions if the climate remains dry, since the filter cake is periodically removed. If the humidity rises or rain occurs after a long dry period, the increased moisture content will extract salt from the filters in a liquid aerosol form. Static filters will retain significantly more salt than self-cleaning filters for a given inlet concentration, but may be acceptable if the overall ambient salt concentration is low.

Heavily Traveled Highways

Highways are a source of particulates generated by the passage of traffic. In northern climates where road sand and salting is common to provide traction in winter weather, the carry-over of salt aerosols or particulates must be addressed.

Neighboring Activities

The following are examples of neighboring activities that may produce air contaminants that are potentially harmful to the gas turbine flow path or may result in rapid filter fouling:

Agricultural activities

- Dust
- Plant material processing by-products
- Pesticide drift
- Fertilizers – nitrates, phosphates
- Spray irrigation drift
- Animal feeding by-products

Coal Fired Power Plants

- Fly ash
- Coal dust

Industrial Plants

- Fertilizer manufacturing and processing
  - Ammonia
  - Phosphates
  - Nitrates
  - Calcium
- Wallboard manufacturing[3]
  - Calcium sulfate
- Metal smelting
  - Waste products – slag piles
- Mining activities
  - Coal, closed pit
    - Coal waste from slag piles

  - Coal, strip mining
    - Dirt, dust, coal
  - Open-cast, metal ore
    - Mineral dust, metal ore
- Petrochemicals
  - Sulfur emissions
  - Hydrocarbons emissions
- Waste incinerators
  - Heavy metals
- Waste recycling and reclamation
  - Airborne "fluff" from automobile crushing

Meteorological Data

Meteorological data records are available from numerous sources, including local airports, universities and web sites. It is important, however, when reviewing the data that the plant local conditions are considered. Average wind speeds and direction may not correspond well with airport data taken 10 or more miles away due to changes in elevation and differences in the local terrain. This is particularly important when considering drift from local cooling towers or nearby emission sources. To provide reliable data for plume modeling, it may be necessary to take several months of data using an on-site weather station. If a good correlation can be obtained with data from a local airport or other local weather records, the expected monthly variations can be extracted from historical data.

The following maximum, minimum and average meteorological information must be obtained on a monthly basis:

- The predominant wind speed and direction
- Dry bulb temperature
- Relative humidity
- Rainfall
- Snowfall

If possible, the frequency of fog formation and icing conditions should also be provided.

Air Quality Survey

An air quality survey can be conducted prior to new plant construction or additions. The results from the survey will help with inlet selection and establish a baseline for future reference. This data will be useful if new emission sources are introduced nearby that subsequently require additional inlet protection or that may lead to legal action against the emitter.

There are a number of consulting companies that offer air quality survey services, or air-sampling equipment may be purchased if frequent samples are required. Air quality will vary with weather conditions, including wind speed and direction. It is important that air quality surveys be performed when the prevailing wind is from the direction of the suspected contaminant source. Several air quality samples may be required over a period of several days or weeks if the emission source is not immediately apparent.

The potential air contaminants that are of interest are shown in *Table 1*.

Specie	Phase	Source
Na	Solid or liquid[a]	Sea Water Aerosols
K		
Cl		
Ca	Solid, Partially Soluble	Quarrying, Industrial Manufacturing
S	Solid or Liquid[b]	Petrochemical Processing
Phosphates	Solid or Liquid	Fertilizers
Nitrates		
V	Solid	Industrial Manufacturing
Pb		
Mg		

(a) Mostly present as sodium or potassium chloride. Can be a solid in dry climates relative humidity < 43% or as a dissolved salt in liquid form, RH > 70%

(b) Can be present as a sulfuric acid liquid aerosol, as a calcium sulfate solid particulate. Gaseous forms such as H_2S, SO_2, SO_3 etc., may also be present

Table 1. Potential airborne contaminants

Batch Filter Sampling

Air quality measurements can be performed using batch type filter sampling devices or by means of a continuous air sampler. Filtration type instruments work well but the results may only be representative of air quality at the time that the sample was taken. Judgment is required when to take samples in order that average and seasonal peaks can be identified with reasonable accuracy. Some guidance on this topic is provided in ASTM D1357.[10]

The main purpose of filter sampling is for the catch to be analyzed and compounds identified. The mass concentration and, to some aspect, the contaminant species, will depend on the local weather conditions, possibly requiring multiple samples.

Information on the method for using a high volume filtration sampling system and general procedures may be found in an EPA report,[11] ASTM D4096,[12] and ASTM D3249[13].

Useful information on common terminology used in air sampling practice may be found in ASTM D1356.[14]

To obtain an understanding of the air quality variation throughout the year, frequent samples must be taken, particularly when the prevailing wind direction and speed changes are significant. Local wind speed will vary daily, weekly and monthly, making this type of measurement tedious and time consuming. If the local sources of contaminants are well known—cooling tower drift, for example—sampling frequency could be reduced by monitoring air quality when the prevailing winds at the gas turbine inlet fall within a quadrant that is in line with the emission source. This approach will not provide a complete understanding of the air quality at the site, but will provide an indication of the maximum contaminant concentration and composition.

Continuous Mass Concentration Sampling

Continuous mass monitoring air sampling is preferable in order to correlate air quality with weather conditions. At least one commercially available continuous monitoring instrument is available.[15] This instrument measures mass concentrations, but does not identify species. It may be combined with a programmable filter system that can be triggered by wind speed, direction, concentration or other digital input.[16] The filters can be analyzed to identify species that were captured during the periods that are of interest.

It is important to take meteorological measurements simultaneously in order to correlate the impact of wind speed, direction, etc., on air quality. It is also important to note the operating status of any local equipment or process that may be a potential emission source.

Recommendations

Field experience has shown that corrosion and plugging of filter and hot gas components by contaminants contained in the ambient air can become an issue that adversely affects maintenance intervals. In many cases these issues can be minimized or avoided by appropriate planning during the site layout phase. The following section includes suggestions for key engineering studies that will be beneficial in assessing risks and developing optional arrangements. For additional recommendations, see the checklist in *Appendix A*.

Satellite Imagery

Prior to preliminary site layout planning, it is recommended that satellite imagery of the surrounding region be studied. Several subscriber-based commercial services are available as well as free services. The subscriber services typically offer enhanced resolution to as little as two meters or less. The images can provide additional information to that available from local sources and are relatively inexpensive.

Survey of Local Industrial or Agricultural Operations

Prior to locating the gas turbine inlets, a survey of the local industrial or agricultural activities and terrain should be performed to understand the potential for air contaminant carry-over. Agricultural activities, for example, may generate contaminants for short periods once or twice per year that are rich in nitrates.

Industrial emissions are more likely to be year round and ingestion can be minimized by proper location of the inlet. In an example reported by Johnson and Thomas an adjacent wallboard plant resulted in an elevated concentration of very small calcium sulfate particles that passed through the conventional particulate filter.[3] The particles plugged the turbine cooling passages and caused hot gas path damage that was subsequently prevented by installation of an improved filtration system.

A unit located on a steep hillside with the inlet facing the hill may entrain a higher quantity of wind blown dust and other contaminants because the effective height of the inlet is essentially at or near ground level. This may significantly decrease the life of the filters and increase maintenance frequency. GER-3419A states that particulate concentration may decrease by a factor of 2:1 above an elevation of 20 feet.[1] Where possible, the intake to the filter house should face away from the hillside. Other factors such as prevailing winds must also be taken into account and a compromise solution may be necessary

Severe icing of pulse filters has been reported in which the turbines were located downwind of the cooling towers. During certain periods of the winter months, drift from the cooling tower resulted in the formation of ice fog that deposited rime ice on cold surfaces and the filter media. Where possible, the gas turbine intakes should be located outside of the expected plume originating from cooling towers and other industrial or thermal processes.

CFD Modeling

Computational fluid dynamic modeling can be used to determine the impact of weather conditions and emission sources on inlet air quality. Reports of contaminant concentrations measured in mass/unit area/unit time are useful indicators of a potential problem, but do not take into account the sink effect of the gas turbine drawing in large quantities of air from the surroundings. This will greatly increase the contaminant mass passing through the compressor and turbine in a given time than would otherwise be estimated from a simple surface concentration and settling rate calculation. Cooling tower drift and contaminants from emission sources can be modeled to explore the potential impact on filtration requirements. Similarly, the increase in inlet temperature resulting from the partial entrainment of the discharge of an air-cooled condenser can be modeled to determine the expected annual loss in total output and to identify and justify equipment re-arrangement prior to construction.

In another example where CFD would provide some insight, a turbine inlet was located facing a wall in a region of known heavy snowfall. The geometry and orientation of the wall was such that it acted as a snow fence, causing significant accumulation of snow being deposited and drawn into the gas turbine inlet. Modeling of this type of configuration could help identify potential issues prior to construction and avoid costly field modifications.

Air Quality Survey

The details and types of air quality surveys are discussed in a prior section. The purpose of performing a survey prior to layout planning is to identify the concentration and sources of suspected contaminants. This is particularly important in heavily industrialized localities where there may be a variety of contaminant types and sources. Surveys must be combined with measured weather data to be of use and may require several months of planning with periodic measurements if large seasonal changes are expected.

Site Planning

A review of local emission sources and weather conditions is recommended during the plant preliminary layout phase. By taking these factors into account, location and orientation of the gas turbine intake can be arranged to minimize the impact of known corrosive agents on the inlet filtration system and turbine components. Field modifications to an installation after an air quality problem has been recognized will likely be expensive and require an extended outage. In addition, the final result may not be as effective as appropriate site planning and locating of balance of plant equipment.

Summary

As gas turbine materials engineering and design techniques improve, greater performance and maintainability benefits are realized. Experience has shown that along with these gains there is need to better protect the internal components from erosion and corrosion. In order to meet expected maintenance intervals it is necessary to remove solids and liquids that are considered harmful to the compressor and turbine flow path. Advances in filtration technology, media materials and system design are able to provide the necessary protection from most naturally occurring airborne contaminants. Emissions from local sources, however, may increase the concentration levels downstream of the filters significantly. With careful site planning and consideration of the impact of these on and offsite sources, the effect on gas turbine overall performance can be minimized. A failure to do so may result in costly field modifications, repairs and loss in revenue.

Appendix

A. Checklist

The following simplified checklist is intended as an aid for the preparation of site layout plans. It is recognized that many factors such as available space, access roads, and cooling water access may have a higher priority and dictate the orientation and relative location of the gas turbine and auxiliary equipment. The information provided below, however, will help to minimize intake contaminant concentrations and offer some long term benefits if applied judiciously.

Preliminary Checklist for Preparation of Site Layout Plans	
1	Obtain meteorological data showing the prevailing wind patterns, speed, relative humidity, dry and wet bulb temperature, rainfall and snowfall throughout the year.
2	Identify potential sources of particulate, liquid and gaseous emissions both on site and off site.
3	Locate the off site sources on the plot plan showing distance, direction, known or expected emission type and concentration.
4	Develop plume models for each significant on and off site emission source for each predicted major wind shift, i.e., seasonal variations.
5	Show plan and elevation concentration contours.
6	Perform CFD modeling in the region around the gas turbine inlet to estimate the potential for elevating the concentration at the filter inlet.
7	If some concentration levels appear consistently higher than normal ambient levels, identify the emission source and consider relocating the source or install barrier walls to minimize carry-over to the turbine.
8	Contact GE Application Engineering staff to determine the best inlet configuration for this application.

B. Seawater Composition

The salinity of seawater varies significantly depending on the water temperature. The salinity is defined as the total dissolved solids measured in grams per kilogram, or parts per thousand by weight (pptw). In the Baltic Sea it is approximately 7 pptw (7000 ppmw) and that of the Red Sea is approximately 45 pptw (45 ppmw). An average composition is generally taken as 35 pptw (35000 ppmw). Of this, approximately 85.6% is sodium chloride and 30.6% is sodium. Potassium is approximately 1.1%. Seawater aerosols produced near the ocean before evaporation contains an average of 11100 ppmw of sodium plus potassium.

C. Site Questionnaire

The following questionnaire is intended to provide GE with pre-proposal information concerning local air quality conditions that impact the design of the inlet air filtration system. An understanding of the site environmental conditions is critical to the selection of an efficient and robust filtration system.

Location		
1.	**Is there sufficient information available to categorize the corrosion potential by ISO 9223?[6] If not, or in addition, is there information available concerning the following?**	
	a. Corrosive chemicals are known or may be present:	
	Coastal, within 12 miles of surf	
	Heavy industrial	
	Agricultural with spray irrigation, frequent harvesting, soil preparation	
	Dry salt lake nearby	
	Other	
	b. No known corrosive chemicals present:	
	Inland, rural	
	Light industrial	
	Light agricultural	
	Desert	
	Other	
Local Emission Sources		
2.	**List nearby (< 2 miles) potential sources of particulates:**	
	Coal piles	
	Major highways	
	Reclamation centers	
	Mining operations	
	Foundries	
	Sawmills	
	Wallboard manufacturing	
	Agricultural activities	
	Other	
3.	**List nearby (< 2 miles) potential sources of liquid aerosols:**	
	Cooling water towers	
	Spray irrigation systems	
	Petrochemical processing	
	Other	
Weather		
4.	**What are the monthly average, maximum and minimum values for the following?**	
	Wind speed	
	Wind direction (wind rose if available)	
	Relative humidity	
	Temperature	
	Rainfall	
	Snowfall	
	Fogging conditions, number of days	
	Icing conditions, number of days	
Additional Emission Sources		
5.	**List additional emission sources not included above.**	

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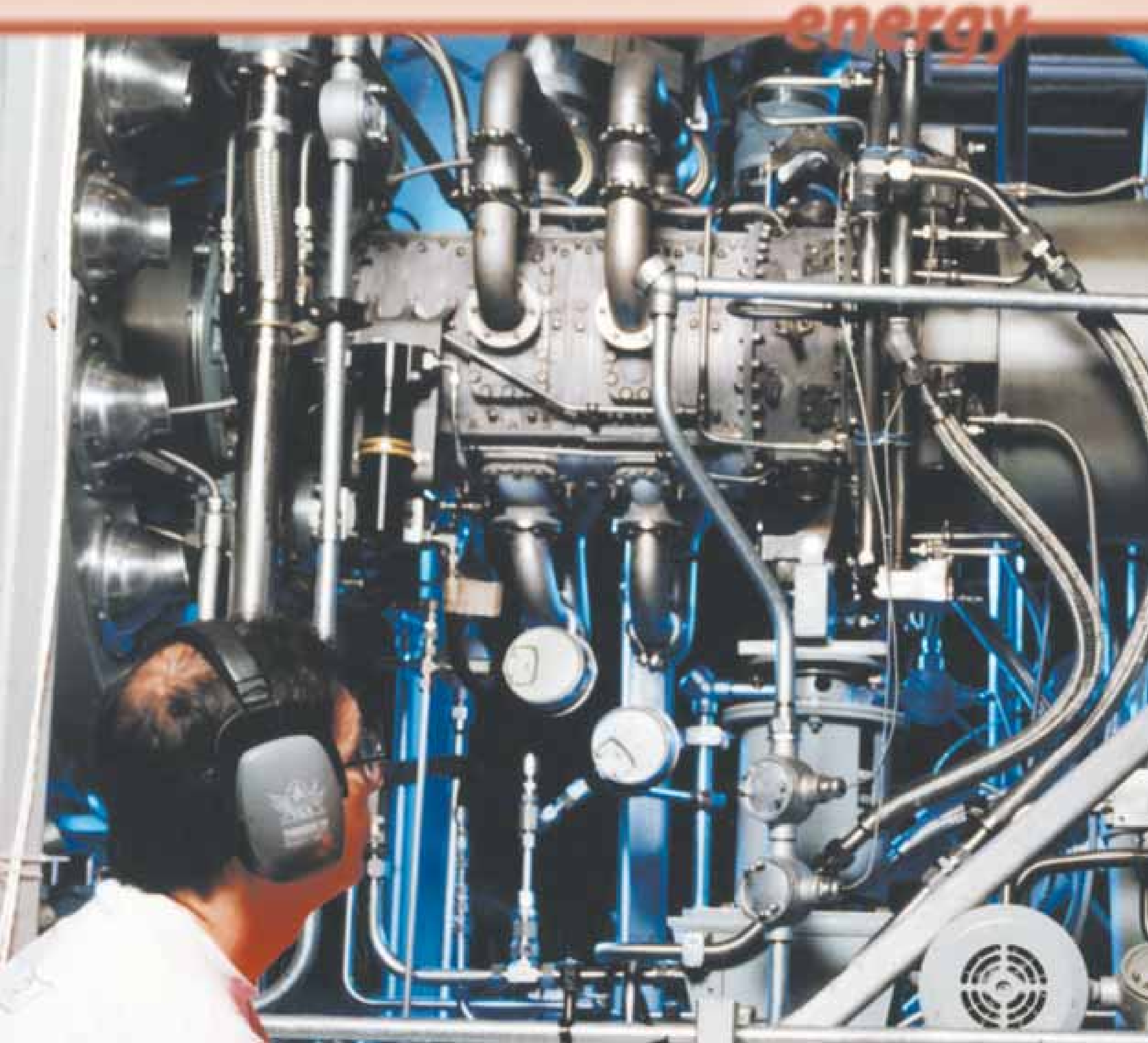
Rolls-Royce

501 Gas Turbines

Performance demonstrated by success



energy

Power proven in flight, trusted on

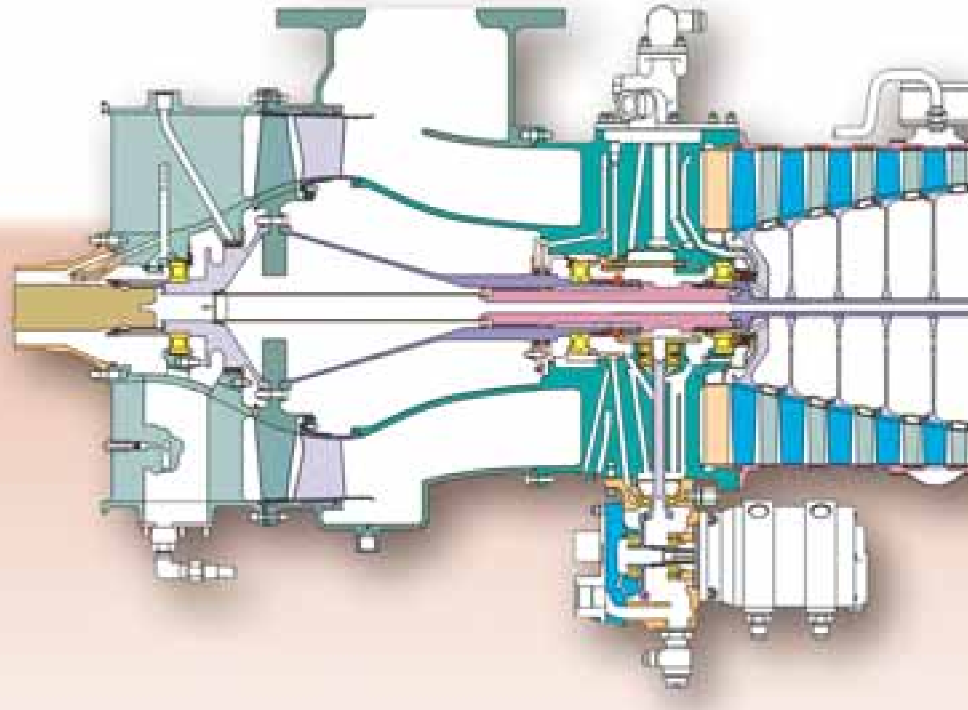
More than 2,500 Rolls-Royce 501 gas turbines have been supplied for industrial use, accumulating an impressive 65 million operating hours with 500 customers in 40 countries. This success is testimony to the efficiency, ease of maintenance and high availability delivered by the dependable 501 design.

The Rolls-Royce 501 gas turbine provides power output between 4.1 and 6.15 MW (5,500 and 9,050 HP) for applications such as pipeline transmission, gas storage and withdrawal, field gas compression crude oil pumping, power generation for onshore and offshore, as well as combined cycle and cogeneration.

Based on the proven T-56 turboprop flight engine, recognized for its reliability in the Lockheed Martin C-130 Hercules transport aircraft, the industrial 501-K owes some of its key features to this aerospace heritage: lightweight modular construction, ease of field repair, limitless starts and stops with the capability of using a wide range of fuels under any environmental condition.

The success of design flexibility

The single-shaft version, 501-KB, is designed for power generation and fixed speed mechanical drive applications. A two-shaft version, the 501-KC, is ideal for driving pumps and centrifugal compressors, which require a wider operating speed range. The boosted (KB7 and KC7) and unboosted (KB5 and



Operating benefits

Longer life – improved temperature profiles and uniform fuel injection.

More corrosion resistance – pin fin vanes incorporated into the first stage increase the cooling area effectiveness of the gas generator turbine vanes, with advanced coating material to provide superior oxidation and hot corrosion resistance.

Improved performance – turbine performance is improved due to improved flow path.

Extended life – state-of-the-art coating on turbine foils demonstrates longer life.

Updated design – low emission combustion liners designed to increase life of hot path components.

Low emissions across wide operating range – intrinsic to the proven Rolls-Royce Dry Low Emissions design, emissions on all 501-K models are held within a tightly controlled range throughout operating condition variations.

Efficient gas compression packages – high-efficiency Cooper-Bessemer pipeline compressors designed to match 501-K power and speeds.

API-Compliant – Built to stringent API-616 standards.

Rolls-Royce

land and sea.

KC5) versions provide power capability between 4.1 and 5.5 MW (5,500 and 7,400 HP) for both power generation and mechanical drives.

The unboosted 501-K uses fourteen stages of compression to maximize flexibility of operation. The boosted versions utilize an additional compressor boost module in front of the main compressor to achieve higher mass flow and pressure ratios resulting in a power and efficiency boost. Compressor bleed valves assure safe starting and optimum performance over the entire load/speed range.

