PACESETTER UTILITY NV Energy

Edward W Clark Generating Station

Las Vegas, Nev

Complete makeover

The Edward W Clark Generating Station transformed Southern Nevada Power Co from a "wires" company into a vertically integrated utility (generation, transmission, distribution) when the state's first steam/electric plant began operating there in 1955. By way of background, Edward Clark was the first president of SNPC, the company he formed in 1929.

When the 44-MW Unit 1 went into service, the country and the electric power industry were dramatically different than they are today. At that time, Nevada had seven small electric utilities and only 16 generating plants with a total nameplate capacity of 597 MW, 98% of that hydro. The only other state in the union that did not have a steam plant was Idaho.

The mountain states—Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah, and Nevada—essentially were "undeveloped." They covered more than one-quarter of the Lower 48's land area but produced less than 5% of all the electricity consumed in the US.

Clark Station has maintained its leadership position within the company since commissioning. Recently, a complete makeover of the plant's assets has helped position NV Energy among the top utilities in the nation in terms of environmental performance and renewables commitment. In brief, generating capability has been increased by 117%, to a nominal

Clark Station is located with the city limits of Las Vegas. When the first steam/electric unit began commercial operation in 1955, the plant stood all alone in the desert. No city would have been visible in an aerial photo like this one. Today the plant is surrounded by an interstate highway, commercial buildings, and residential neighborhoods. You can even see the hotels and casinos on Las Vegas Blvd on the horizon. The company's first three steam units were demolished to make room for the 12 SwiftPacs, arranged in three blocks of four units each at the bottom of the photo. Two combined cycles incorporating the four rehabilitated 501B6s (Units 5-8) are at the upper left

1100 MW, while reducing emissions by nearly one-half on a tons-per-year basis. More specifically:

- The plant's four water-injected 501Bs with diffusion flame burners, which had been permitted for 103 ppm NO_x, have been converted to dry low NO_x combustors by PSM (Power Systems Mfg) LLC, Jupiter, Fla, and now operate at less than 5 ppm.
- Superannuated steam units have been replaced by12 SwiftPac® generating units (Pratt & Whitney Power Systems, East Hartford, Ct) to provide 600 MW of fast-start, low-emissions peaking capacity.

Former Plant Director Dariusz Rekowski, who was an active participant in the implementation of both projects, said the makeover has transformed Clark from a base-load facility to an intermediate-generation and peaking complex. Its strategic location on the grid, he added, makes the plant ideal for meeting short-term customer needs and for backing up intermittent solar and wind resources.


Rekowski

Rekowski is a well-liked and respected leader—an experienced engineer and manager comfortable with dirty hands. He joined the then Nevada Power Co in February 2006 as plant director of the Clark/Sunrise Complex, just as planning for the facility's future was revving up to full power. Sunrise is five miles from Clark and consists of a 1964-vintage, 82-MW steamer and a 501B3 simple-cycle machine.

Rekowski came from Dynegy Inc where he managed several unregulated GT-based plants in Kentucky and Ohio. He moved to corporate headquarters at the beginning of 2009 as O&M director with responsibility for work management, outage management, and unit availability/reliability improvement at the fleet level.

The editors met with Rekowski and key staff—including Plant Engineer Joe Cook and Operations Manager Steve Page (now acting plant director)—several times in the last nine months to gain the perspective needed to prepare this report. When Rekowski's office cleared after one meeting, he confided: "One of the unsung heroes of our many successful projects here at Clark Station in the past few years is Joe Cook. Not only did he do a great job of managing the PSM project for us, but he did it while serving admirably as our plant engineer. I constantly admired how he always was a calming and professional influence on our team and our vendor partners."

Plant history. Three steam/electric units were the first residents at Clark, which was a remote location when the station was opened. In addition to the 44-MW Unit 1, a 60-MW steam/electric Unit 2 began operating in 1957, followed by the 66-MW Unit 3 in 1961. A 54-MW GE Frame 7 peaker (designated Unit 4) was added in 1974.

Three of the four 501 gas turbines from Westinghouse Electric Corp were installed in 1979-1980; the last in 1982. The gas/oil-fired simple-cycle machines were purchased as B3s and upgraded to B5s during the conversion to combined-cycle operation. The upgrade to B6 came later.

The GTs designated Units 5 and 6 were converted to combined cycle in 1993 by addition of unfired heat-recovery steam generators (HRSGs) from Zurn Industries Inc, Erie, Pa (since renamed several times and now CMI-EPTI LLC) and a Westinghouse steam turbine. Addition of bypass stacks enabled each GT to maintain its ability to operate simple-cycle. Units 7 and 8 were converted to combined cycle in 1994. Oil capability was removed from the B6s before the millennium.

Units 1, 2, and 3 were retired in 2005. All were demolished in 2006, enabling site preparation for the SwiftPacs. No explosives were used to bring down the boilers; they were simply pulled down after strategic cuts were made in support members. This was anticlimactic in a city known for its spectacular implosions of old casinos.

Profiles of the DLN retrofit and peaker projects that follow offer valuable guidance for others reviewing the alternatives at their disposal for satisfying the often conflicting demands of regulators: Increase generating capability within the fence lines of legacy sites, increase availability and starting reliability, boost efficiency, reduce emissions, etc.

As you read through the profiles, your attention is focused on the contributions of NV Energy, EPC contractor CH2M Hill, PSM, Pratt & Whitney, and Peerless Mfg Co to the success of these projects. Not readily apparent is the critical role played by the talented skilled labor force that did the lion's share of the field work.

One construction manager on the project gave particularly high marks to the talented millwrights who call Las Vegas their home. About half of the two-dozen millwrights on the DLN retrofit and all the two-dozen or so assigned to installation of the SwiftPacs were affiliated with Local 1827 of the United Brotherhood of Carpenters and Joiners of America.

Interestingly, the Carpenter's International Training Center, which trains millwrights and offers an 18-month, university-level Superintendent Career Training Program, is only a proverbial "stone's throw" from Clark Station.

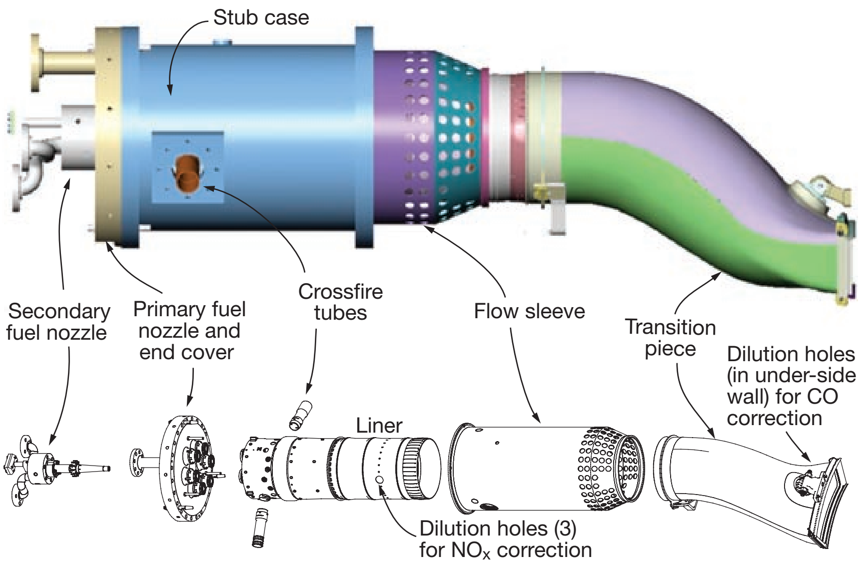
An "army" of electricians (162 at peak) was needed to install the SwiftPacs—about 20 times the number required for the DLN retrofit. Local contractor, Dynalectric Corp of Nevada, said the electricians assembled for the peaker project were affiliated with Vegas-based Local 357 of the International Brotherhood of Electrical Workers (IBEW) and clearly "the best in the West." This was a big project for Dynalectric and the schedule particularly challenging. Excellent craftsmanship, coordination, and leadership were critical to success, the company said. Dynalectric did all above- and below-ground electrical work, plus I&C.

Pipefitters—18 for the DLN project and about twice that number for the peaker installation—came from Plumbers and Pipefitters United Association Local 525.

Upgrading legacy GTs to meet challenging NO_x, CO permit limits

Industry veterans generally are aware how differently the EPA and powerplant owners define the terms "normal maintenance" and "modifications." Government broadly defines the latter as any physical or operational change that *could* increase emissions. A "modification" can result in new emissions limits and/or place a legacy unit under the operational requirements of NSPS (New Source Performance Standards) rules.