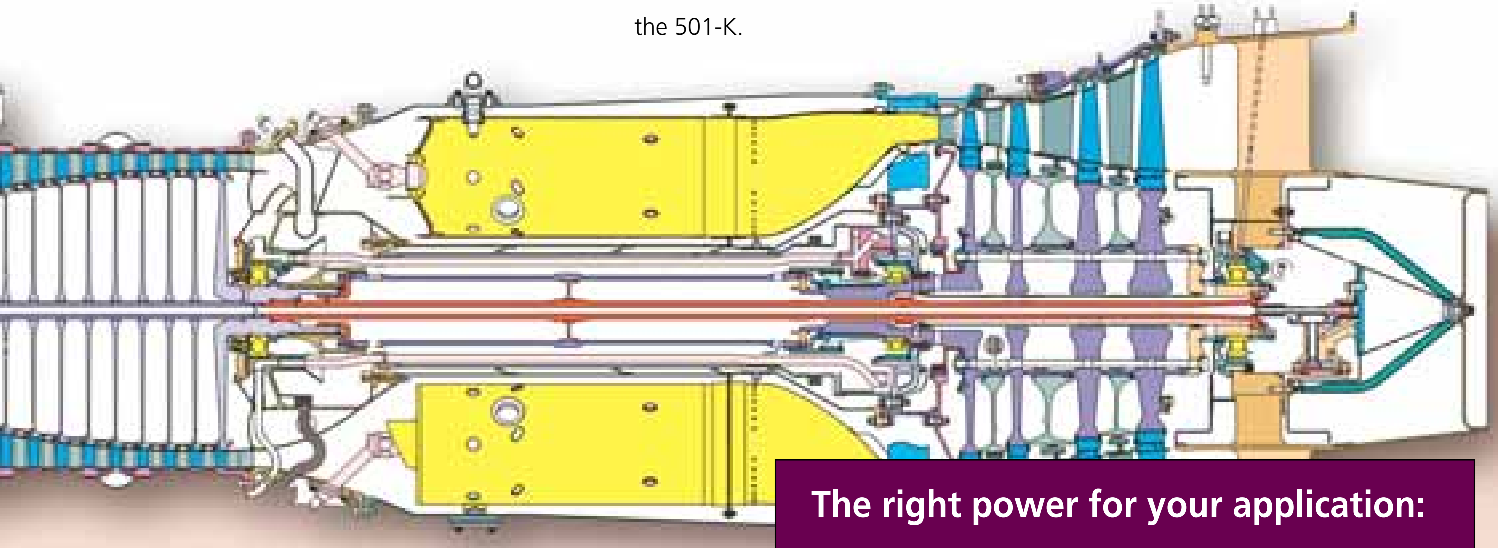
The first two turbine stages drive the gas generator. Two additional turbine stages provide power to drive generators, compressors and pumps. The steam-injected, single-shaft 501-KH5 provides power above 6.5 MW (9,050 HP) at an efficiency unprecedented for gas turbines of this size.

Fuel options

Six combustion cans, which can be fitted with a multitude of different fuel nozzles, allow operation on gas, liquid, dual fuel, low BTU fuels, steam and water injection. Dry Low Emissions (DLE) is available on the 501-K.

Compact design, common components.

The 501-K gas generator is typically less than 2.7 meters (8 feet) long and weighs less than 766 Kg (1,690 lbs.). This compact design offers application versatility, while 501 variants share a majority of common components to simplify maintenance and parts inventory.



The right power for your application:

Model	KW	HP
501-KB5	3,938(e)	–
501-KB7	5,300(e)	–
501-KC5	4,100	5,500
501-KC7	5,500	7,400
501-KH5	6,420(e)	–

Technology and experience drive continual improvements

As a global leader in the production of a broad line of turbines for critical applications as varied as aerospace, defense, and marine, as well as the energy industry, Rolls-Royce dedicates unmatched engineering and operating expertise to applying technology advancements to new and existing products.

Tempered by a healthy respect for the strong basic design advantages that are the foundation of the 501 gas turbine success, proven material and component advancements are continually applied to all 501 gas turbine models. Many of these enhancements are invisible to the operator, like advanced coating materials on crucial parts to provide an even longer operating life. Because the Rolls-Royce commitment to enhancing performance extends throughout our equipment's life cycle, technology-based updates are also available in retrofit format for 501 turbines currently in service.

Packaged for Success

Power generation applications

The 501-KB5 and the boosted 501-KB7 have demonstrated reliability in power generation applications for offshore platforms, onshore gas production, stand-by power and cogeneration.

Applications	■ Combined cycle, cogeneration, stand-by power, primary power.
Common Skid Design	■ Both 501-KB models packaged on the identical skid, same interfaces, for simple on-site switch of gas turbines. ■ Economical on-site upgrade from 501-KB5 to 501-KB7 as power needs to be increased. ■ All ancillary and auxiliary equipment indentical on the common skid.
Gear	■ Epicyclic gearbox face mounted in the generator for a close-coupled solution impervious to misalignment. ■ High-speed power output shaft directly connected to high-speed end of gearbox. ■ Durable steel, easy internal inspection, same gearbox frame for both 501-KB models. ■ Pre-designed gear wheel sets for 50 and 60 Hz reduce delivery lead times.
Driven Equipment	■ Generator – Typically open drip proof design and 4-pole construction. ■ One frame size provides for both the rotor and starter of both 501-KB models. ■ Alternator can be designed for frequencies, voltage and powers specific to project.

Compressor and pump drive applications

The 501-KC5 and the boosted 501-KC7 have a proven record of providing reliable power for driving compressors and centrifugal pumps in the oil and gas industry.

Applications	■ Pipeline transmission, gas storage and withdrawal, field gas compression, waterflood, crude oil pumping, for onshore and offshore.
Common Skid Design	■ Gas generator, power turbine and all auxiliary systems packaged on a single skid. ■ Both 501-KC models packaged on identical skids with same interfaces. ■ Quick field upgrades, simplified maintenance and operation, minimal spare parts inventory.
Connection	■ Flexible coupling between the power turbine and driven equipment designed to API-671. ■ Couplings do not require lubrication, impose no excessive axial or radial loads.
Driven Equipment	■ Compressor – Cooper-Bessemer pipeline and barrel compressors designed to match 501 gas turbine power ratings. ■ Highest efficiency pipeliner in the industry, Cooper-Bessemer RFA24, also available. ■ Other manufacturer’s compressors available.

Package features for all applications

Lubricating Oil System	Provides synthetic oil to gas turbine, power turbine, gear and driven equipment for higher durability and longer life than mineral oil. Main lube pump driven off the turbine for normal operation and shutdown. Auxiliary pump for backup. Oil system components skid-mounted, designed to API-614 standards. Optional heaters/coolers to meet the climate needs of the application.
Fuel System	On-skid fuel system includes all components needed to control fuel during start-up and operation. Operates on natural gas, liquid, dual fuel, low BTU, steam and water injection.
Low Emissions	Dry Low Emission (DLE) system available on 501 variants; both power generation and mechanical drive applications. Maintains stringent emission levels across wide range of operating conditions.
Start Systems	Emission-free start capability with on-skid VFD electric and hydraulic-electric start. Overrunning clutch disengages when self-sustaining speed is reached.
Baseplate	Sturdy but small lightweight footprint. Design allows easy access for maintenance. Jib boom provides easy removal or installation of gas turbine.
Electrical & Plumbing	Stainless steel on-skid piping and tubing improves corrosion resistance. All on-skid cabling wired to junction boxes; CSA, NEC and IEC standards can be observed. On skid instruments generally in accordance with Div.2 or Zone 2 classifications (depending on codes specified for project).
Air Intake System	Provides clean, uniform airflow to gas turbine. Includes filter assembly, silencer and flow direction geometry Site-specific design minimizes disruption of inlet air. Filtration systems available to handle site extremes—arctic cold, water spray entrained with salt, severe heat and dust. Single to multiple stages handle offshore, coastal and inland sites.
Gas Turbine Enclosure	Acoustic enclosures meet wide range of requirements and environments. Factory-completed enclosure can house all auxiliary equipment on turbine skid, with piping and wiring completed and tested at factory. Completed enclosures shipped with connections intact for simplified installation and commissioning.
Water Wash System	Maintain performance by preventing build-up of contaminants in gas generator compressor. Pump or compressed air system includes storage tanks, pressure gauges, valves, piping.

Complete capabilities

Factory testing

Rolls-Royce has extensive test facilities in both North America and Europe to ensure that each unit conforms to exacting performance objectives. Each gas generator undergoes a full speed, full load test run at the Rolls-Royce facility. Then the packaged gas turbine is given a full speed, no load test run prior to shipment.

Operation full load dynamometer testing to ASME PTC-22 can be conducted using either liquid or gaseous fuel over the complete range of speeds and load of the 501 gas turbine family. Complete package full load and emissions string testing is also available. In this case the actual driven equipment (compressor, pump, or AC generator) is used for loading to ensure that all package performance objectives are met.

Automation and control systems

Rolls-Royce provides complete automation and control solutions for 501 gas turbines, including the En-Tronic® family of control systems as well as commercial (off-the-shelf) PLC's. En-Tronic programmable modules allow real time monitoring of gas turbine speed, sequencing, surge, governor and lubrication control.

Easy-to-use software permits the fine-tuning of set points and variables within the system memory. This allows control, start/stop and lead unit select routines and loading/unloading steps to be programmed into the system to achieve operation at the lowest possible cost. Precise digital fuel control provides optimum fuel efficiency.

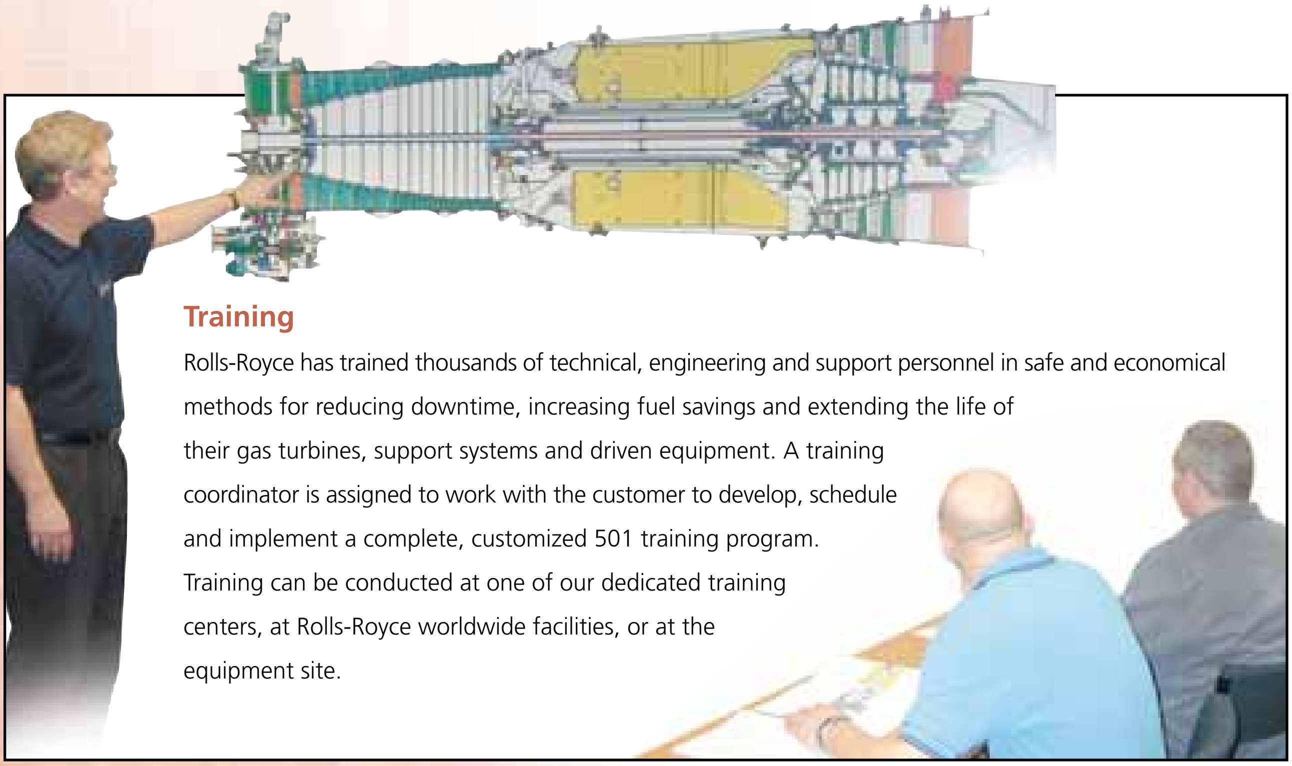
Availability is maximized using display, logging and maintenance information, which allows operators to evaluate unit history and plan shutdowns to coincide with other plant maintenance. En-Tronic control systems are also available for load shedding for multiple power generation units and complete pipeline station controls for compressor drives.

Product support/customer services

Support services are provided through our dedicated Rolls-Royce customer services organization. Our worldwide technical staff and experienced engineers, as well as strategic location of inventoried spare parts, assure quick response time. Lease and exchange engines are available through our "power by the hour" program. Rolls-Royce also provides overhaul and repair services through our joint venture, the Rolls Wood Group, as well as a number of affiliated authorized maintenance centers.

Solutions for the future

At Rolls-Royce, we are continually working today to increase the range and scope of customer service solutions in order to meet tomorrow's challenges. A prime example of this commitment to the future is our on-line service community at **www.energymanager-online.com** which provides customers with access to our technical documentation every second of every day!



Training

Rolls-Royce has trained thousands of technical, engineering and support personnel in safe and economical methods for reducing downtime, increasing fuel savings and extending the life of their gas turbines, support systems and driven equipment. A training coordinator is assigned to work with the customer to develop, schedule and implement a complete, customized 501 training program. Training can be conducted at one of our dedicated training centers, at Rolls-Royce worldwide facilities, or at the equipment site.

Rolls-Royce

501 maintenance centers

Regional Sales Offices

Americas-North America
10255 Richmond • Suite 101
Houston, Texas 77042 • U.S.A.
Telephone: (713) 273-7700 • Fax: (713) 273-7777

Americas-South America
Av. Almirante Barroso 52, 9th Floor,
20031-000, Rio de Janeiro, Brazil
Telephone: (00) 55 21 2277 0100 • Fax: (00) 55 21 2277 0168

Asia Pacific
16 International Business Park
Unit 03-09, Singapore 609929
Telephone: (65) 6899 0092 • Fax: (65) 6862 4495

Europe/Middle East/Africa
5, Mondial Way • Harlington, Hayes
Middlesex UB3 5AR • United Kingdom
Telephone: 44 (0)20 8990 1900 • Fax: 44 (0)20 8990 1911

Note: Standard equipment, specifications and data are subject to change without notice.

GE Energy

Power Plant

Near-Field Noise Considerations

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CONTENTS

Foreword

The following document has been prepared for use during discussions of common questions and issues regarding noise in Power Plant applications. Expected readers include GE Customers, GE Partners and internal GE organizations not involved with the subject of noise on a regular basis.

Our intent is to present brief, easily understood explanations and examples, which may be used for clarification of discussion points which may arise during communication with GE Customers and Partners.

The two sections of this document address common subjects, which are frequently discussed during these communications:

Section I – Power Generation Equipment and Other Factors Concerning the Protection of Power Plant Employees Against Noise

Addresses: Responsibility for compliance to noise-related Health and Safety regulations. The decision by a customer to request a low noise guarantee or a noise guarantee as a maximum value vs. an average value.

Section II – Consideration of Near-Field Noise Contribution in Acoustic Design

Addresses: Questions by Partners and Customers regarding noise contribution issues.

We hope that you find this document informative and helpful during discussions on the subject of Power Plant related noise.

Charles W. Powers
GE Energy

Section I

Power Generation Equipment and Other Factors Concerning the Protection of Power Plant Employees against Noise

Introduction

Noise has become an increasingly important subject in the matter of workers' protection and health. Hearing impairment has been identified as one of the major health issues for Power Plant Employees and Owners. Studies indicate that exposure-related hearing loss is caused by exposure to high noise levels over extended periods of time. Hearing loss is therefore associated with both the level and duration of the noise to which an individual is exposed. Exposure-related hearing loss can also be caused by exposure to extremely loud impulse type noises.

To address this concern, Health and Safety Agencies in many parts of the world have developed noise exposure limits for Power Plant Employees.Typically these Agencies have established lower (trigger) levels and upper average exposure limits, along with peak noise limitations. The lower level typically "triggers" specific actions, which must be taken by the Power Plant Owner. The lower (trigger) and upper exposure limit values are usually the average level of noise a worker is exposed to for an eight (8) hour time period. For the protection of Power Plant Employees, Power Plant Owners must take specific actions when the Employees' exposure to noise has reached these levels. *It should be noted that these regulations do not specify a limit on the noise level of equipment. The regulation is on the level of noise a Power Plant Employee may be exposed to, over a specific period of time.*

In response to these requirements, Power Plant Owners are specifying lower limits for noise levels from the power generation equipment they are purchasing. In many cases, the noise levels that are specified by the Power Plant Owners are at or below the lower threshold for action established by the Health and Safety Agency, and/or are specified as maximum allowable levels. While ensuring that the respective limits will be met, these noise level requirements are typically more restrictive than required to comply with the specified exposure limits, and impose considerable unnecessary costs to the Power Plant Owners.

The purpose of this paper is to discuss the intent of these requirements and explore the various methods that can be used to ensure the health and safety of the Employee, while controlling the cost impact on the Power Plant Owners.

Before discussion of this topic begins, it must be clearly understood by all parties, that responsibility for compliance with these Health and Safety requirements rests with the Power Plant Owner, and to a lesser extent, with the Power Plant Employee.

Discussion

Noise exposure limits typically include two noise indicators: the daily personal exposure $L_{ex,d}$ and the maximum unweighted instantaneous sound pressure p_{peak} (C weighted).

The following formulas can be used to calculate an Employee's Exposure for an 8-hour period:

$$L_{EX,8h} = L_{Aeq,Te} + 10 \log_{10} \frac{T_e}{T_0}$$

where

$$L_{Aeq,Te} = 10 \log_{10} \left\{ \frac{1}{T_e} \int_0^{T_e} \left[\frac{P_A{}^2}{P_0{}^2} \right] dt \right\}$$

Te = daily duration of a worker's personal exposure to noise (hr)

T_0 = 8hr

p_0 = 20μPa

P_A = "A"-weighted instantaneous sound pressure in pascals (Pa) to which a person is exposed.

Calculation of a ***daily 8-hour average*** exposure would typically be used for employees who are exposed to a continuous / constant noise level (such as Operators who are in essentially the same location throughout their shift).

However;

In many cases, for employees who are involved in activities where daily noise exposure varies markedly from one working day to the next, Power Plant Owners may, for the purpose of applying the exposure limit values, ***use the weekly noise exposure level in place of the daily noise exposure leve***l to assess the levels of noise to which workers are exposed, on condition that:

a) The weekly noise exposure level, as shown by adequate monitoring, does not exceed an established exposure limit value

- and -

b) Appropriate measures are taken in order to reduce the risk associated with these activities to a minimum

This would typically apply to employees such as Inspectors and Maintenance Personnel, whose responsibilities would normally require them to be in several different areas of the Power Plant in any given time frame.

Local Codes and Regulations vary, and should be reviewed for specific requirements. As an example, the following is a summary of the United States Occupational Safety and Health Administration (OSHA) regulation:

The United States Occupational Safety and Health Administration (OSHA) requires that worker noise exposure not exceed 90 dBA based on an 8 hour time weighted average. If worker noise exposure exceeds this regulatory limit, personal hearing protection is mandatory and exposure must not exceed this level when considering the attenuation provided by the hearing protection. If a worker's exposure exceeds a trigger level of 85 dBA, again based on an 8 hour time weighted average, the employer must implement a hearing conservation program. In addition, exposure to impulsive or impact noise shall not exceed 140 dB peak sound pressure level.

The following Table is copied from the OSHA regulation. As indicated in *Table G-16*, the OSHA regulations do not mandate specific noise limits within a facility. Rather the regulations specify allowable duration of exposure to sound levels.

Table G-16 – Permissible Noise Exposures

Duration per Day, Hours	Sound Level dBA
8	90
6	92
4	95
3	97
2	100
1 1/2	102
1	105
1/2	110
1/4 or less	115

Footnote.[1] When the daily noise exposure is composed of two or more periods of noise exposure of different levels, their combined effect should be considered, rather than the individual effect of each. If the sum of the following fractions: $C_1/T_1 + C_2/T_2 \ldots + C_n/T_n$ exceeds unity, then, the mixed exposure should be considered to exceed the limit value. C_n indicates the total time of exposure at a specified noise level, and T_n indicates the total time of exposure permitted at that level. Exposure to impulsive or impact noise should not exceed 140 dB peak sound pressure level.

Considerations:

The two major factors in limiting exposure are the noise level an individual is exposed to, and the amount of time an individual is exposed to a particular level of noise. Each of these may be controlled in various ways.

Control of the exposure noise level may be achieved by:

1a) Reduction at the source
1b) Use of enclosures, barrier walls, etc.
1c) Use of hearing protection
1d) Designating high noise areas as restricted areas

Control of exposure time may be achieved by:

2a) Monitoring Programs
2b) Varying shifts
2c) Varying job assignments
2d) Avoiding high noise areas

Specification of a maximum allowable level of noise from the source (equipment) takes only two of these control factors into consideration *[1a) Reduction at the source, and 1b) Use of enclosures, barrier walls, etc.]*. These could be the most expensive methods of limiting exposure to noise. The most cost effective approach is a comprehensive noise program, incorporating a combination of the factors listed above.

As indicated earlier, these regulations typically require the implementation of an effective hearing conservation program if exposure levels exceed the lower (trigger) level. Again, to ensure the varying worker exposure levels do not exceed the trigger level, the hearing conservation program is typically initiated if any area in the plant exceeds that level. Within a power facility there will be instances in which a worker is exposed to sound levels in excess of the trigger level. Even if every location in the plant is controlled to a level below the trigger level, there will be times when workers will need to enter the noise control enclosures during facility operation. The workers will be exposed to high noise levels during those periods and hearing protection will need to be worn at those times. The potential for a worker to be exposed to levels above the trigger level will always exist in a power facility. As such, a hearing conservation program will always be necessary and can not be avoided with increased noise mitigation.

Other factors having an impact on average exposure over an 8-hour period include:

a) Power Plant Employee Exposure limits are typically for an average exposure. For example, an individual could be exposed to levels of 82 dBA for 2 hours, 80 dBA for 4 hours and 76 dBA for 2 hours, and still fall under a lower threshold of 80 dBA average for 8 hours.

b) Varying noise levels around complex equipment. Complex equipment designed to meet a specific dBA average noise level will typically have many areas well below that level.

c) Access to areas, which are traditionally "High Noise." Such access is frequently not permitted during typical Power Plant operation activities for safety reasons.

d) Many areas in a typical plant and on the "turbine island" (including "high noise" areas) require only occasional access, and may be designated as requiring hearing protection for entrance.

e) In most cases, when a maximum exposure limit value has been specified (87dBA, for example), it will take the attenuation provided by individual hearing protection into account when calculating the Employee's exposure. For example; if the Employee is exposed to a noise level of 90dBA for an eight-hour shift, and is wearing hearing protection that provides 10dBA of attenuation, his/her exposure equals 80dBA for the eight-hour shift, and is well below the exposure limit.

Exposure Thresholds and Required Actions:

The list below shows the relationship between typical exposure thresholds, and the actions that must be taken by the Power Plant Owners at each threshold level.

This comparison of typical required actions at the various Exposure Limits reveals that the differences between actions, which must be taken at the lowest value vs. the highest value, are comparatively small as long as the highest Exposure Limit is not exceeded.

A. When Exposure Action Values are at the lower threshold and above, **Information** and **Training** *are required*.

B. When Exposure Action Values range between the lower and upper thresholds, **Hearing Protection** and **Testing** must be *made available*.

C. When the upper Exposure Action Value is reached, use of **Hearing Protection** is *required*.

Note: It is important to note that in many cases, **Information and Training** is the only *Mandated* action, until the upper Exposure Action Value has been reached.

Average vs. Maximum

When taking the following enumerated factors into consideration, it is logical to conclude that *equipment generating an acceptable average noise level* will enable the Power Plant Owners to ensure that an Employee's exposure does not exceed a permitted *average* 8-hour exposure level:

- In most cases, an employee would not be in one position, within 1 meter of the operating equipment, for an entire 8-hour shift.
- Noise levels around complex equipment vary with location.
- Areas, which are traditionally "High Noise", are frequently access limited.
- Many areas in a typical plant and on the Turbine Island (including "high noise" areas) require only occasional access.

In contrast, a "maximum" noise level specification requires that no noise level, measured in accordance with accepted procedures, may be greater than the level guaranteed. This would include areas that may be inaccessible, and areas that are infrequently occupied.

In view of these facts, there is no significant advantage to be gained from a "maximum" specification.

In addition to the above, a recent internal market study has shown that 80% of the requested equipment guarantees in contracts for Power Plants in European Union countries (where noise regulations are currently most stringent) were average values versus 20% maximum guarantees. This indicates that many Power Plant Owners have reached similar conclusions, and intend to consider all factors when determining the equipment noise levels they will require.

Conclusion

When reviewing Health and Safety requirements regarding noise exposure, there is no specification of the permitted noise levels of power generation equipment. The intent is to limit the exposure of the Employee to noise. As discussed herein, there are two major factors that have a bearing on an individual's average exposure to noise over an 8-hour period (the noise level(s) the Employee is exposed to, and the duration of the exposure). In addition, there are several criteria that influence each of the major factors. The noise level of the power generation equipment is only one of these.

Consideration should also be given to the possibility that mitigation measures required to achieve very low, or maximum, noise levels may have a negative impact on the ability to access certain areas for maintenance purposes, and in some cases may have a negative impact on the performance of the equipment.

Recommendation

An optimum approach to compliance with noise exposure requirements should include a combination of equipment generating an average noise level, and a comprehensive noise exposure management program. This will allow the Power Plant Owner to ensure the health and safety of their employees, while minimizing cost and possible negative impact on maintainability and performance of the equipment.

It is recommended that a thorough analysis be conducted, including all of the factors, variables and considerations presented in this paper, when determining the power generation equipment noise levels that Power Plant Owners will require.

Section II

Considerations of Near-Field Noise Contribution in Acoustic Design

Contribution Considerations

The noise level at any location within a power plant is the combined effect of noise radiated by all sources. Therefore, the noise from each individual source must be less than the overall plant requirement.

In addition, the containment of the sound energy within a building results in a reverberant buildup of noise. The noise reflected from the interior building walls and other surfaces causes an increase in the noise level.

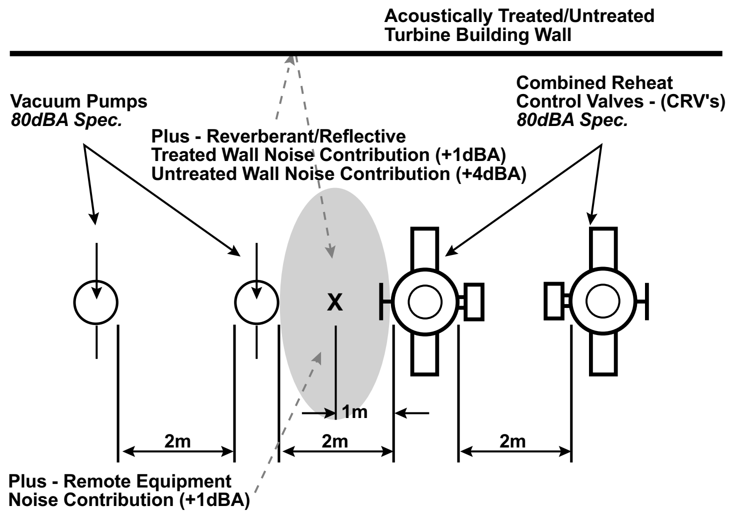
Examples

For example, in order for the entire power plant to satisfy a client-required noise guarantee of 85 dBA, it is necessary for each piece of equipment (including all of GE scope of supply equipment as well as the equipment supplied by others) that may be influenced by one or more of these factors, to radiate less than 85 dBA.

As an example, if the vacuum pump and the combustion turbine are located 2 meters apart, and if the vacuum pump radiates 80 dBA at 1 meter and the combustion turbine radiates 80 dBA at 1 meter, the resulting sound level from the two pieces of equipment is 83 dBA at a location 1 meter from both pieces of equipment (80 dBA + 80 dBA = 83 dBA). In addition, there will be noise from other equipment within the area. A 1 dBA allowance is included to account for the contribution from this other equipment. To account for the reverberant buildup effect of noise within a building with interior walls that are properly treated for acoustics, an additional 1 dBA allowance is also included. Therefore, these two pieces of equipment must be designed to a level of 80 dBA or less for the measured sound levels to meet the client's requirement of 85 dBA.

Note: If the Turbine Building interior walls are untreated, the allowance for reverberant effect should be 4 dBA – 7 dBA, depending on specific conditions.

To minimize the impact of achieving these stringent noise requirements, no design margin is typically included in these design values. The values specified are anticipated to achieve the required sound levels with no additional design margin. The GE-supplied equipment will be designed to the same stringent sound level requirements as the equipment supplied by others. ***See Figure 1 for examples and a representative diagram.***



Shaded Area is 3dBA greater than noise level of 2 equal contributors. If contributor noise level is not equal, use table below. Contribution from Remote Equipment and Reflection/ Reverberation must also be added.

Delta	Add (dBA) to Higher Level
0	3
1	3
2	2
3	2
4	1
5	1
6	1
7	1
8	1
9	1
10+	0

Excerpt from: ISO 11690-2 (1996) Annex B: "Placing 2 equally loud noise sources together increases the total noise level by 3dB."

Figure 1. Near Field Noise Contribution Example

Example A: (Figure 1)

X - Noise Measurement (Designed As Specified to meet 85dBA Guarantee):

Vacuum Pump Noise Emissions	= 80 dBA at 1 meter
CRV Noise Emissions	= 80 dBA at 1 meter
Resulting Sound Level	= 83 dBA at 1 meter
Allowance for Other Equipment	= 1 dBA
Allowance for Reverberation Buildup	= 1 dBA (Treated Building) 4dBA (Untreated)
Measured Sound Level	= 85 dBA (Treated Building) 88dBA (Untreated)

Example B: (Figure 1)

X - Noise Measurement (Designed At Guarantee Level of 85dBA):

Vacuum Pump Noise Emissions	= 85 dBA at 1 meter
CRV Noise Emissions	= 85 dBA at 1 meter
Resulting Sound Level	= 88 dBA at 1 meter
Allowance for Other Equipment	= 1 dBA
Allowance for Reverberation Buildup	= 1 dBA(Treated Building) 4dBA (Untreated)
Measured Sound Level	= 90 dBA(Treated Building) 93dBA (Untreated)

DOES NOT MEET GUARANTEE LEVEL

Example C: (Figure 1)

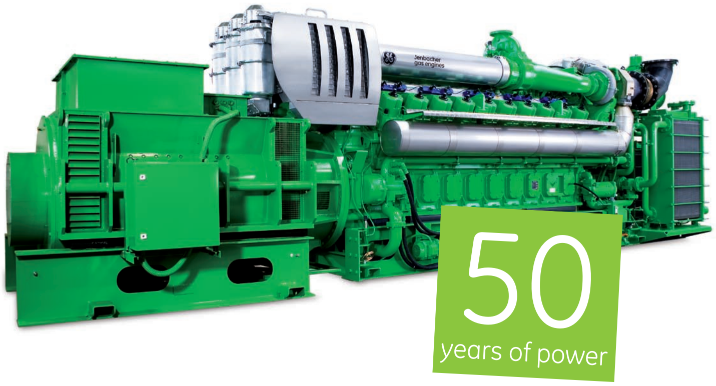
X - Noise Measurement (With Unequal Contributors, 1 at Spec., 1 at Guarantee):

CRV Noise Emissions	= 80 dBA at 1 meter
Vacuum Pump Noise Emissions	= 85 dBA at 1 meter
Resulting Sound Level	= 86 dBA at 1 meter
Allowance for Other Equipment	= 1 dBA
Allowance for Reverberation Buildup	= 1 dBA(Treated Building) 4dBA (Untreated)
Measured Sound Level	= 88 dBA(Treated Building) 91dBA (Untreated)

DOES NOT MEET GUARANTEE LEVEL

GE
Energy

Jenbacher type 6

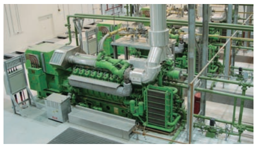
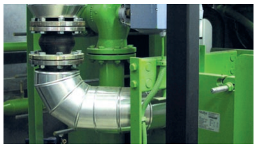


50
years of power
Jenbacher gas engines

cutting-edge technology

Continuously refined based on our extensive experience, the Jenbacher type 6 engines are reliable, advanced products serving the 1.8 to 3 MW power range. Its 1,500 rpm engine speed results in a high power density and low installation costs. The type 6 pre-combustion chamber achieves maximum efficiency with low emissions. Proven design and optimized components enable a service life of 60,000 operating hours before the first major overhaul.

reference installations

model, plant	key technical data	description	
J612 GS **Beretta, industry; Gardone, Italy**	Fuel .... Natural gas Engine type .... 1 x JMS 612 GS-N.L Electrical output .... 1,457 kW Thermal output .... 5,241 MBTU/hr Commissioning .... December 1998	The generated electricity covers the entire electricity requirement of the Beretta factory, while the heat is used for the production process. By using our cogeneration system, Beretta was able to reduce the energy supply costs for the factory by 30%.	
J616 GS **Mussafah Industrial City, residential area; Abu Dhabi, UAE**	Fuel .... Natural gas Engine type .... 3 x JGS 616 GS-N.L Electrical output .... 6,018 kW Commissioning .... June 2003	Three Jenbacher generator sets supply power generation for continuous operation of compressor chillers to provide chilled water for cooling to a residential area that incorporates apartments, shopping centers, mosques, a police station, and a cinema complex.	
J616 GS **Van der Arend Roses; Maasland, The Netherlands**	Fuel .... Natural gas Engine type .... 2 x JMS 616 GS-N.LC Electrical output .... 4,376 kW Thermal output .... 17,950 MBTU/hr Commissioning .... February and December 2003	The Jenbacher cogeneration systems provide power for artificial lighting, heat and CO_2 to increase the greenhouse rose production capabilities. The CO_2 produced from the exhaust gas of the engines is used for fertilization in the greenhouses.	
J620 GS **Biomass power plant; Güssing, Austria**	Fuel .... Wood gas Engine type .... 1 x JMS 620 GS-S.L Electrical output .... 1,964 kW Thermal output .... 8,504 MBTU/hr (district heating 158°F/194°F) Commissioning .... April 2002	The wood gas produced and cleaned in a fluidized bed/steam reactor is converted into heat and power in the Jenbacher cogeneration plant and forms an important component in an innovative project aimed at meeting 100% of the region's energy needs from renewable sources.	

GE imagination at work

technical features

feature	description	advantages
Four-valve cylinder head	Centrally located purged pre-combustion chamber, developed using advanced calculation and simulation methods (CFD)	- Minimized charge-exchange losses - Highly efficient and stable combustion - Optimal ignition conditions
Heat recovery	The oil heat exchanger can be specified as a two-stage plate heat exchanger	- Maximum thermal efficiency, even at high and fluctuating return temperatures
Air/fuel mixture charging	Fuel gas and combustion air are mixed at low pressure before entering the turbocharger	- Main gas supply with low gas pressure - Mixture homogenized in the turbocharger
Pre-combustion chamber	The ignition energy of the spark plug is amplified in the pre-combustion chamber	- Highest efficiency - Lowest NOx emission values - Stable and reliable combustion
Special gas mixer	Specific version for special gases with low calorific values	- Trouble-free operation with special gases with large calorific value differences

technical data

Configuration	V 60°
Bore (inch)	7.48
Stroke (inch)	8.66
Displacement/cylinder (cu.in)	380.7
Speed (rpm)	1,500 with gearbox (60 Hz)
Mean piston speed (in/s)	433
Scope of supply	Generator set, cogeneration system
Applicable gas types	Natural gas, flare gas, biogas, landfill gas, sewage gas. Special gases (e.g., coal mine gas, coke gas, wood gas, pyrolysis gas)

Engine type	J612 GS	J616 GS	J620 GS
No. of cylinders	12	16	20
Total displacement (cu.in)	4,568	6,090	7,613

Dimensions l x w x h (inch)

Generator set	J612 GS	360 x 90 x 110
	J616 GS	400 x 90 x 110
	J620 GS	420 x 90 x 110
Cogeneration system	J612 GS	360 x 90 x 110
	J616 GS	400 x 90 x 110
	J620 GS	420 x 90 x 110

Weights empty (lbs)

	J612 GS	J616 GS	J620 GS
Generator set	41,240	53,200	66,180
Cogeneration system	42,340	54,300	67,500

outputs and efficiencies

Natural gas 1,500 rpm | 60 Hz

NOx <	Type	Pel (kW)[1]	ηel (%)	Pth (MBTU/hr)[2]	ηth (%)	ηtot (%)
1.1 g/bhp.hr	612	1,801	42.9	6,189	43.2	86.1
	616	2,390	42.6	8,295	43.4	86.1
	620	2,994	42.3	10,447	43.3	85.6
0.6 g/bhp.hr	612	1,801	42.2	6,365	43.7	85.9
	616	2,390	42.2	8,368	43.3	85.4
	620	2,994	41.6	10,618	43.3	84.9

Biogas 1,500 rpm | 60 Hz

NOx <	Type	Pel (kW)[1]	ηel (%)	Pth (MBTU/hr)[2]	ηth (%)	ηtot (%)
1.1 g/bhp.hr	612	1,432	39.1	5,702	45.6	84.7
	616	1,914	39.2	7,574	45.4	84.6
	620	2,388	39.1	9,481	45.5	84.6
0.6 g/bhp.hr	612	1,432	38.5	5,692	44.8	83.3
	616	1,914	38.6	7,567	44.7	83.3
	620	2,388	38.5	9,471	44.7	83.2

1) Electrical output based on ISO standard output and standard reference conditions according to ISO 3046/I-1991 and p.f. = 1.0 according to VDE 0530 REM with respective tolerance; minimum methane number 80 for natural gas

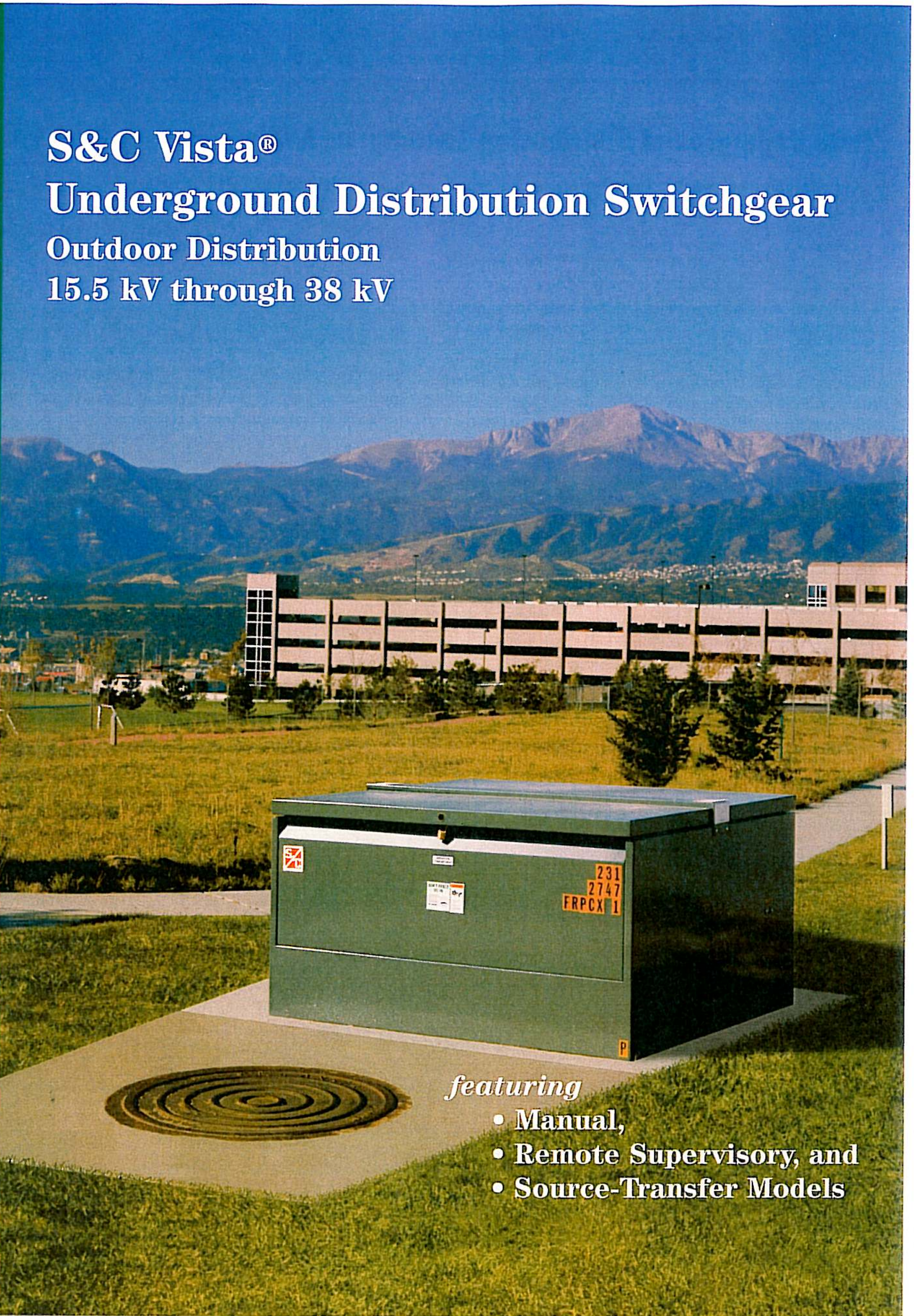
2) Total heat output with a tolerance of +/- 8%, exhaust gas outlet temperature 248°F, for biogas exhaust gas outlet temperature 356°F

All data according to full load and subject to technical development and modification.

GEA-13691US-R2

GE Energy   Jenbacher gas engines North America   Houston, TX 77032   T +1 832 2955600   F +1 281 4429994   jenbacher.us@ge.com   www.gejenbacher.com

S&C Vista®
Underground Distribution Switchgear
Outdoor Distribution
15.5 kV through 38 kV



featuring
- Manual,
- Remote Supervisory, and
- Source-Transfer Models

S&C ELECTRIC COMPANY
Specialists in Electric Power Switching and Protection

Descriptive Bulletin 680-30
June 1, 2004
Supersedes Descriptive Bulletin 680-30 dated 9-10-01

Vista Underground Distribution Switchgear Addresses Your Concerns

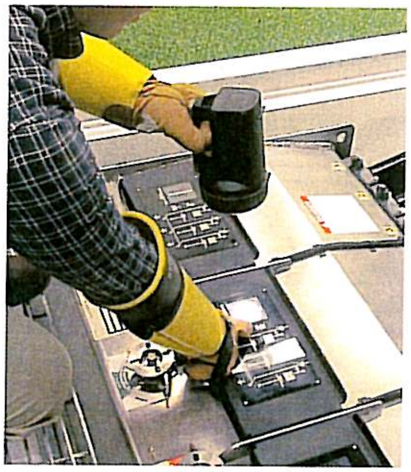
- Are you wasting money and resources on time-consuming, labor-intensive routine operation of your switchgear?
- Has coordinating upstream protective devices with downstream fusing become a headache?
- Are your customers complaining that they don't want obtrusive green boxes on their property?

S&C's Vista Underground Distribution Switchgear is the answer to these and many other underground distribution system problems. S&C worked closely with electric utilities and power users to identify and satisfy needs that were not being met by conventional underground distribution equipment. Vista UDS is an exceptional product that meets all of these needs.