In June 2007, the Dept of Justice and EPA announced a major Clean Air Act (CAA) New Source Review (NSR) settlement with Nevada Power Co to resolve alleged CAA violations at Clark. As part of the settlement, the



4-1. Drop-in replacement for the DLN-1 in GE frames is shown at top. Stub case is used when the original compressor/combustor case is retained. It provides the additional space necessary for premixing of air and fuel. Arrangement at bottom (no stub case) was used for the Clark 501B6s because the new CC case required was designed to accommodate premixing

utility agreed to spend approximately \$60 million to install ultra-low-NO_x combustion systems on its four 501B6s before 2010, to dramatically reduce emissions from those units.

EPA said Nevada Power had violated the CAA "by undertaking construction activities at two combustion turbines" (Units 5 and 6) without first applying for an NSR permit, which would have required the utility "to take steps to reduce emissions at the time of the activities."

The alleged infraction: Recoating of turbine blades in 1988 with a material that would permit operation at higher firing temperatures, which are associated with increased NO_x emissions. The utility said the units never exceeded permit limits. Note that the Las Vegas Valley, home to the Clark generating facility, is a nonattainment area under the CAA for CO, PM10, and ozone.

Nevada Power began working collaboratively with government to resolve the issue about a year before the June 2007 public announcement. It engaged CH2M Hill to investigate options for reducing emissions at Clark. Among them: Use of a hot-end SCR at the GT exhaust and a cold-end SCR at the exit of the existing HRSG.

CH2M Hill's project manager, Doug Vandergriff, said the alternative selected—replacing the existing water-injected diffusion burners on the four GTs with dry low-emissions combustors from PSM (Power Systems Mfg) LLC, Jupiter, Fla—was considered by some to be a technological risk, but EPA was open minded enough to allow it as an option.

Risk is a relative term, of course. While PSM had never retrofitted a 501B6 with its LEC-III® combustion system, it had retrofitted two 501D5s at Calpine Corp's Texas City Cogeneration Power Plant a couple of years earlier with the same 12-can arrangement it proposed for Clark and that project was meeting expectations with an 80% reduction in NO_x emissions (access www.combinedcyclejournal.com/archives.html, click 4Q/2005, click "Portfolio of Pacesetting Plants" on issue cover).

Plus, PSM had successfully completed the conversion of two dozen other engines to the LEC-III, including five GE model 7E diffusion-flame GTs at Altura Cogen LLC (access 4Q/2007, click Altura Cogen on cover). Note that the LEC-III was originally designed as a drop-in alternative for the OEM's DLN-1 combustors on Frame 6B, 7E, and 9E machines (Fig 4-1).

PSM said its fleet experience through May 2009 shows that the LEC-III's premixed combustion process consistently yields sub-5-ppm NO_x levels and sub-10-ppm CO even when the engines are operating at minimum power. Depending on the engine, this could be as low as 50% of rated output. Also, several users are achieving 3 ppm NO_x—some even below that—throughout the operating range, and less than 2 ppm CO above 80% load. The LEC-III fleet leader has more than 40,000 hours of run time.

From a combustion-system perspective, what PSM proposed to Nevada Power was the conversion of Clark's "old technology" diffusion-flame B6 combustor system to a state-of-the-art low-emissions system based around the 7EA LEC-III combustion liner design. On a tons-per-year basis, the upgraded engines would reduce permitted NO_x emissions by 95%. Pressure ratio remained the same at 11:1.

PSM began exploratory work on the project in fall 2006. Project Integration Manager Charlie Ellis said his company essentially was in "design mode" by the end of that year. Engineers were gathering information needed to understand exactly what had to be done to achieve the utility's objectives, how the work would be accomplished, how long it would take, and how much it would cost.

The project began with a thorough physical survey of the assets. Designers required precise measurements on the B6s in their respective packages to ensure that the mods planned could be prefabricated and that their installation would be possible without interference issues. A third-party contractor with ATOS (for advanced topometric optical sensor) system experience digitized the engines, associated piping, etc, to obtain this information.