Vista Underground Distribution Switchgear is available in manual, remote supervisory, and source-transfer models. All models feature load-interrupter switches and resettable, vacuum fault interrupters or arc spinners in series with disconnect switches, elbow-connected and enclosed in a submersible, SF_6-insulated, welded steel tank. Vista UDS is available with up to six "ways," in ratings through 38 kV and 25 kA symmetrical short-circuit. Large windows in the tank provide a clear view of the open gap, ground position, and ground bus.

Remote Supervisory Pad-Mounted Style Vista UDS installation.

Large viewing windows let you see open gap and grounded positions on load-interrupter switches and fault interrupters. Trip indicators are easily checked too



Optional voltage indicator with liquid-crystal display. You can check the integrity of the voltage indicator by shining a flashlight on the photocell-powered test circuit, while placing a gloved finger over the test button. See page 8. No flashlight needed in daylight

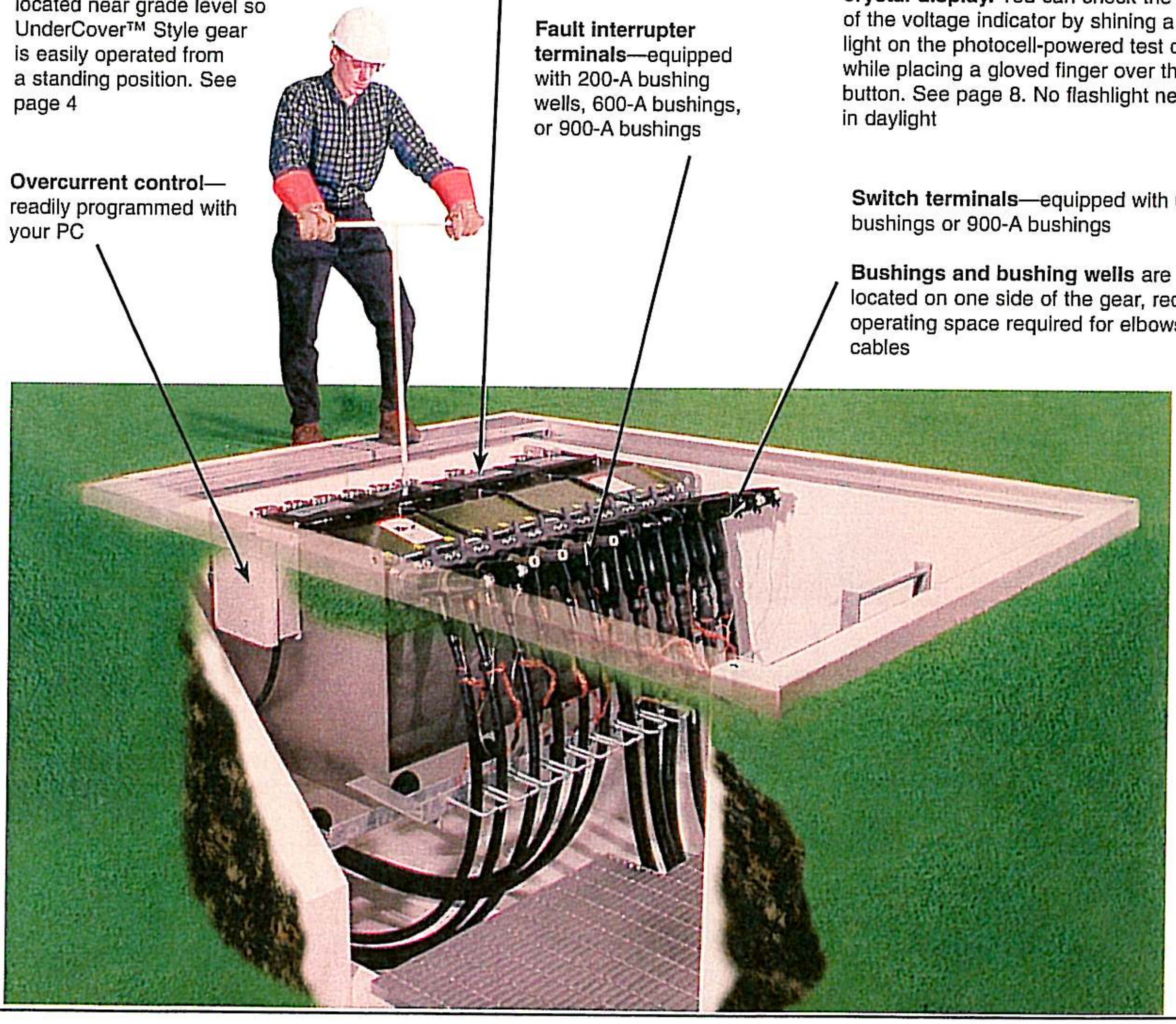
Operating panel is located near grade level so UnderCover™ Style gear is easily operated from a standing position. See page 4

Fault interrupter terminals—equipped with 200-A bushing wells, 600-A bushings, or 900-A bushings

Overcurrent control—readily programmed with your PC

Switch terminals—equipped with 600-A bushings or 900-A bushings

Bushings and bushing wells are located on one side of the gear, reducing operating space required for elbows and cables

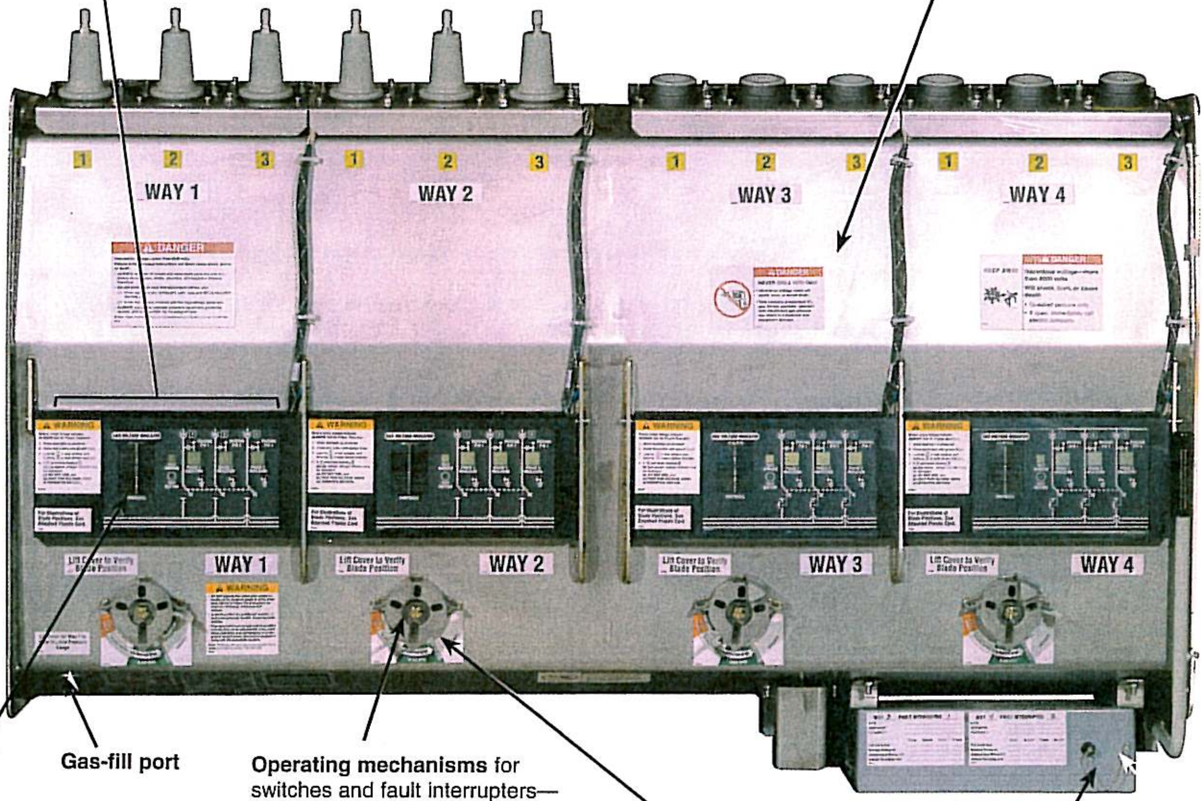


15-kV UnderCover Style Model 422.

The load-interrupter switches provide three-pole live switching of 600-ampere or 900-ampere three-phase circuits. The switches have three positions (closed-open-grounded) and provide a clearly visible gap when open. The 200-ampere, 600-ampere, and 900-ampere fault interrupters offer 40-ms fault clearing, have three-position (closed-open-grounded) disconnects, and are available with either single-pole or three-pole switching. Most models of Vista UDS use in-series vacuum fault interrupters for fault clearing. However, the popular 15-kV, 12.5-kA manual models now feature arc-spinning technology for fault interruption . . . reducing the height of the tank by nearly a foot!

Optional voltage indicator with liquid-crystal display. Includes self-test feature

Compact welded-steel tank protects switching and protection components from the environment. Stainless-steel construction standard in UnderCover Style



Gas-fill port

Operating mechanisms for switches and fault interrupters—padlockable in any position

Pressure gauge—(located under window) temperature and altitude compensated

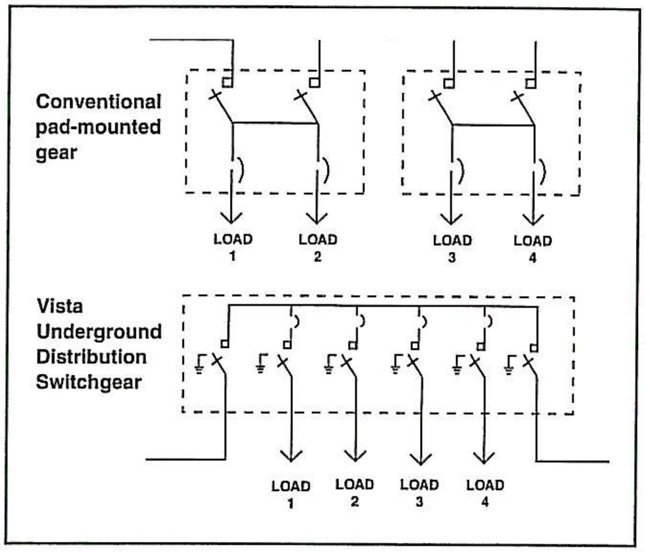
Operation selector prevents inadvertent operation from "closed" position directly to "grounded" position and vice versa

Microprocessor-based overcurrent control housed in watertight enclosure. CTs (not visible) provide power and signal inputs

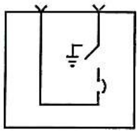
Operating panel of Vista UDS gear. Viewing windows, for confirming open gap and grounded position on load-interrupter switches and fault interrupters, are located under hinged covers of voltage indicators.

Vista UDS is available in up to six "ways." This means it can accommodate any combination of up to six bus taps, load-interrupter switches, or fault interrupters. With conventional pad-mounted gear, for a looped feeder with four taps, two units of gear are necessary. But with Vista UDS, only one six-way unit is needed. Vista UDS simplifies installation and improves aesthetics by reducing the necessary real estate.

The model number indicates the total number of ways, as well as the number of load-interrupter and fault-interrupter ways. For example, Model 321 has "3" ways—"2" load-interrupter switch ways and "1" fault-interrupter way, as shown below.



TYPICAL CONFIGURATIONS OF MANUAL AND REMOTE SUPERVISORY VISTA UDS



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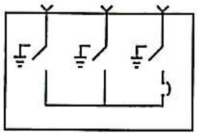
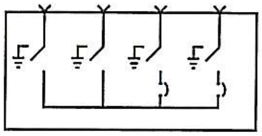
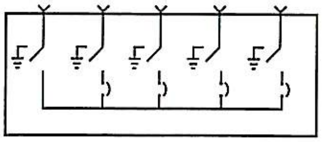


321



422



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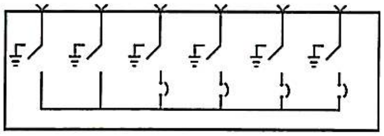

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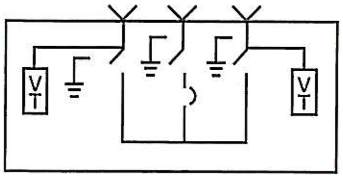
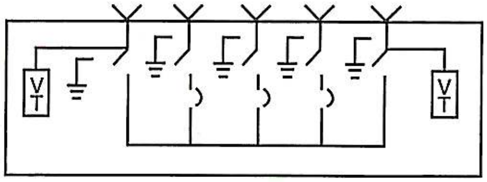
TYPICAL CONFIGURATIONS OF SOURCE-TRANSFER VISTA UDS



321



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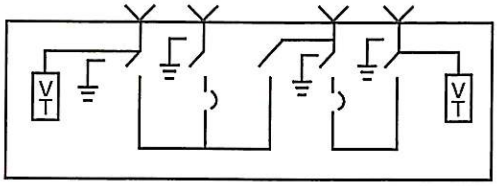


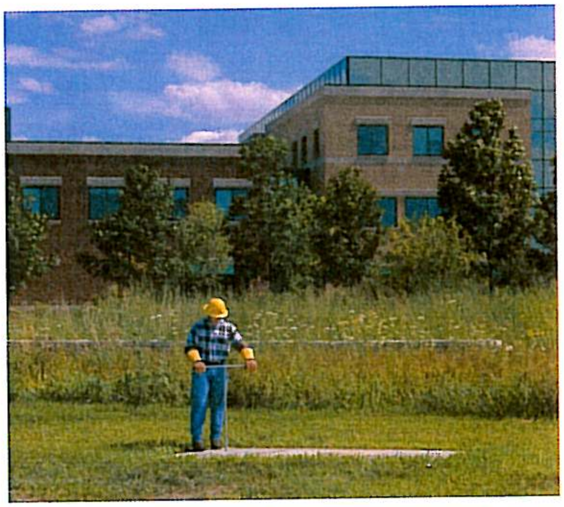
532 (split-bus)

Vista UDS Offers Numerous Unobtrusive Installation Options

One option is the low-profile pad-mounted style. At 15, 25, and even 34.5 kV, pad-mounted Vista UDS is 6 to 14 inches shorter than the average SF_6-insulated gear. And Vista UDS's total real-estate requirement is less than one-third that of a typical SF_6-insulated design. This means that Vista UDS is easier to site and allows more room for landscaping options that further improve aesthetics.

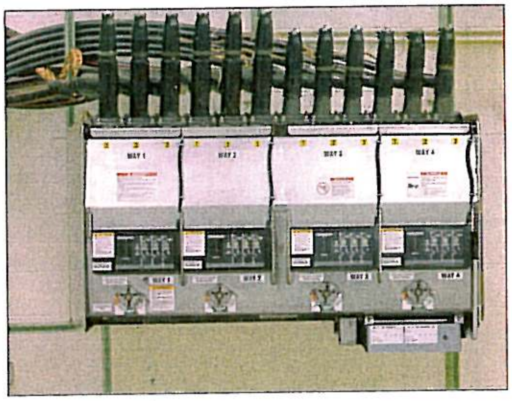
Vista UDS's most innovative installation offering is the UnderCover style. The UnderCover style is ideal for areas with stringent real-estate restrictions or where aesthetics are extremely important. The Vista UDS gear is installed underground, but all operations are easily performed by one operator above ground. UnderCover style installations can also save money by reducing costs associated with trenching and long cable runs.

Vista UDS is also available for floor-mounted or wall-mounted vault installations, and in a man-hole style. With its compact design, rugged construction, and internal visible open point, man-hole style Vista UDS is perfect for applications where installation space is limited.



UnderCover Style.

Pad-Mounted Style.



Vault-Mounted Style—available for floor and wall-mounting.

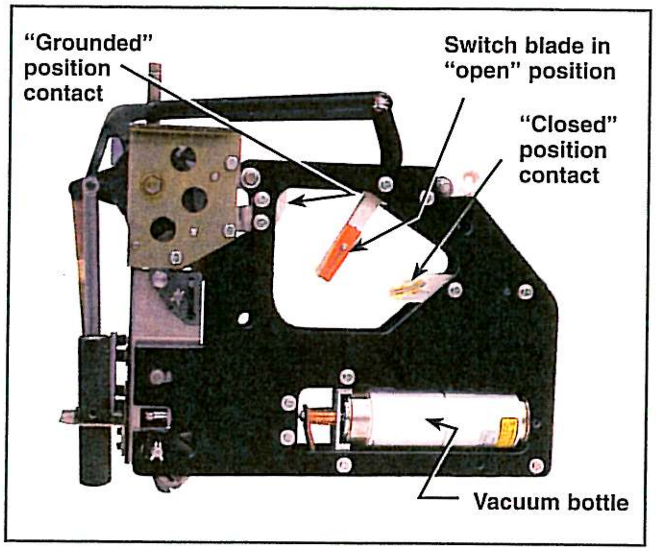
Man-Hole Style.

Vista UDS Operation Is Quicker, Easier, Safer

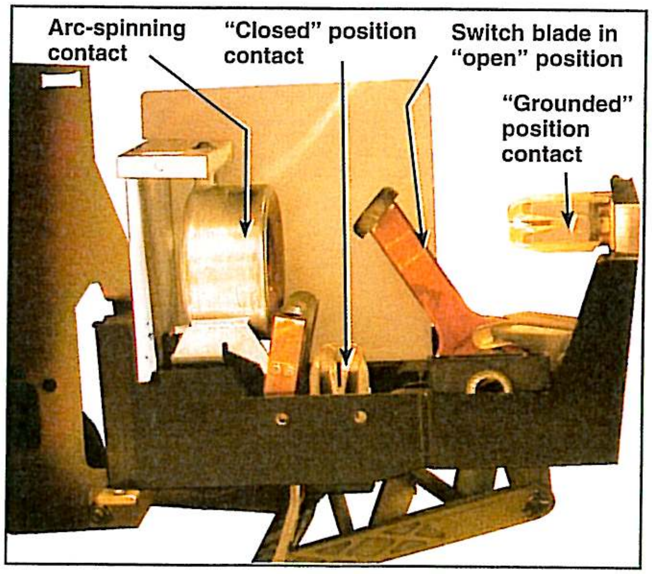
Vista UDS was specifically designed to simplify operating tasks, enhance safety, and minimize the duration of outages. Vista UDS is certified arc-resistant per IEC 298 Appendix AA, for currents up to 12.5 kA symmetrical for 15 cycles (25 kA symmetrical for 15 cycles, for models rated 25 kA short-circuit). In the event of an internal fault, the enclosure will retain its integrity.

Just one person is needed to operate Vista UDS. There's no exposure to medium voltage. The procedure is simple:

1. Rotate the switch operating shaft to the "open" position, then confirm the open gap through the large viewing window. See Figures 1 and 2. With ordinary elbow gear, on the other hand, specially trained operators need to remove the elbows from their bushings using a shotgun clamp stick—a tedious task that must be carefully performed. See Figure 3.



Fault interrupter furnished on all Vista UDS except 15-kV manual models.



Fault interrupter furnished on 15-kV, 12.5-kA manual models.

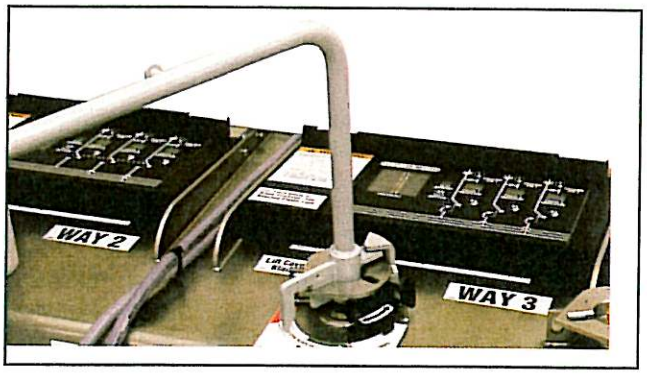


Figure 1. Opening load-interrupter switch (or fault interrupter).

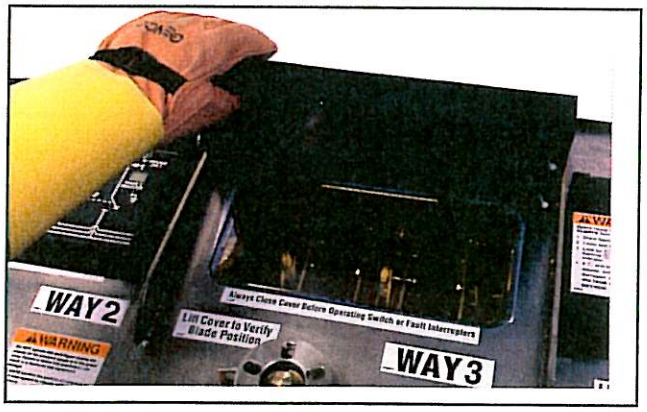


Figure 2. Window cover lifts for viewing switch-blade positions of load-interrupter switch or fault interrupter.

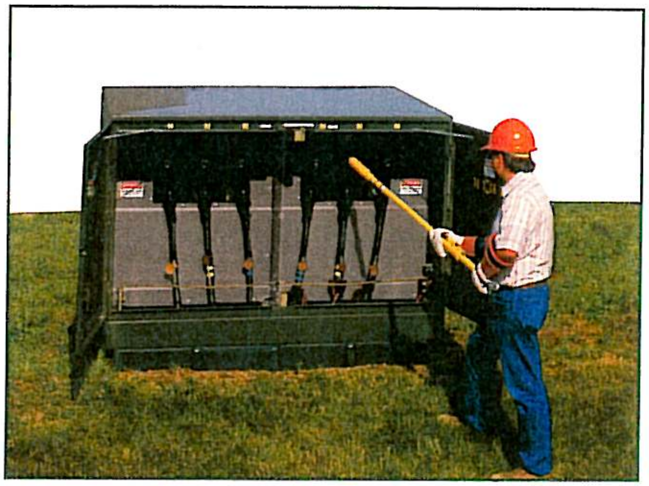


Figure 3. Operation of typical dead-front gear can be awkward and time-consuming.

2. Confirm that the cable is de-energized so it can be safely grounded. With traditional gear, the medium-voltage cables must be tested directly using a clamp-stick-mounted tester. But voltage testing with Vista UDS can be accomplished simply and easily without ever accessing the cables. Simply use the voltage indicators shown in Figure 4. The voltage indicator is even equipped with a self-test function, so you can "test the tester." See Figure 5.
3. Ground the cables. Instead of the awkward task of having to move the elbows to parking stands, along with the grounding bushings or elbows, with Vista UDS you need only rotate the switch operating shaft to the "grounded" position. See Figure 6. Grounding can easily be confirmed by looking through the viewing window.

There are even more benefits: The voltage indicator can be furnished with a low-voltage phasing option. See Figure 7. This feature allows confirmation of proper phasing without ever accessing the cables. Vista UDS allows fault-locating and hi-potting tests to be performed with the cables attached—and the bus energized.

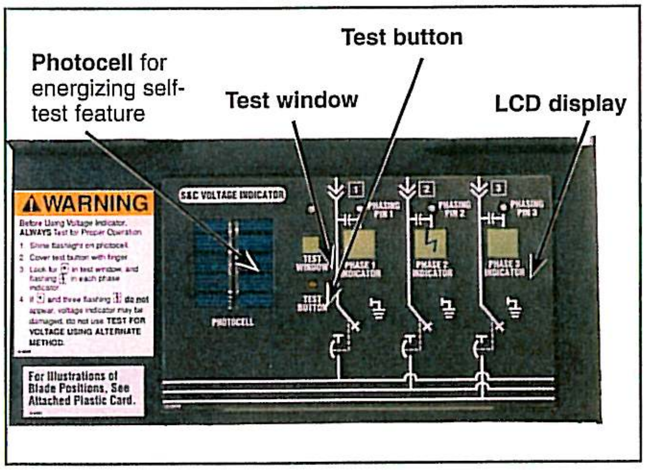


Figure 4. Voltage indicator.

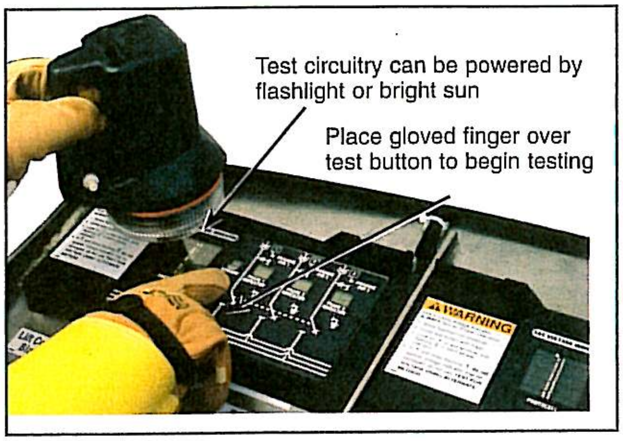


Figure 5. Testing the voltage indicator.

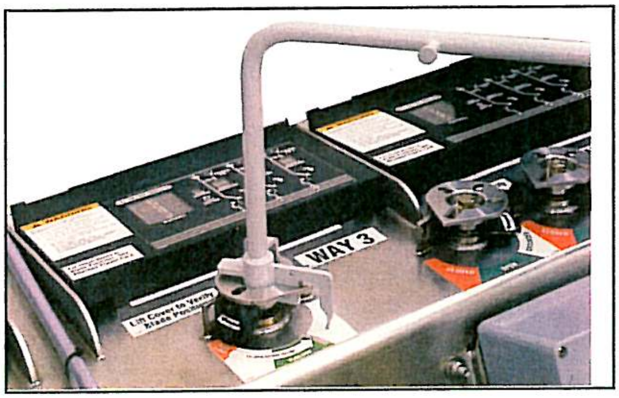


Figure 6. Grounding load-interrupter switch (or fault interrupter).

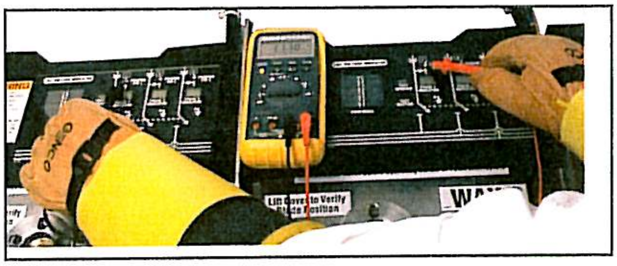
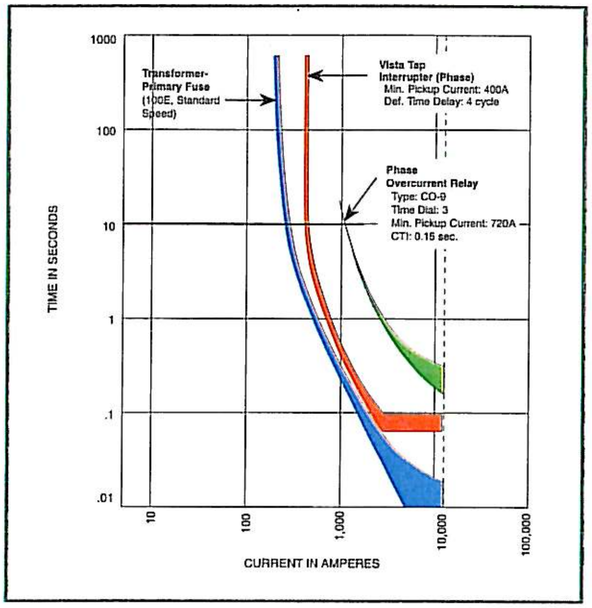


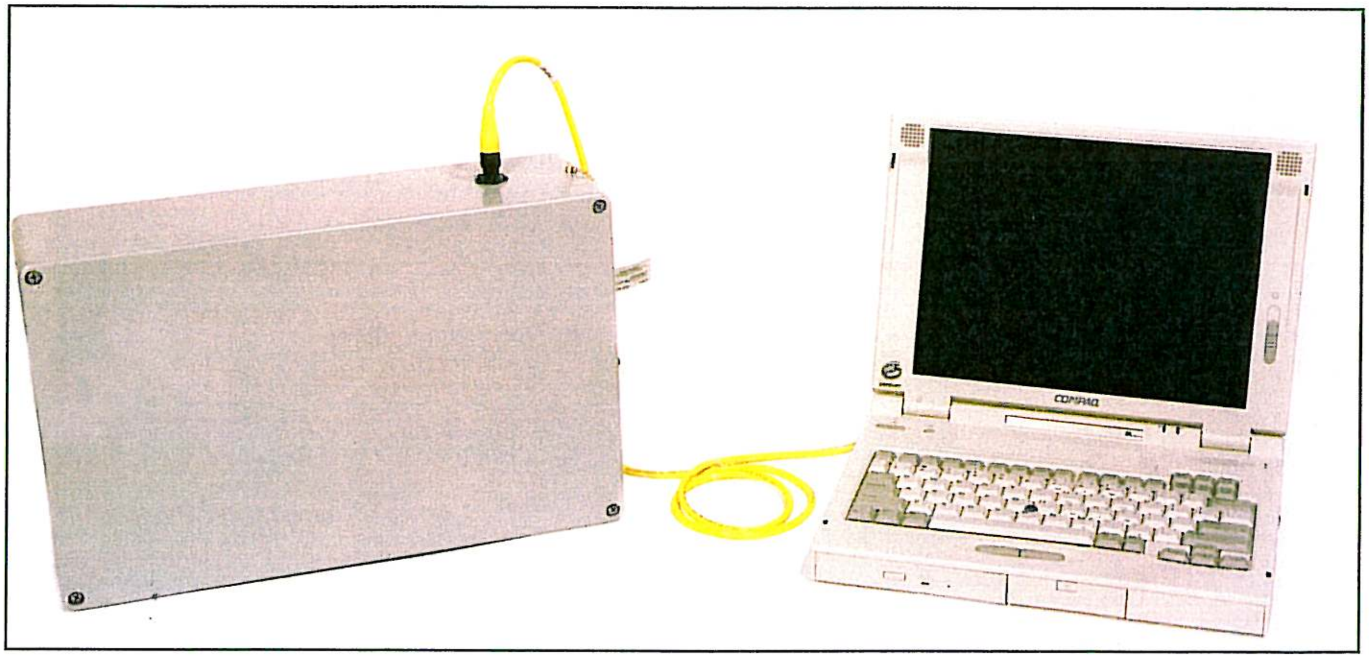
Figure 7. Measuring phase-to-phase voltage—Phase 1 to Phase 1.

Overcurrent Control for Superior Coordination

Vista UDS utilizes a unique microprocessor-based overcurrent control, housed in a watertight enclosure mounted on the gear. The overcurrent control features a variety of TCC (time-current characteristic) curves with selectable instantaneous and definite-time delay attributes, for superior coordination with upstream protective devices and downstream fusing. The parameters for the TCC curves are set using a personal computer connected to the data port of the overcurrent control. There are no knobs or dials, so the settings cannot be inadvertently changed or altered by unauthorized personnel. Integral current transformers provide power and current sensing. There is even an event recorder that captures information on the last twelve operations of each fault interrupter.



Coordinating-speed tap curve with definite-time delay eliminates miscoordination problems frequently encountered with transformer fuses.

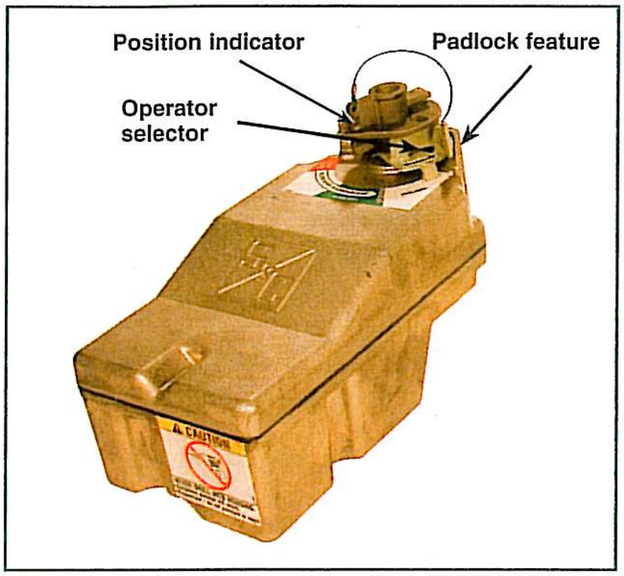


User-supplied personal computer is attached to the overcurrent control for programming the relay in the field.

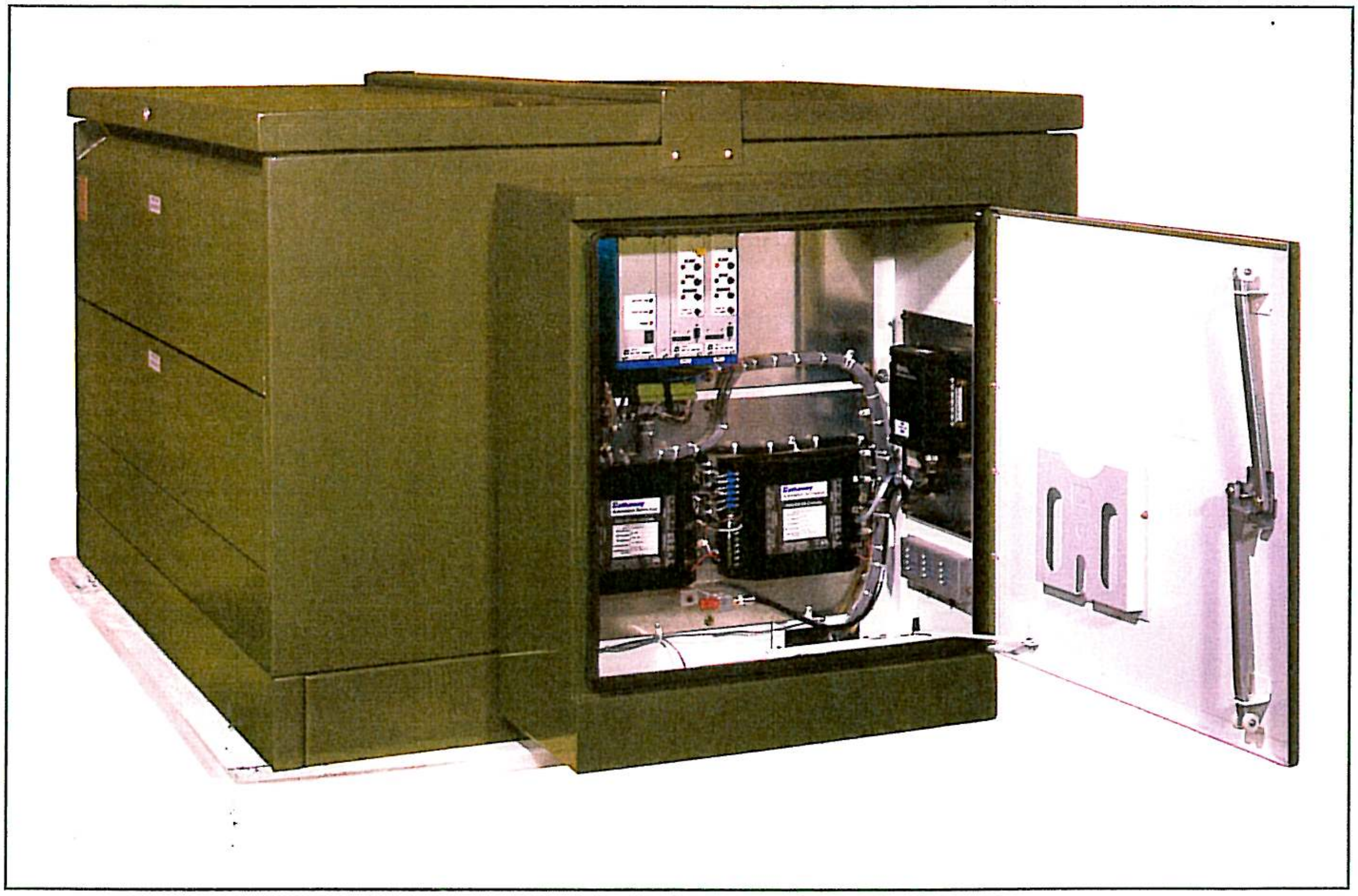
Remote Supervisory Vista UDS

For distribution automation applications, S&C offers Remote Supervisory Vista UDS. Remote Supervisory Vista UDS provides automated switching and fault protection, and can also perform auto-sectionalizing without tripping the main breaker. Automation features are also retrofittable to existing Manual Vista UDS. Motor operators, current and voltage sensors, and low-voltage compartment are easily installed in the field.

Each motor operator includes a control board that provides local push-button and remote operation between the "closed," "open," and "grounded" positions. Up to six control boards can be accommodated within the low-voltage compartment, so any or all load-interrupter switches or fault interrupters can be motor operated. The motor operators may be battery powered or, optionally, self-powered using internal voltage transformers. The low-



Details of motor operator.



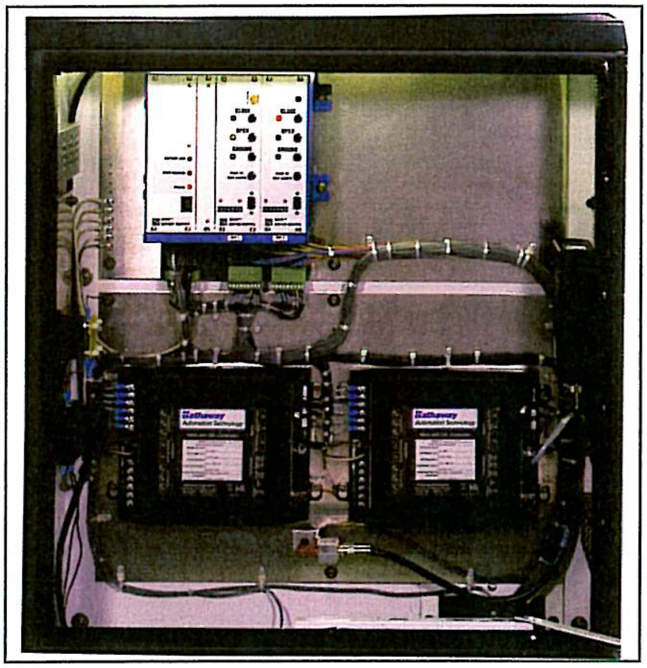
15-kV Remote Supervisory Pad-Mounted Style Model 422.

voltage compartment may also contain a user-specified remote terminal unit and communication device, providing a completely automated switching and protection package. Optional voltage and current sensing round out the Remote Supervisory Vista UDS offering.

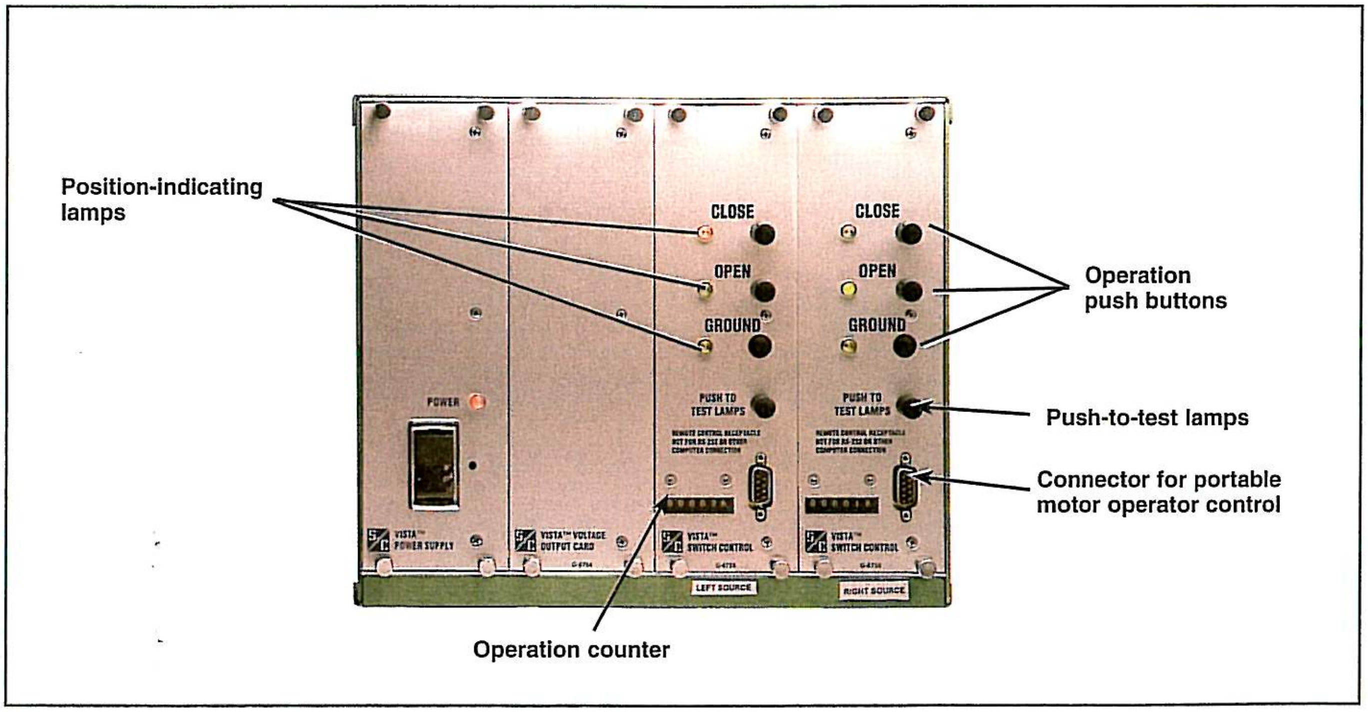
A variety of RTUs have been successfully integrated in Remote Supervisory Vista UDS, including: ACS, Harris DART, Valmet PoleCAT, QEI/Quindar, Hathaway/Systems Northwest, Motorola MOSCAD, and DAQ.

And these transceivers have been integrated: Metricom Utilinet, MDS, Dymec, H&L, and Motorola.

RTUs and communication devices of other manufacture can be accommodated too; contact your nearest S&C Sales Office.

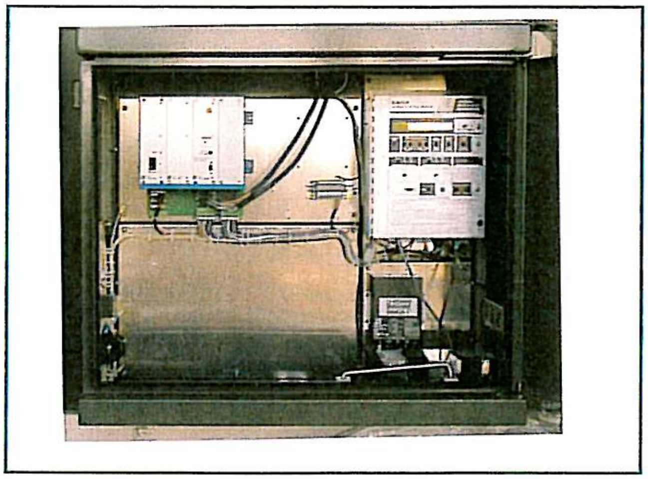


Details of low-voltage compartment of Remote Supervisory Vista UDS Model 422.



Vista motor controls for installation with two motor-operated ways.

When Remote Supervisory Vista UDS is furnished with an EnergyLine 5800 Series Switch Control, it can be a member of an IntelliTEAM®, using EnergyLine's revolutionary peer-to-peer communications. IntelliTEAM software supports automatic sectionalizing and reconfiguration, significantly reducing outage time. IntelliTEAM's peer-to-peer communication network uses distributed intelligence, eliminating the need for, but still fully supporting, a SCADA master station. And, when Remote Supervisory Vista UDS is fitted with an EnergyLine switch control, the gear can be used for automatic source transfer, with remote control and monitoring.