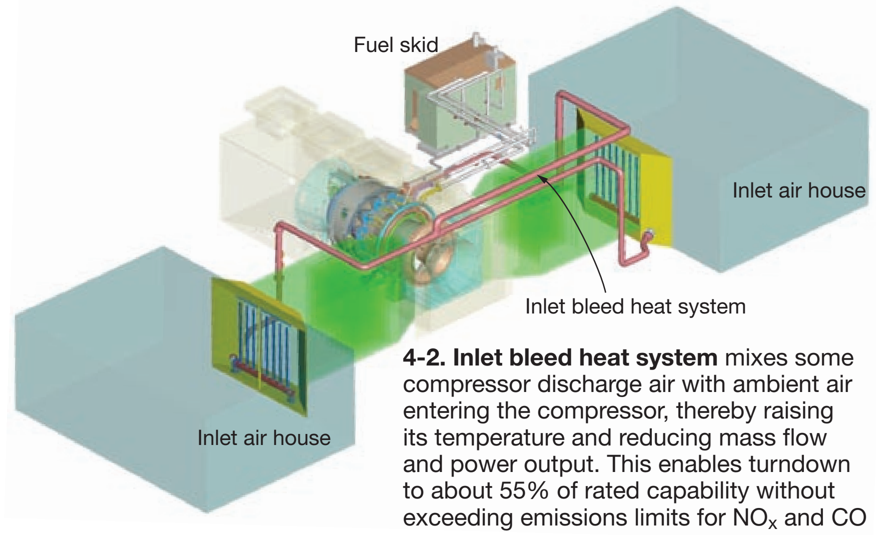
Pat Conroy, PSM's SVP of commercial operations, reminded that each project must be evaluated based on the particular machine, its fuel(s) and firing temperature, control system, auxiliaries, etc, and the specific goals the owner has in mind. A detailed engineering effort is required in virtually every case, he continued, despite past experience and successes. Reason: Equipment differs even within a given model series and designs generally are not scalable.

Other things that impact decision-making include such idiosyncrasies as the inability of old Westinghouse machines to readily accommodate an LEC-III style premix system because of limited space inside the combustor casing. The old adage, "the devil is in the details," certainly applies to re-engineering of GTs.

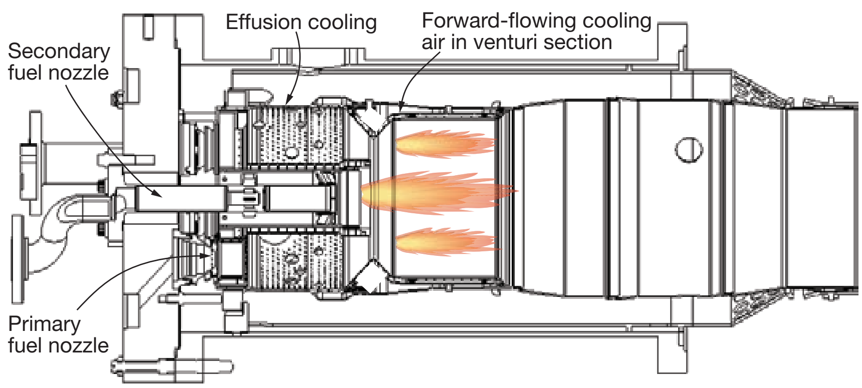
Nevada Power and PSM agreed to contract terms for the LEC-III conversion project in the first quarter of 2007. One month later, Ellis recalled, PSM ordered the longest lead-time component for each engine: the compressor/combustor case (CC case). This portion of the casing wraps the combustion system and compressor stages 7 through 17.

The new CC case arrangement would accept 12 7EA LEC-III liners and was designed to "drop into" the same space as the B6 case with its 16 smaller cans. Plus, it would have sufficient volume to allow premixing of fuel and air without need for the stub case shown in the upper half of Fig 4-1. This appendage is required on GE engines to accommodate premixing without replacing the CC case. The Clark arrangement is shown in the lower-half of the diagram.

In addition to a new CC case, the 501B6 conversion required new transition pieces, diffuser cases, and fuel skid; plus a controller to accept and operate the LEC-III combustor. To maximize turndown capability, PSM also provided an inlet bleed heat (IBH) manifold for each engine (Fig 4-2). CH2M Hill, which had been retained as the owner's engineer and construction manager for the retrofit/upgrade project, designed and installed the IBH piping system from the engine to the manifold in the air inlet.