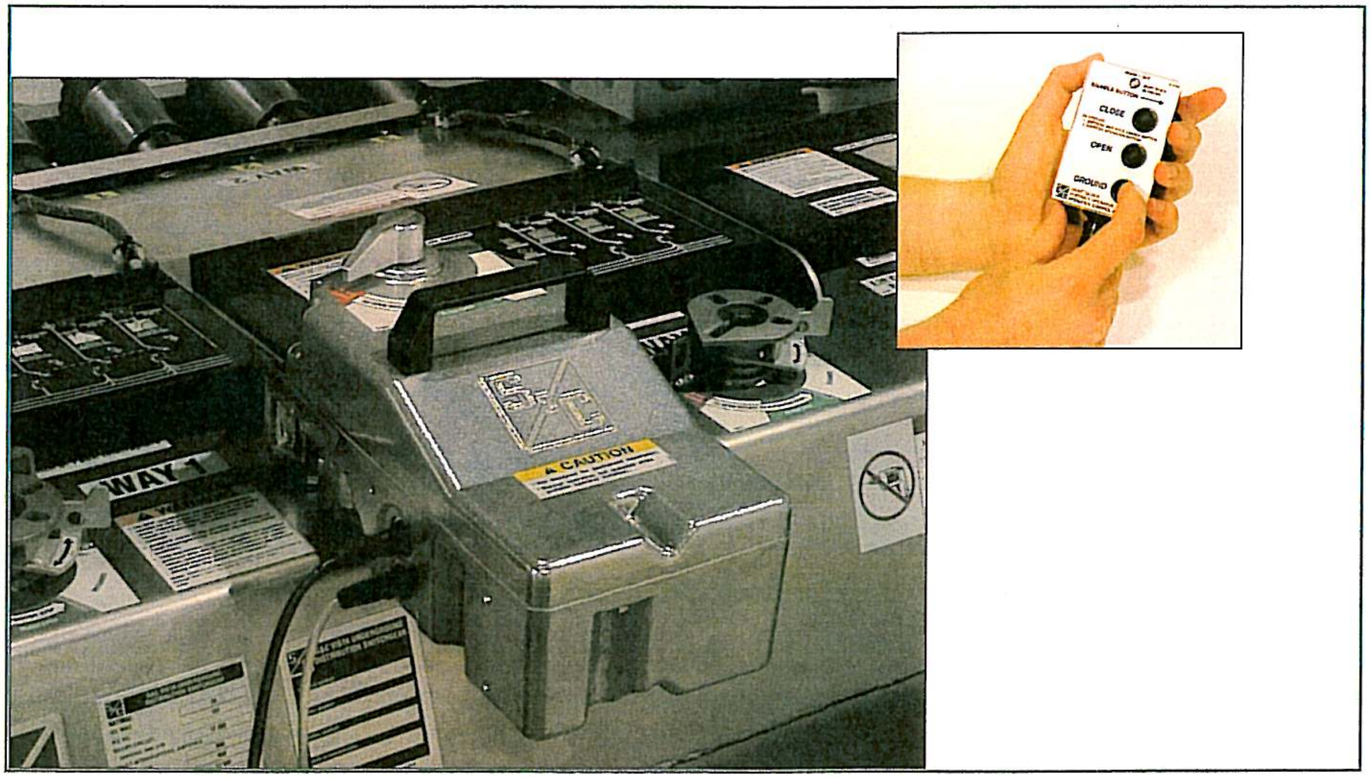

Remote Supervisory Vista UDS with EnergyLine 5800 Series Switch Control.

Remote Supervisory Vista UDS also allows the user to remotely trip the vacuum bottles of any three-phase fault interrupter way using external, user-specified relays. This additional shunt-trip capability permits advanced applications like sensitive earth-ground fault detection, as well as protective relay schemes using high-speed communication for closed-loop and open-loop systems.

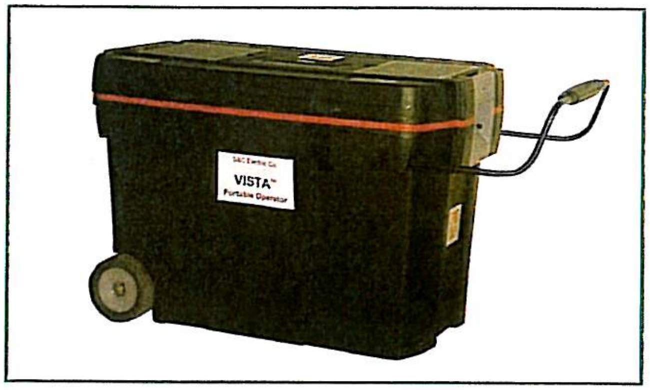
Portable Motor Operator

Local motor operation of Vista UDS gear is also available for users who do not require a complete automation package. The portable motor operator includes cabling and hand-held control, all in an easily portable, durable case.

The operator easily attaches to any load-interrupter switch or single-pole or three-pole fault interrupter. Then simply plug in the power cable and the control cable. The hand-held control features "open," "close," and "ground" push buttons, an "enable" button to prevent inadvertent operation, and a "ready" indicating light.



Vista UDS Portable Motor Operator. Inset shows hand-held control.



Case for Vista UDS Portable Operator.

Source-Transfer Vista UDS

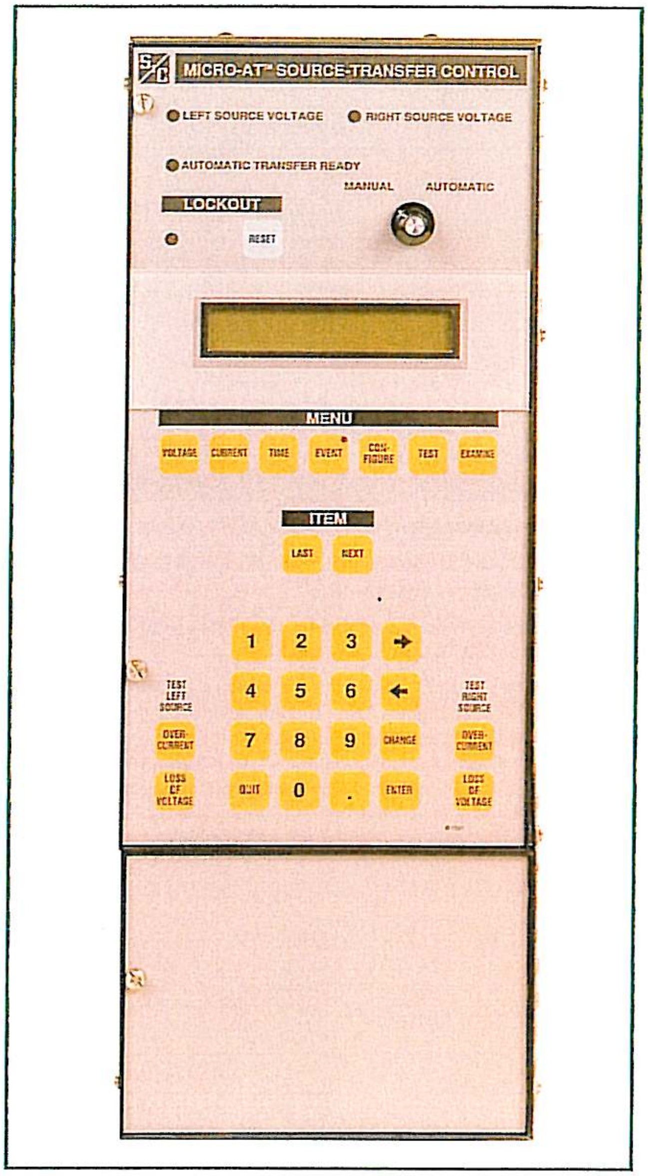
Source-Transfer Vista UDS provides fully automatic primary-selective service for one, two, or three critical load circuits. This package includes all the features of Manual Vista UDS, plus the S&C Micro-AT® Source-Transfer Control, three-phase voltage sensing on source ways, and internal power provided by voltage transformers. It is available in common-bus and split-bus configurations.

The Micro-AT Source Transfer Control, located in the low-voltage compartment, ensures a high degree of critical-load continuity by minimizing interruptions resulting from the loss of one source. Excluding the intentional time delay to coordinate with upstream protective devices and/or transition dwell time, transfer is achieved in 6 seconds maximum.

The Micro-AT Source-Transfer Control utilizes an advanced microprocessor to perform control operations, as directed by settings programmed into the device at the factory and in the field. Such settings, consisting of the control's operating characteristics and voltage-, current-, and time-related operating parameters, are entered into the control by means of a keypad on the front panel.

An unbalance detection feature may be field-programmed in the Micro-AT Source-Transfer Control. This feature protects the loads from any source-side open-phase condition at the same voltage as the Vista Underground Distribution Switchgear. If the voltage unbalance exceeds a preset reference level for a period of time sufficient to confirm that the loss is not transient, an output signal is produced which initiates automatic transfer to the other source.

An overcurrent-lockout feature may be furnished which prevents an automatic transfer operation that would close a source load-interrupter switch into a fault. A light-emitting diode lamp indicates when lockout has occurred. Test keys are provided for simulating an overcurrent condition on each source.



Micro-AT Source-Transfer Control.

Standard Three-Phase Ratings①②③

Applicable Standard	Amperes, RMS									
	Frequency, Hertz	Fault Interrupter			Load-Interrupter Switch				Short-Circuit, Sym.	Main Bus Continuous Current⑦
		Continuous, Load Dropping, and Load Splitting (Parallel or Loop Switching) ④⑤⑥	Fault-Closing, Sym.	Fault Interrupting, Sym.	Continuous, Load Dropping, and Load Splitting (Parallel or Loop Switching) ④⑤⑥	Fault-Closing, Sym.	Momentary, Sym.	1 Sec., Sym.		
IEC	50 or 60	200 or 630	12 500▲	12 500	200 or 630	12 500▲	12 500	12 500	12 500	600
		630	25 500●	25 000	630	25 500●	25 000	25 000	25 000	600
ANSI	50 or 60	200 or 630	12 500▲	12 500	200 or 630	12 500▲	12 500	12 500	12 500	600
		600	25 500●	25 000	600	25 500●	25 000	25 000	25 000	600

① Refer to the nearest S&C Sales Office for other ratings.

② IEC ratings have been assigned in accordance with the applicable portions of IEC 265-1 for a Class A switch.

③ ANSI ratings have been assigned in accordance with the applicable portions of ANSI C37.71, C37.72, and C37.73.

④ Fault interrupters and load-interrupter switches are rated 600 amperes (630 amperes IEC) continuous, load dropping, and loop splitting when furnished with 600-ampere bushings (standard for load-interrupter switches and 25-kA fault interrupters, optional for 12.5-kA fault interrupters). The rating is limited to 200 amperes if 200-ampere bushing wells are used (standard for 12.5-kA fault interrupters, optional for 12.5-kA load-interrupter switches). Models rated 25-kA are only available with 600-ampere bushings.

⑤ Fault interrupters and load-interrupter switches can switch the magnetizing current of transformers associated with the load-dropping rating. In addition, unloaded cable switching ratings are as follows: 10 amperes at 15.5 kV and 20 amperes at 29 kV and 38 kV.

⑥ 900 ampere is also available.

⑦ 1200 ampere is also available.

▲ 32,500-ampere peak ten-time duty-cycle rating.

● 65,000-ampere peak three-time duty-cycle rating. Ten-time duty-cycle fault-clearing rating is 16,000 amperes symmetrical, 41,600 amperes peak.

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
INSIDE SECURE PERIMETER				$74,234,000
HOUSING (7 Pods)				$516,172,000
OUTSIDE SECURE PERIMETER				$36,510,000
PERIMETER CONTROL				$5,733,000
ON-SITE MISCELLANEOUS IMPROVEMENTS				$4,447,000
				$637,096,000
BUILDINGS - FEMALE FACILITY				
INSIDE SECURE PERIMETER				$28,206,000
HOUSING (1 Pod)				$77,760,000
OUTSIDE SECURE PERIMETER				$4,952,000
PERIMETER CONTROL				$2,665,000
ON-SITE MISCELLANEOUS IMPROVEMENTS				$693,000
				$114,276,000
ON-SITE UTILITIES (Male & Female)				$16,019,000
OFF-SITE UTILITIES (Male & Female)				$20,317,000
TOTAL (Construction)				$787,708,000
SOFT COSTS - 25.0%				$196,927,000
TOTAL				$984,635,000

NOTES: Costs Include Contractor General Conditions, Overhead & Profit.
Costs are Based on a Competitive Bid Basis Between 3-4 Bidders.
Costs are Current Costs and Do Not Include Inflation. For Inflation Add 6.0% per Year.
Soft Costs Are: A/E Fees, FF&E, Contingency and Owner Costs.
Costs Do Not Include Land or Finance Costs.

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
INSIDE SECURE PERIMETER				
Central Services	17,100	SF	275.00	$4,703,000
Religious Facilities	37,400	SF	285.00	$10,659,000
Health Care	19,250	SF	350.00	$6,738,000
Reception / Orientation	6,250	SF	285.00	$1,781,000
Plant Maintenance	6,000	SF	250.00	$1,500,000
Laundry	12,100	SF	400.00	$4,840,000
Refuse Station - Docks, Compactors, Recycling	2,000	SF	250.00	$500,000
Culinary - Cook / Chill Facility	45,000	SF	435.00	$19,575,000
Industries	85,000	SF	225.00	$19,125,000
Medical Unit	12,500	SF	385.00	$4,813,000
				$74,234,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
HOUSING (7 Pods)				
Special Pop - Complex One (638 Beds)	206,800	SF	365.00	$75,482,000
Intake Classification:				
(1) 32 Bed Unit, Dorm				
(1) 192 Module, Single Bunked				
(2) 32 Mental Health Units, Dorm				
Mental Health Observation:				
(64) Double Cell Beds				
(32) Single Cell Beds				
(72) Dorm Beds				
Sub-Acute Mental Health:				
(4) 16 Double Bed Units				
Infirmary:				
(54) Infirmary				
Special Pop - Complex One (576 Beds)	194,400	SF	375.00	$72,900,000
(2) 192 Modules, Double Bunked				
(1) 192 Modules, Single Bunked				
Special Pop - Complex Two (384 Beds)	194,400	SF	380.00	$73,872,000
(2) 192 Modules, Single Bunked				
Level Three - Complex One (960 Beds)	214,700	SF	340.00	$72,998,000
(2) 192 Modules, Double Bunked				
(2) 288 Modules, Dorms				
Level Three - Complex Two (864 Beds)	205,800	SF	350.00	$72,030,000
(3) 192 Modules, Double Bunked				
(1) 288 Modules, Dorms				

RUSH VALLEY SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
HOUSING (7 Pods) - Continued				
Level Three - Complex Three (864 Beds) (3) 192 Modules, Double Bunked (1) 288 Modules, Dorms	205,800	SF	350.00	$72,030,000
Levels Four & Five (1,152 Beds) (4) 288 Modules, Dorms	244,000	SF	315.00	$76,860,000
				$516,172,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
OUTSIDE SECURE PERIMETER				
Administration	28,500	SF	215.00	$6,128,000
Enforcement Center	5,000	SF	275.00	$1,375,000
Plant Services				
Vehicle Maintenance	7,000	SF	200.00	$1,400,000
Staff Parking	8,750	SF	6.00	$53,000
Covered Parking	7,000	SF	25.00	$175,000
Motor Pool	29,750	SF	65.00	$1,934,000
Fuel Station	5,000	SF	350.00	$1,750,000
Central Plant	15,000	SF	1,000	$15,000,000
Warehouse				
General Warehouse - Supplies, Canteen, Property & Mail	22,000	SF	125.00	$2,750,000
Outside Covered Storage	2,000	SF	25.00	$50,000
Fenced Storage Yard	10,000	SF	20.00	$200,000
Parking	8,750	SF	6.00	$53,000
Paved Area	30,000	SF	6.00	$180,000
Perimeter Security Towers (6 EA)	2,400	SF	1,800	$4,320,000
Site Traffic Station				
Site Traffic Station	1,250	SF	125.00	$156,000
Parking, Pullouts & Turnarounds	8,500	SF	10.00	$85,000
Lighting	20	EA	4,000	$80,000
Kennels				
Dog Kennels	500	SF	350.00	$175,000
Runs	750	SF	110.00	$83,000
Training Area	2,500	SF	225.00	$563,000
				$36,510,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
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ON-SITE IMPROVEMENTS - MALE FACILITY

PERIMETER CONTROL

SECTION	QUANTITY	UNIT	UNIT COST	COST
Vehicle Sallyport				
Gatehouse	150	SF	325.00	$49,000
Fenced Enclosure	10,000	SF	20.00	$200,000
Perimeter Road	339,000	SF	3.00	$1,017,000
Perimeter Fence - Double	10,300	LF	315.00	$3,245,000
Perimeter Fence Electronics	10,300	LF	100.00	$1,030,000
Perimeter Lighting	16	EA	12,000	$192,000
				$5,733,000

ON-SITE IMPROVEMENTS - MALE FACILITY

ON-SITE MISCELLANEOUS IMPROVEMENTS

SECTION	QUANTITY	UNIT	UNIT COST	COST
Parking				
Staff Parking	175,000	SF	6.00	$1,050,000
Visitor Parking	70,000	SF	6.00	$420,000
Landscaping				
Seed / Landscaping (Minimal)	475,000	SF	0.15	$71,000
Other				
Security Fence	13,000	LF	160.00	$2,080,000
Fenced Yard - Plant Maintenance	5,000	SF	20.00	$100,000
Paved Area - Special Pop, Industries, Etc.	105,000	SF	6.00	$630,000
Site Lighting	24	EA	4,000	$96,000
				$4,447,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - FEMALE FACILITY				
INSIDE SECURE PERIMETER				
Central Services	17,100	SF	275.00	$4,703,000
Religious Facilities	17,300	SF	285.00	$4,931,000
Health Care	10,100	SF	350.00	$3,535,000
Reception / Orientation	3,550	SF	285.00	$1,012,000
Plant Maintenance	6,000	SF	250.00	$1,500,000
Laundry	6,000	SF	400.00	$2,400,000
Refuse Station - Docks, Compactors, Recycling	2,000	SF	250.00	$500,000
Industries	40,000	SF	225.00	$9,000,000
Warehouse	5,000	SF	125.00	$625,000
				$28,206,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

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BUILDINGS - FEMALE FACILITY

SECTION	QUANTITY	UNIT	UNIT COST	COST
HOUSING (1 Pod)				
Special Housing / General Population	167,146	SF	375.00	$62,680,000
Support	52,000	SF	290.00	$15,080,000
				$77,760,000

BUILDINGS - FEMALE FACILITY

SECTION	QUANTITY	UNIT	UNIT COST	COST
OUTSIDE SECURE PERIMETER				
Administration	15,100	SF	215.00	$3,247,000
Site Traffic Station				
Site Traffic Station	1,250	SF	125.00	$156,000
Parking, Pullouts & Turnarounds	8,500	SF	10.00	$85,000
Lighting	6	EA	4,000	$24,000
Perimeter Security Towers (2 EA)	800	SF	1,800	$1,440,000
				$4,952,000

SECTION	QUANTITY	UNIT	UNIT COST	COST
ON-SITE IMPROVEMENTS - FEMALE FACILITY				
PERIMETER CONTROL				
Vehicle Sallyport				
Gatehouse	150	SF	325.00	$49,000
Fenced Enclosure	10,000	SF	20.00	$200,000
Perimeter Road	129,000	SF	3.00	$387,000
Perimeter Fence - Double	4,600	LF	315.00	$1,449,000
Perimeter Fence Electronics	4,600	LF	100.00	$460,000
Perimeter Lighting	10	EA	12,000	$120,000
				$2,665,000

ON-SITE IMPROVEMENTS - FEMALE FACILITY

ON-SITE MISCELLANEOUS IMPROVEMENTS

Parking				
Staff Parking	35,000	SF	6.00	$210,000
Visitor Parking	26,250	SF	6.00	$158,000
Landscaping				
Seed / Landscaping (Minimal)	285,000	SF	0.15	$43,000
Other				
Fenced Yard - Plant Maintenance	5,000	SF	20.00	$100,000
Paved Area - Warehouse, Support & Refuse Station	25,000	SF	6.00	$150,000
Site Lighting	8	EA	4,000	$32,000
				$693,000

RUSH VALLEY SITE - 6,000 BEDS

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ON-SITE UTILITIES (Male & Female)

SECTION	QUANTITY	UNIT	UNIT COST	COST
ON-SITE UTILITIES (Male & Female)				
Sanitary Sewer (Male & Female)				
Sewage Grinder Facility	150	SF	1,000	$150,000
Sanitary Sewer Line w/ Manholes	9,480	LF	90.00	$853,000
Grease Trap	8	EA	30,000	$240,000
Grinder	8	EA	55,000	$440,000
Storm Drain (Male & Female)				
Storm Drainage Line w/ Catch Basins	16,676	LF	110.00	$1,834,000
Water (Male & Female)				
Pump House	175	SF	750.00	$131,000
Water Line w/ Hydrants	19,450	LF	100.00	$1,945,000
Gas (Male & Female)				
Gas Line	12,285	LF	35.00	$430,000
Voice / Data (Male & Female)				
Fiber Optic Line / Racks & Connectivity - Cost Per Engineer	1	LS	146,000	$146,000
Electrical (Male & Female)				
Substation - Cost Per Engineer	1	LS	2,000,000	$2,000,000
Electric Line / Ductbank / Manholes - Cost Per Engineer	15,000	LF	500.00	$7,500,000
Security (Male)				
Cameras / Equipment	1	LS	350,000	$350,000
				$16,019,000

SECTION	QUANTITY	UNIT	UNIT COST	COST

OFF-SITE UTILITIES (Male & Female)

OFF-SITE UTILITIES (Male & Female)

SECTION	QUANTITY	UNIT	UNIT COST	COST
Sanitary Sewer				
Sanitary Sewer Line w/ Manholes	6,166	LF	90.00	$555,000
Waste Water Storage Pond	615,332	CY	3.00	$1,846,000
Waste Water Plant - Cost per Engineer	1	LS	4,617,000	$4,617,000
Storm Drain				
Storm Drainage Line	500	LF	160.00	$80,000
Detention Pond	12,330	CY	4.00	$49,000
Water				
Water Line	7,830	LF	130.00	$1,018,000
Well	2	EA	250,000	$500,000
Tank - 750,000 Gallon	2	EA	750,000	$1,500,000
Water Connection Fee - Cost Per Engineer	1	LS	97,960	$98,000
Meter Vault - Cost Per Engineer	1	LS	70,000	$70,000
Gas				
Gas Line	2,360	LF	60.00	$142,000
High Pressure Piping - Cost Per Engineer	1	LS	100,000	$100,000
Meter Facility - Cost Per Engineer	1	LS	100,000	$100,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 6,000 BEDS

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SECTION	QUANTITY	UNIT	UNIT COST	COST
OFF-SITE IMPROVEMENTS (Male & Female) - Continued				
OFF-SITE UTILITIES (Male & Female) - Continued				
Voice / Data				
Road Duct - Cost Per Engineer	20	MILES	221,760	$4,435,000
Fiber Optic Line - Cost Per Engineer	20	MILES	11,616	$232,000
Electrical				
Substation - Cost Per Engineer	1	LS	2,000,000	$2,000,000
Electric Line - Cost Per Engineer	8.5	MILES	350,000	$2,975,000
				$20,317,000
TOTAL (Construction)				**$787,708,000**
SOFT COSTS - 25.0%				**$196,927,000**
TOTAL				**$984,635,000**

NOTES: Costs Include Contractor General Conditions, Overhead & Profit.
Costs are Based on a Competitive Bid Basis Between 3-4 Bidders.
Costs are Current Costs and Do Not Include Inflation. For Inflation Add 6.0% per Year.
Soft Costs Are: A/E Fees, FF&E, Contingency and Owner Costs.
Costs Do Not Include Land or Finance Costs.

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 10,000 BEDS

Order of Magnitude Cost Estimate
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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
INSIDE SECURE PERIMETER				$74,234,000
HOUSING (10 Pods)				$735,068,000
OUTSIDE SECURE PERIMETER				$40,630,000
PERIMETER CONTROL				$7,043,000
ON-SITE MISCELLANEOUS IMPROVEMENTS				$5,110,000
				$862,085,000
BUILDINGS - FEMALE FACILITY				
INSIDE SECURE PERIMETER				$28,206,000
HOUSING (2 Pods)				$136,637,000
OUTSIDE SECURE PERIMETER				$5,680,000
PERIMETER CONTROL				$3,573,000
ON-SITE MISCELLANEOUS IMPROVEMENTS				$709,000
				$174,805,000
ON-SITE UTILITIES (Male & Female)				$16,119,000
OFF-SITE UTILITIES (Male & Female)				$23,395,000
TOTAL (Construction)				$1,076,404,000
SOFT COSTS - 25.0%				$269,101,000
TOTAL				$1,345,505,000

NOTES: Costs Include Contractor General Conditions, Overhead & Profit.
Costs are Based on a Competitive Bid Basis Between 3-4 Bidders.
Costs are Current Costs and Do Not Include Inflation. For Inflation Add 6.0% per Year.
Soft Costs Are: A/E Fees, FF&E, Contingency and Owner Costs.
Costs Do Not Include Land or Finance Costs.

RUSH VALLEY SITE - 10,000 BEDS

Order of Magnitude Cost Estimate
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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
INSIDE SECURE PERIMETER				
Central Services	17,100	SF	275.00	$4,703,000
Religious Facilities	37,400	SF	285.00	$10,659,000
Health Care	19,250	SF	350.00	$6,738,000
Reception / Orientation	6,250	SF	285.00	$1,781,000
Plant Maintenance	6,000	SF	250.00	$1,500,000
Laundry	12,100	SF	400.00	$4,840,000
Refuse Station - Docks, Compactors, Recycling	2,000	SF	250.00	$500,000
Culinary - Cook / Chill Facility	45,000	SF	435.00	$19,575,000
Industries	85,000	SF	225.00	$19,125,000
Medical Unit	12,500	SF	385.00	$4,813,000
				$74,234,000

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
HOUSING (10 Pods)				
Special Pop - Complex One (638 Beds)	206,800	SF	365.00	$75,482,000
Intake Classification:				
(1) 32 Bed Unit, Dorm				
(1) 192 Module, Single Bunked				
(2) 32 Mental Health Units, Dorm				
Mental Health Observation:				
(64) Double Cell Beds				
(32) Single Cell Beds				
(72) Dorm Beds				
Sub-Acute Mental Health:				
(4) 16 Double Bed Units				
Infirmary:				
(54) Infirmary				
Special Pop - Complex One (576 Beds)	194,400	SF	375.00	$72,900,000
(2) 192 Modules, Double Bunked				
(1) 192 Modules, Single Bunked				
Special Pop - Complex Two (384 Beds)	194,400	SF	380.00	$73,872,000
(2) 192 Modules, Single Bunked				

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 10,000 BEDS

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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
HOUSING (10 Pods) - Continued				
Level Three - Complex One (960 Beds)	214,700	SF	340.00	$72,998,000
(2) 192 Modules, Double Bunked				
(2) 288 Modules, Dorms				
Level Three - Complex Two (864 Beds)	205,800	SF	350.00	$72,030,000
(3) 192 Modules, Double Bunked				
(1) 288 Modules, Dorms				
Level Three - Complex Three (864 Beds)	205,800	SF	350.00	$72,030,000
(3) 192 Modules, Double Bunked				
(1) 288 Modules, Dorms				
Levels Four & Five (1,152 Beds)	244,000	SF	315.00	$76,860,000
(4) 288 Modules, Dorms				
Special Pop - Complex A1 (960 Beds)	214,700	SF	340.00	$72,998,000
(2) 192 Modules, Double Bunked				
(2) 288 Modules, Dorms				
Levels 1 & 2 - Complex A2 (672 Beds)	194,400	SF	375.00	$72,900,000
(1) 168 Modules, Single Bunked				
(3) 168 Modules, Double Bunked				
Level 3 - Complex A3 (960 Beds)	214,700	SF	340.00	$72,998,000
(2) 192 Modules, Double Bunked				
(2) 288 Modules, Dorms				
				$735,068,000

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NEW PRISON FACILITY

RUSH VALLEY SITE - 10,000 BEDS

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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
OUTSIDE SECURE PERIMETER				
Administration	28,500	SF	215.00	$6,128,000
Enforcement Center	5,000	SF	275.00	$1,375,000
Plant Services				
Vehicle Maintenance	7,000	SF	200.00	$1,400,000
Staff Parking	8,750	SF	6.00	$53,000
Covered Parking	7,000	SF	25.00	$175,000
Motor Pool	29,750	SF	65.00	$1,934,000
Fuel Station	5,000	SF	350.00	$1,750,000
Central Plant	15,000	SF	1,000	$15,000,000
Warehouse				
General Warehouse - Supplies, Canteen, Property & Mail	42,000	SF	125.00	$5,250,000
Outside Covered Storage	2,000	SF	25.00	$50,000
Fenced Storage Yard	10,000	SF	20.00	$200,000
Parking	8,750	SF	6.00	$53,000
Paved Area	60,000	SF	6.00	$360,000
Perimeter Security Towers (8 EA)	3,200	SF	1,800	$5,760,000
Site Traffic Station				
Site Traffic Station	1,250	SF	125.00	$156,000
Parking, Pullouts & Turnarounds	8,500	SF	10.00	$85,000
Lighting	20	EA	4,000	$80,000
Kennels				
Dog Kennels	500	SF	350.00	$175,000
Runs	750	SF	110.00	$83,000
Training Area	2,500	SF	225.00	$563,000
				$40,630,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

RUSH VALLEY SITE - 10,000 BEDS

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SECTION	QUANTITY	UNIT	UNIT COST	COST
ON-SITE IMPROVEMENTS - MALE FACILITY				
PERIMETER CONTROL				
Vehicle Sallyport				
Gatehouse	150	SF	325.00	$49,000
Fenced Enclosure	10,000	SF	20.00	$200,000
Perimeter Road	414,000	SF	3.00	$1,242,000
Perimeter Fence - Double	12,800	LF	315.00	$4,032,000
Perimeter Fence Electronics	12,800	LF	100.00	$1,280,000
Perimeter Lighting	20	EA	12,000	$240,000
				$7,043,000
ON-SITE IMPROVEMENTS - MALE FACILITY				
ON-SITE MISCELLANEOUS IMPROVEMENTS				
Parking				
Staff Parking	175,000	SF	6.00	$1,050,000
Visitor Parking	70,000	SF	6.00	$420,000
Landscaping				
Seed / Landscaping (Minimal)	600,000	SF	0.15	$90,000
Other				
Security Fence	15,750	LF	160.00	$2,520,000
Fenced Yard - Plant Maintenance	5,000	SF	20.00	$100,000
Paved Area - Special Pop, Industries, Etc.	135,000	SF	6.00	$810,000
Site Lighting	30	EA	4,000	$120,000
				$5,110,000

RUSH VALLEY SITE - 10,000 BEDS

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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - FEMALE FACILITY				
INSIDE SECURE PERIMETER				
Central Services	17,100	SF	275.00	$4,703,000
Religious Facilities	17,300	SF	285.00	$4,931,000
Health Care	10,100	SF	350.00	$3,535,000
Reception / Orientation	3,550	SF	285.00	$1,012,000
Plant Maintenance	6,000	SF	250.00	$1,500,000
Laundry	6,000	SF	400.00	$2,400,000
Refuse Station - Docks, Compactors, Recycling	2,000	SF	250.00	$500,000
Industries	40,000	SF	225.00	$9,000,000
Warehouse	5,000	SF	125.00	$625,000
				$28,206,000

RUSH VALLEY SITE - 10,000 BEDS

Order of Magnitude Cost Estimate
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SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - FEMALE FACILITY				
HOUSING (2 Pods)				
Special Housing / General Population	167,146	SF	375.00	$62,680,000
Support	52,000	SF	290.00	$15,080,000
Special Pop - Complex A1 (720 Beds) (1) 144 Modules, Single Bunked (2) 288 Modules, Double Bunked	173,167	SF	340.00	$58,877,000
				$136,637,000
BUILDINGS - FEMALE FACILITY				
OUTSIDE SECURE PERIMETER				
Administration	15,100	SF	215.00	$3,247,000
Site Traffic Station				
Site Traffic Station	1,250	SF	125.00	$156,000
Parking, Pullouts & Turnarounds	8,500	SF	10.00	$85,000
Lighting	8	EA	4,000	$32,000
Perimeter Security Towers (3 EA)	1,200	SF	1,800	$2,160,000
				$5,680,000

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NEW PRISON FACILITY

RUSH VALLEY SITE - 10,000 BEDS

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ON-SITE IMPROVEMENTS - FEMALE FACILITY

PERIMETER CONTROL

SECTION	QUANTITY	UNIT	UNIT COST	COST
Vehicle Sallyport				
Gatehouse	150	SF	325.00	$49,000
Fenced Enclosure	10,000	SF	20.00	$200,000
Perimeter Road	181,500	SF	3.00	$545,000
Perimeter Fence - Double	6,350	LF	315.00	$2,000,000
Perimeter Fence Electronics	6,350	LF	100.00	$635,000
Perimeter Lighting	12	EA	12,000	$144,000
				$3,573,000

ON-SITE IMPROVEMENTS - FEMALE FACILITY

ON-SITE MISCELLANEOUS IMPROVEMENTS

SECTION	QUANTITY	UNIT	UNIT COST	COST
Parking				
Staff Parking	35,000	SF	6.00	$210,000
Visitor Parking	26,250	SF	6.00	$158,000
Landscaping				
Seed / Landscaping (Minimal)	337,500	SF	0.15	$51,000
Other				
Fenced Yard - Plant Maintenance	5,000	SF	20.00	$100,000
Paved Area - Warehouse, Support & Refuse Station	25,000	SF	6.00	$150,000
Site Lighting	10	EA	4,000	$40,000
				$709,000

SECTION	QUANTITY	UNIT	UNIT COST	COST
ON-SITE UTILITIES (Male & Female)				
ON-SITE UTILITIES (Male & Female)				
Sanitary Sewer (Male & Female)				
Sewage Grinder Facility	150	SF	1,000	$150,000
Sanitary Sewer Line w/ Manholes	9,480	LF	90.00	$853,000
Grease Trap	8	EA	30,000	$240,000
Grinder	8	EA	55,000	$440,000
Storm Drain (Male & Female)				
Storm Drainage Line w/ Catch Basins	16,676	LF	110.00	$1,834,000
Water (Male & Female)				
Pump House	175	SF	750.00	$131,000
Water Line w/ Hydrants	19,450	LF	100.00	$1,945,000
Gas (Male & Female)				
Gas Line	12,285	LF	35.00	$430,000
Voice / Data (Male & Female)				
Fiber Optic Line / Racks & Connectivity - Cost Per Engineer	1	LS	146,000	$146,000
Electrical (Male & Female)				
Substation - Cost Per Engineer	1	LS	2,000,000	$2,000,000
Electric Line / Ductbank / Manholes - Cost Per Engineer	15,000	LF	500.00	$7,500,000
Security (Male)				
Cameras / Equipment	1	LS	450,000	$450,000
				$16,119,000

OFF-SITE UTILITIES (Male & Female)

OFF-SITE UTILITIES (Male & Female)

SECTION	QUANTITY	UNIT	UNIT COST	COST
Sanitary Sewer				
Sanitary Sewer Line w/ Manholes	6,166	LF	90.00	$555,000
Waste Water Storage Pond	615,332	CY	3.00	$1,846,000
Waste Water Plant - Cost per Engineer	1	LS	7,695,000	$7,695,000
Storm Drain				
Storm Drainage Line	500	LF	160.00	$80,000
Detention Pond	12,330	CY	4.00	$49,000
Water				
Water Line	7,830	LF	130.00	$1,018,000
Well	2	EA	250,000	$500,000
Tank - 750,000 Gallon	2	EA	750,000	$1,500,000
Water Connection Fee - Cost Per Engineer	1	LS	97,960	$98,000
Meter Vault - Cost Per Engineer	1	LS	70,000	$70,000
Gas				
Gas Line	2,360	LF	60.00	$142,000
High Pressure Piping - Cost Per Engineer	1	LS	100,000	$100,000
Meter Facility - Cost Per Engineer	1	LS	100,000	$100,000

SECTION	QUANTITY	UNIT	UNIT COST	COST
OFF-SITE IMPROVEMENTS (Male & Female) - Continued				
OFF-SITE UTILITIES (Male & Female) - Continued				
Voice / Data				
Road Duct - Cost Per Engineer	20	MILES	221,760	$4,435,000
Fiber Optic Line - Cost Per Engineer	20	MILES	11,616	$232,000
Electrical				
Substation - Cost Per Engineer	1	LS	2,000,000	$2,000,000
Electric Line - Cost Per Engineer	8.5	MILES	350,000	$2,975,000
				$23,395,000
TOTAL (Construction)				**$1,076,404,000**
SOFT COSTS - 25.0%				**$269,101,000**
TOTAL				**$1,345,505,000**

NOTES: Costs Include Contractor General Conditions, Overhead & Profit.
Costs are Based on a Competitive Bid Basis Between 3-4 Bidders.
Costs are Current Costs and Do Not Include Inflation. For Inflation Add 6.0% per Year.
Soft Costs Are: A/E Fees, FF&E, Contingency and Owner Costs.
Costs Do Not Include Land or Finance Costs.

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
INSIDE SECURE PERIMETER				$74,234,000
HOUSING (7 Pods)				$516,172,000
OUTSIDE SECURE PERIMETER				$36,510,000
PERIMETER CONTROL				$5,733,000
ON-SITE MISCELLANEOUS IMPROVEMENTS				$4,447,000
				$637,096,000
BUILDINGS - FEMALE FACILITY				
INSIDE SECURE PERIMETER				$28,206,000
HOUSING (1 Pod)				$77,760,000
OUTSIDE SECURE PERIMETER				$4,952,000
PERIMETER CONTROL				$2,665,000
ON-SITE MISCELLANEOUS IMPROVEMENTS				$693,000
				$114,276,000
ON-SITE UTILITIES (Male & Female)				$16,019,000
OFF-SITE UTILITIES (Male & Female)				$11,064,000
TOTAL (Construction)				$778,455,000
SOFT COSTS - 25.0%				$194,614,000
TOTAL				$973,069,000

NOTES: Costs Include Contractor General Conditions, Overhead & Profit.
Costs are Based on a Competitive Bid Basis Between 3-4 Bidders.
Costs are Current Costs and Do Not Include Inflation. For Inflation Add 6.0% per Year.
Soft Costs Are: A/E Fees, FF&E, Contingency and Owner Costs.
Costs Do Not Include Land or Finance Costs.

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
INSIDE SECURE PERIMETER				
Central Services	17,100	SF	275.00	$4,703,000
Religious Facilities	37,400	SF	285.00	$10,659,000
Health Care	19,250	SF	350.00	$6,738,000
Reception / Orientation	6,250	SF	285.00	$1,781,000
Plant Maintenance	6,000	SF	250.00	$1,500,000
Laundry	12,100	SF	400.00	$4,840,000
Refuse Station - Docks, Compactors, Recycling	2,000	SF	250.00	$500,000
Culinary - Cook / Chill Facility	45,000	SF	435.00	$19,575,000
Industries	85,000	SF	225.00	$19,125,000
Medical Unit	12,500	SF	385.00	$4,813,000
				$74,234,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
HOUSING (7 Pods)				
Special Pop - Complex One (638 Beds)	206,800	SF	365.00	$75,482,000
Intake Classification:				
(1) 32 Bed Units, Dorm				
(1) 192 Modules, Single Bunked				
(2) 32 Mental Health Units, Dorm				
Mental Health Observation:				
(64) Double Cell Beds				
(32) Single Cell Beds				
(72) Dorm Beds				
Sub-Acute Mental Health:				
(4) 16 Double Bed Units				
Infirmary:				
(54) Infirmary				
Special Pop - Complex One (576 Beds)	194,400	SF	375.00	$72,900,000
(2) 192 Modules, Double Bunked				
(1) 192 Modules, Single Bunked				
Special Pop - Complex Two (384 Beds)	194,400	SF	380.00	$73,872,000
(2) 192 Modules, Single Bunked				
Level Three - Complex One (960 Beds)	214,700	SF	340.00	$72,998,000
(2) 192 Modules, Double Bunked				
(2) 288 Modules, Dorms				
Level Three - Complex Two (864 Beds)	205,800	SF	350.00	$72,030,000
(3) 192 Modules, Double Bunked				
(1) 288 Modules, Dorms				

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
HOUSING (7 Pods) - Continued				
Level Three - Complex Three (864 Beds) (3) 192 Modules, Double Bunked (1) 288 Modules, Dorms	205,800	SF	350.00	$72,030,000
Levels Four & Five (1,152 Beds) (4) 288 Modules, Dorms	244,000	SF	315.00	$76,860,000
				$516,172,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - MALE FACILITY				
OUTSIDE SECURE PERIMETER				
Administration	28,500	SF	215.00	$6,128,000
Enforcement Center	5,000	SF	275.00	$1,375,000
Plant Services				
Vehicle Maintenance	7,000	SF	200.00	$1,400,000
Staff Parking	8,750	SF	6.00	$53,000
Covered Parking	7,000	SF	25.00	$175,000
Motor Pool	29,750	SF	65.00	$1,934,000
Fuel Station	5,000	SF	350.00	$1,750,000
Central Plant	15,000	SF	1,000	$15,000,000
Warehouse				
General Warehouse - Supplies, Canteen, Property & Mail	22,000	SF	125.00	$2,750,000
Outside Covered Storage	2,000	SF	25.00	$50,000
Fenced Storage Yard	10,000	SF	20.00	$200,000
Parking	8,750	SF	6.00	$53,000
Paved Area	30,000	SF	6.00	$180,000
Perimeter Security Towers (6 EA)	2,400	SF	1,800	$4,320,000
Site Traffic Station				
Site Traffic Station	1,250	SF	125.00	$156,000
Parking, Pullouts & Turnarounds	8,500	SF	10.00	$85,000
Lighting	20	EA	4,000	$80,000
Kennels				
Dog Kennels	500	SF	350.00	$175,000
Runs	750	SF	110.00	$83,000
Training Area	2,500	SF	225.00	$563,000
				$36,510,000

ON-SITE IMPROVEMENTS - MALE FACILITY

PERIMETER CONTROL

SECTION	QUANTITY	UNIT	UNIT COST	COST
Vehicle Sallyport				
Gatehouse	150	SF	325.00	$49,000
Fenced Enclosure	10,000	SF	20.00	$200,000
Perimeter Road	339,000	SF	3.00	$1,017,000
Perimeter Fence - Double	10,300	LF	315.00	$3,245,000
Perimeter Fence Electronics	10,300	LF	100.00	$1,030,000
Perimeter Lighting	16	EA	12,000	$192,000
				$5,733,000

ON-SITE IMPROVEMENTS - MALE FACILITY

ON-SITE MISCELLANEOUS IMPROVEMENTS

SECTION	QUANTITY	UNIT	UNIT COST	COST
Parking				
Staff Parking	175,000	SF	6.00	$1,050,000
Visitor Parking	70,000	SF	6.00	$420,000
Landscaping				
Seed / Landscaping (Minimal)	475,000	SF	0.15	$71,000
Other				
Security Fence	13,000	LF	160.00	$2,080,000
Fenced Yard - Plant Maintenance	5,000	SF	20.00	$100,000
Paved Area - Special Pop, Industries, Etc.	105,000	SF	6.00	$630,000
Site Lighting	24	EA	4,000	$96,000
				$4,447,000

BUILDINGS - FEMALE FACILITY

INSIDE SECURE PERIMETER

SECTION	QUANTITY	UNIT	UNIT COST	COST
Central Services	17,100	SF	275.00	$4,703,000
Religious Facilities	17,300	SF	285.00	$4,931,000
Health Care	10,100	SF	350.00	$3,535,000
Reception / Orientation	3,550	SF	285.00	$1,012,000
Plant Maintenance	6,000	SF	250.00	$1,500,000
Laundry	6,000	SF	400.00	$2,400,000
Refuse Station - Docks, Compactors, Recycling	2,000	SF	250.00	$500,000
Industries	40,000	SF	225.00	$9,000,000
Warehouse	5,000	SF	125.00	$625,000
				$28,206,000

UTAH STATE PRISON MASTERPLAN
NEW PRISON FACILITY

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

SECTION	QUANTITY	UNIT	UNIT COST	COST
BUILDINGS - FEMALE FACILITY				
HOUSING (1 Pod)				
Special Housing / General Population	167,146	SF	375.00	$62,680,000
Support	52,000	SF	290.00	$15,080,000
				$77,760,000
BUILDINGS - FEMALE FACILITY				
OUTSIDE SECURE PERIMETER				
Administration	15,100	SF	215.00	$3,247,000
Site Traffic Station				
Site Traffic Station	1,250	SF	125.00	$156,000
Parking, Pullouts & Turnarounds	8,500	SF	10.00	$85,000
Lighting	6	EA	4,000	$24,000
Perimeter Security Towers (2 EA)	800	SF	1,800	$1,440,000
				$4,952,000

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

ON-SITE IMPROVEMENTS - FEMALE FACILITY

PERIMETER CONTROL

SECTION	QUANTITY	UNIT	UNIT COST	COST
Vehicle Sallyport				
Gatehouse	150	SF	325.00	$49,000
Fenced Enclosure	10,000	SF	20.00	$200,000
Perimeter Road	129,000	SF	3.00	$387,000
Perimeter Fence - Double	4,600	LF	315.00	$1,449,000
Perimeter Fence Electronics	4,600	LF	100.00	$460,000
Perimeter Lighting	10	EA	12,000	$120,000
				$2,665,000

ON-SITE IMPROVEMENTS - FEMALE FACILITY

ON-SITE MISCELLANEOUS IMPROVEMENTS

SECTION	QUANTITY	UNIT	UNIT COST	COST
Parking				
Staff Parking	35,000	SF	6.00	$210,000
Visitor Parking	26,250	SF	6.00	$158,000
Landscaping				
Seed / Landscaping (Minimal)	285,000	SF	0.15	$43,000
Other				
Fenced Yard - Plant Maintenance	5,000	SF	20.00	$100,000
Paved Area - Warehouse, Support & Refuse Station	25,000	SF	6.00	$150,000
Site Lighting	8	EA	4,000	$32,000
				$693,000

SECTION	QUANTITY	UNIT	UNIT COST	COST

ON-SITE UTILITIES (Male & Female)

ON-SITE UTILITIES (Male & Female)

SECTION	QUANTITY	UNIT	UNIT COST	COST
Sanitary Sewer (Male & Female)				
Sewage Grinder Facility	150	SF	1,000	$150,000
Sanitary Sewer Line w/ Manholes	9,480	LF	90.00	$853,000
Grease Trap	8	EA	30,000	$240,000
Grinder	8	EA	55,000	$440,000
Storm Drain (Male & Female)				
Storm Drainage Line w/ Catch Basins	16,676	LF	110.00	$1,834,000
Water (Male & Female)				
Pump House	175	SF	750.00	$131,000
Water Line w/ Hydrants	19,450	LF	100.00	$1,945,000
Gas (Male & Female)				
Gas Line	12,285	LF	35.00	$430,000
Voice / Data (Male & Female)				
Fiber Optic Line / Racks & Connectivity - Cost Per Engineer	1	LS	146,000	$146,000
Electrical (Male & Female)				
Substation - Cost Per Engineer	1	LS	2,000,000	$2,000,000
Electric Line / Ductbank / Manholes - Cost Per Engineer	15,000	LF	500.00	$7,500,000
Security (Male)				
Cameras / Equipment	1	LS	350,000	$350,000
				$16,019,000

SECTION	QUANTITY	UNIT	UNIT COST	COST

OFF-SITE UTILITIES (Male & Female)

OFF-SITE UTILITIES (Male & Female)

Sanitary Sewer				
Sanitary Sewer Line w/ Manholes	3,340	LF	90.00	$301,000
Waste Water Storage Pond	615,332	CY	3.00	$1,846,000
Waste Water Plant - Cost per Engineer	1	LS	4,617,000	$4,617,000
Storm Drain				
Storm Drainage Line	500	LF	160.00	$80,000
Detention Pond	12,330	CY	4.00	$49,000
Water				
Water Line	3,800	LF	130.00	$494,000
Water Connection Fee - Cost Per Engineer	1	LS	97,960	$98,000
Meter Vault - Cost Per Engineer	1	LS	70,000	$70,000
Gas				
Gas Line	2,360	LF	60.00	$142,000
High Pressure Piping - Cost Per Engineer	1	LS	100,000	$100,000
Meter Facility - Cost Per Engineer	1	LS	100,000	$100,000

DRAPER SITE - 6,000 BEDS

Order of Magnitude Cost Estimate
December 19, 2008

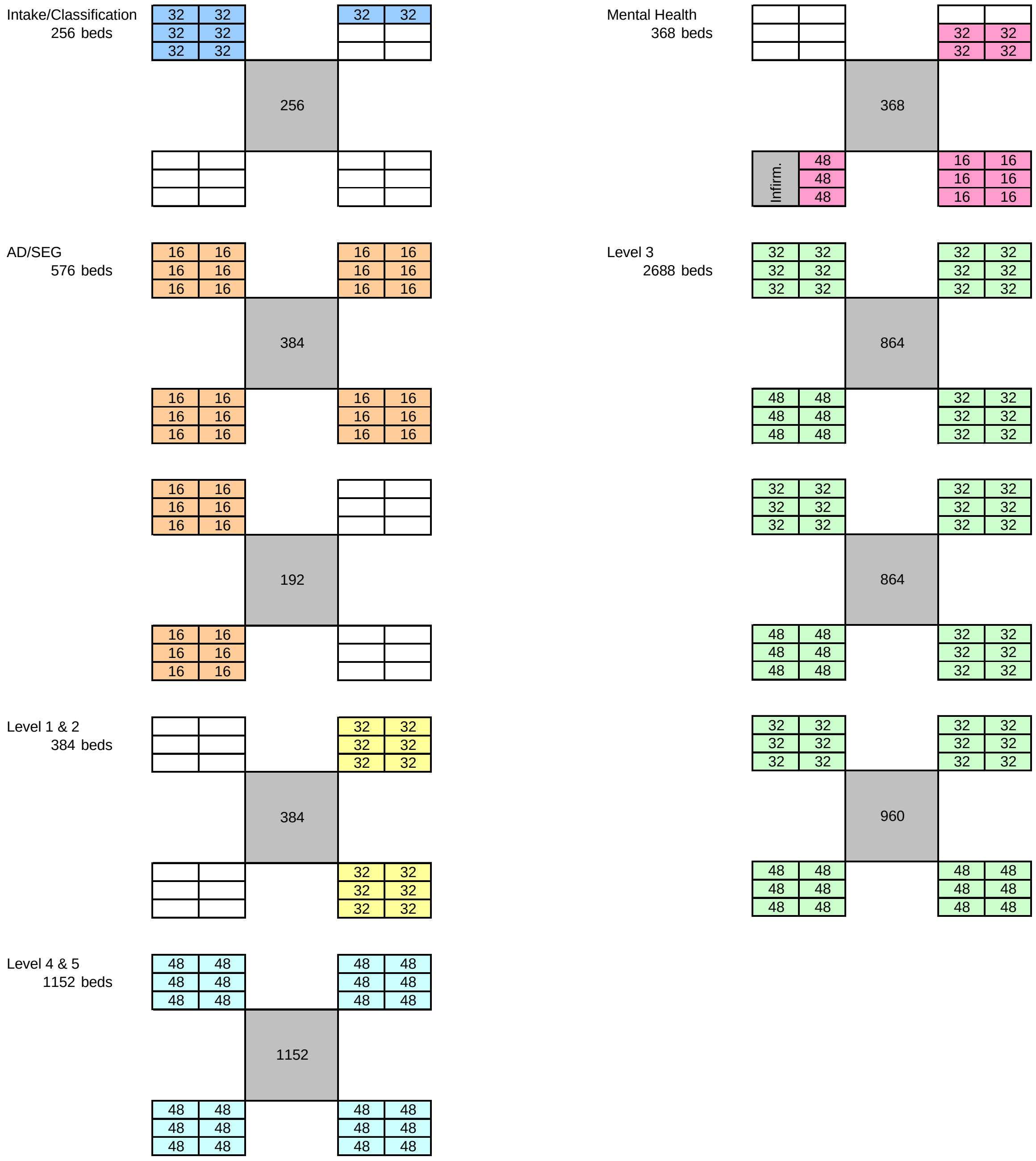
SECTION	QUANTITY	UNIT	UNIT COST	COST
OFF-SITE IMPROVEMENTS (Male & Female) - Continued				
OFF-SITE UTILITIES (Male & Female) - Continued				
Voice / Data				
Road Duct	2	MILES	221,760	$444,000
Fiber Optic Line	2	MILES	11,616	$23,000
Electrical				
Substation	1	LS	2,000,000	$2,000,000
Electric Line	2	MILES	350,000	$700,000
				$11,064,000
TOTAL (Construction)				**$778,455,000**
SOFT COSTS - 25.0%				**$194,614,000**
TOTAL				**$973,069,000**

NOTES: Costs Include Contractor General Conditions, Overhead & Profit.
Costs are Based on a Competitive Bid Basis Between 3-4 Bidders.
Costs are Current Costs and Do Not Include Inflation. For Inflation Add 6.0% per Year.
Soft Costs Are: A/E Fees, FF&E, Contingency and Owner Costs.
Costs Do Not Include Land or Finance Costs.

Appendix

Male Population Bed Count Deployment – By Management Segregation

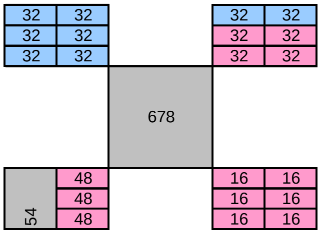
Phase 1



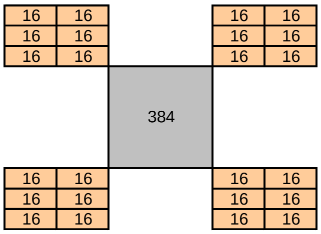
Male Population Bed Count Deployment – As Configured in Concept Site Plan Illustrations

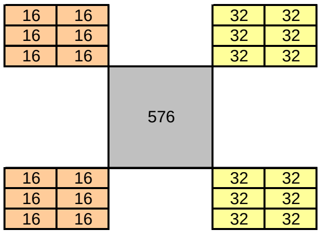
Phase 1

Intake/Release – Mental Health Complex

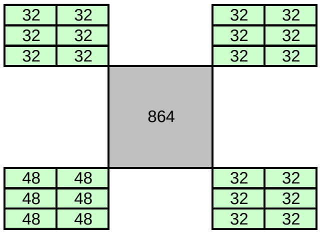


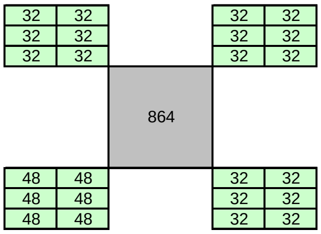
Adminstrative Segregation – Level 1 & 2 Complex

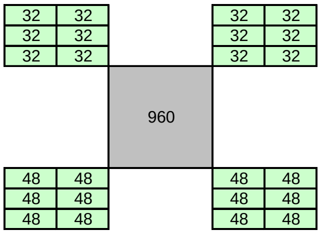




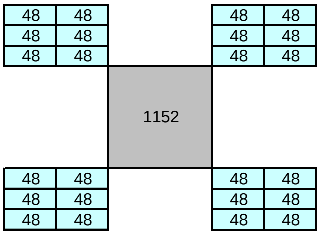
Level 3 Complex





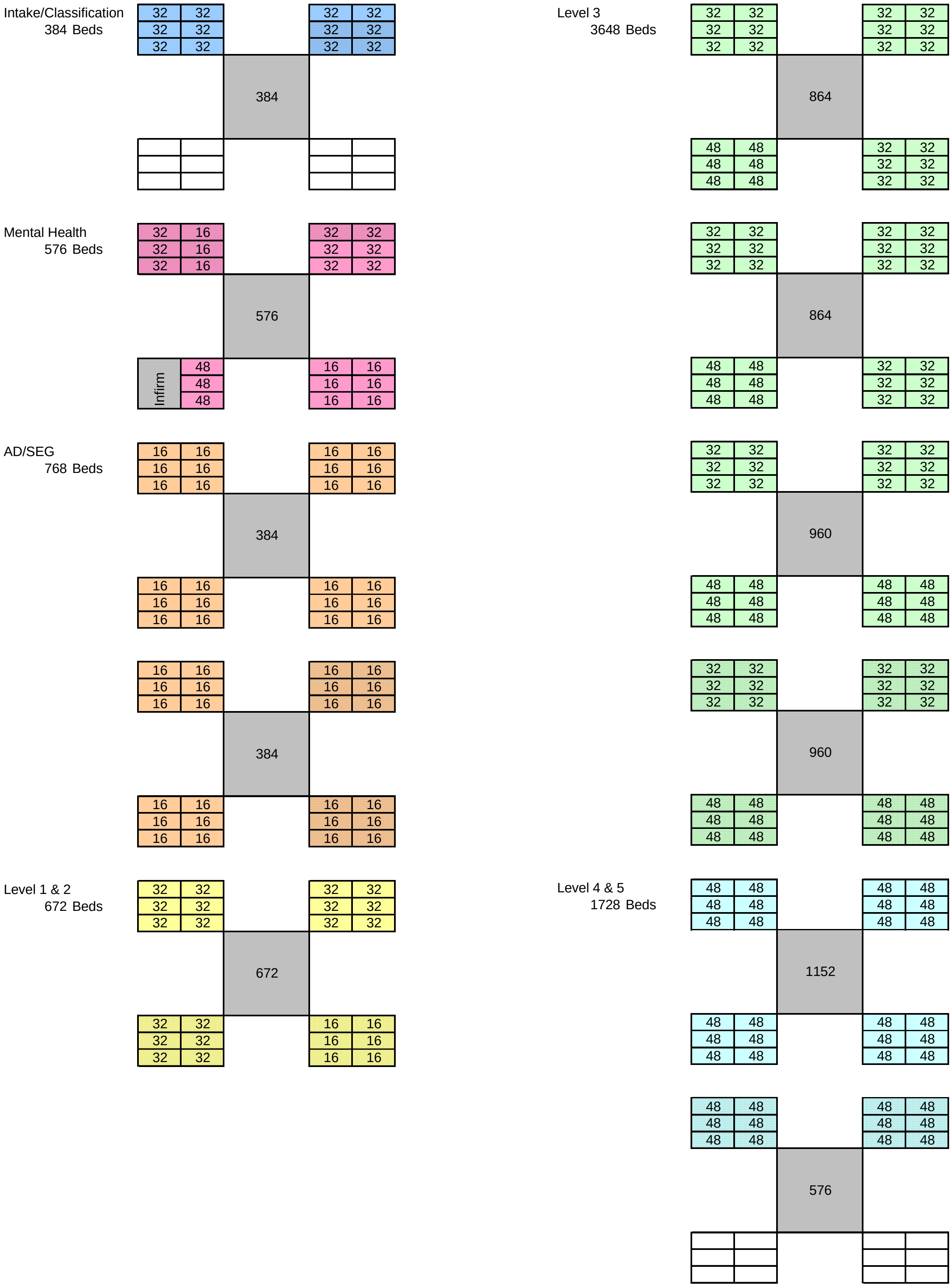


Level 4 & 5 Complex



Male Population Bed Count Deployment – By Management Segregation

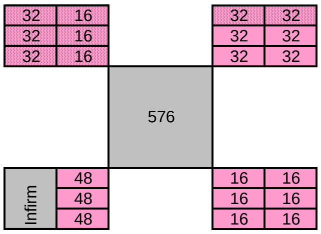
Phase 2



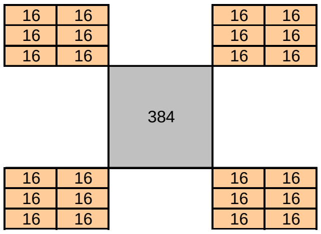
Male Population Bed Count Deployment – As Configured in Concept Site Plan Illustrations

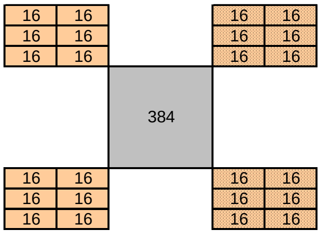
Phase 2

Mental Health Complex

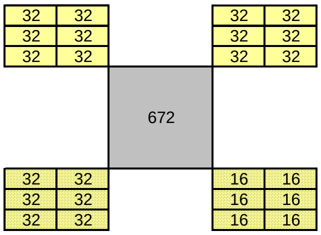


Adminstrative Segregation

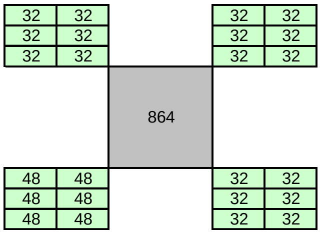


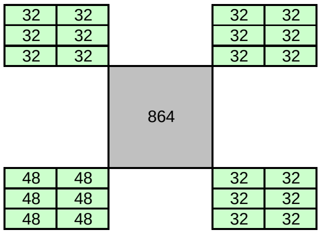


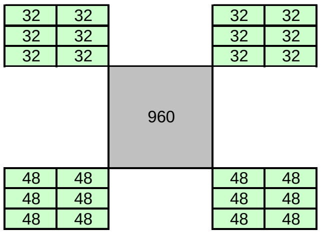
Level 1 & 2 Complex

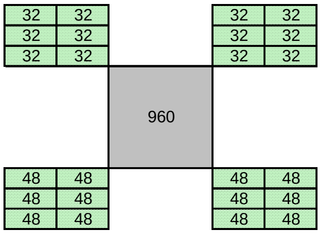


Level 3 Complex

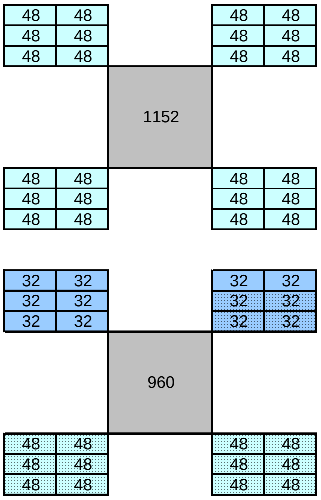








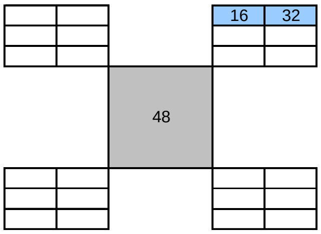
Level 4 & 5 Complex – Intake Classification



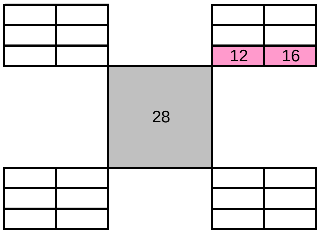
Female Population Bed Count Deployment – By Management Segregation

Phase 1

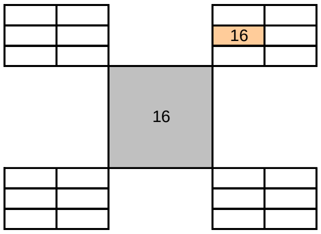
Intake/Classification
48



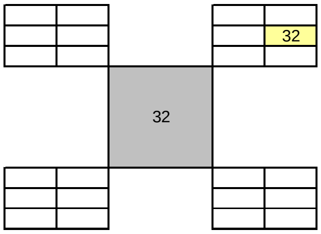
Mental Health
28



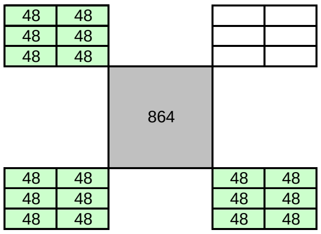
AD/SEG
16



Level 1/2
32

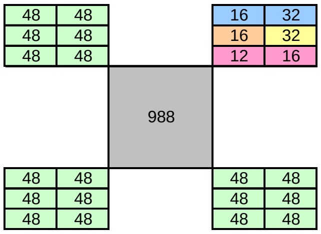


Level 3
864



Female Population Bed Count Deployment – As Configured in Concept Site Plan Illustrations

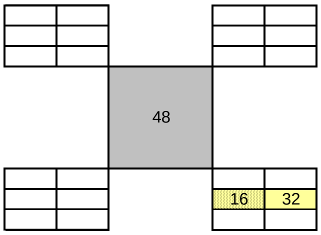
Phase 1



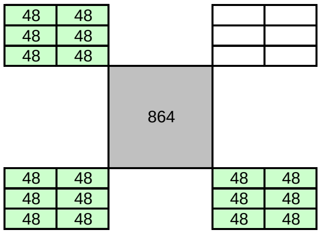
Female Population Bed Count Deployment – By Management Segregation

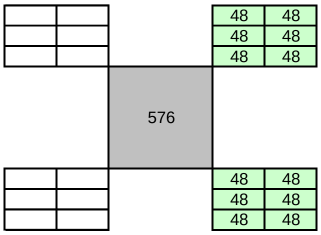
Phase 2

Level 1/2
48

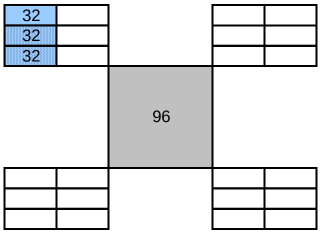


Level 3
1440

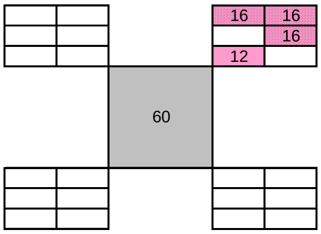




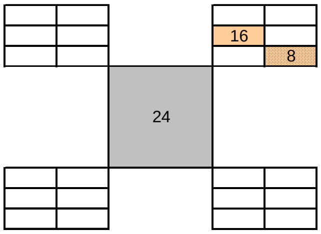
Intake/Classification
96



Mental Health
60



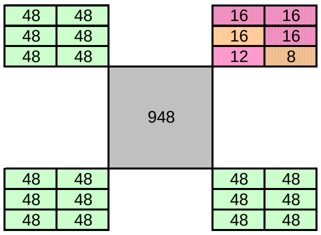
AD/SEG
24



Female Population Bed Count Deployment – As Configured in Concept Site Plan Illustrations

Phase 2

Mental Health – Administrative Segregation – Level 3 Complex



Level ½ – Level 3 – Intake Classification Complex