4-2. Inlet bleed heat system mixes some compressor discharge air with ambient air entering the compressor, thereby raising its temperature and reducing mass flow and power output. This enables turndown to about 55% of rated capability without exceeding emissions limits for NO_x and CO



4-3. Maintaining a cool combustor with a minimum of air flow is critical to the success of the LEC-III design

The IBH system mixes some compressor discharge air with ambient air entering the compressor, thereby raising its temperature and reducing compressor mass flow and power output while protecting the compressor from icing under certain ambient conditions. The reduction in mass flow allows the combustor's fuel/air ratio to be held constant at lower than normal loads, thereby maintaining relatively constant NO_x emissions. This enables turndown to about 55% of rated capability. While a part-load heat-rate penalty is incurred, emissions compliance is maintained and operating flexibility is increased.

Ellis said that the LEC-III combustor is able to achieve 55% turndown while holding NO_x emissions below 5 ppm, and CO in single digits, because of its precise control of both fuel and air flow and thorough mixing of the two fluids. Maintaining a "cool" combustor is another important factor (Fig 4-3).

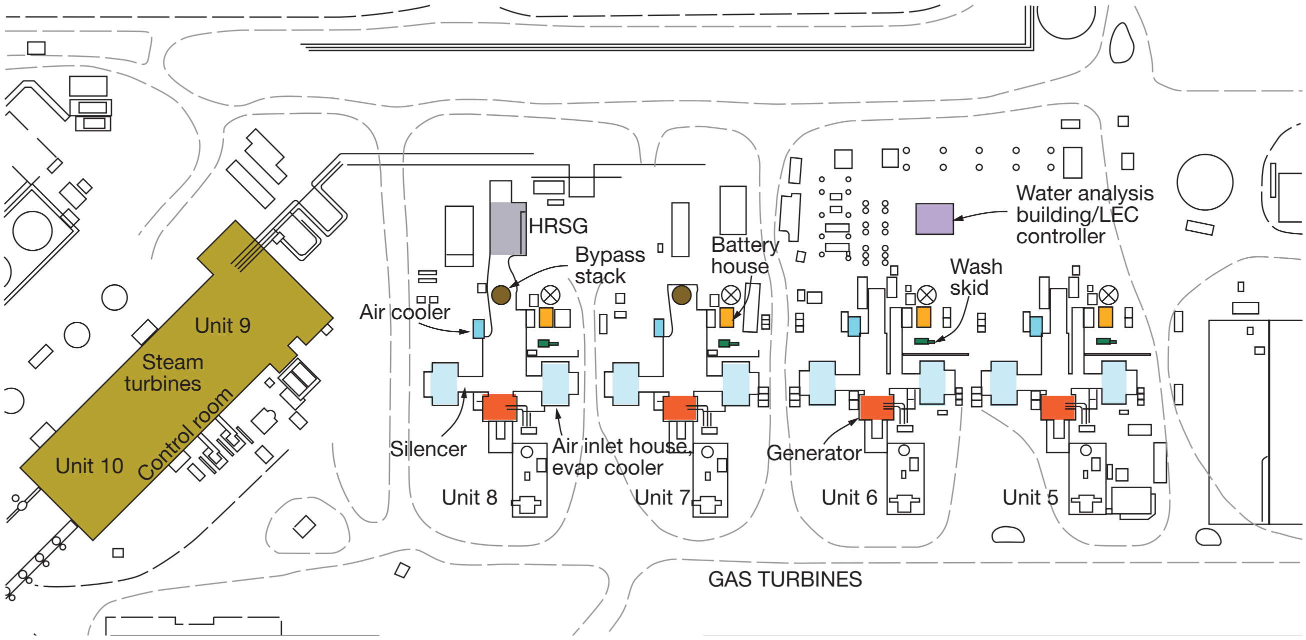
Here's how these goals are achieved:

- Gas delivery pressure to the primary fuel nozzles is optimized to enhance air and fuel premixing prior to entering the liner premix zone. Improvements to the fuel-injection design and removal of a pilot diffusion flame from the secondary fuel nozzle provides a more uniform and leaner fuel/air mixture than the OEM design. The result is a reduction of NO_x, CO, and combustion noise.
- Cooling of the combustor liner's venturi section is achieved by the LEC-III's forward flowing design which directs spent cooling air, now preheated, to the head end for mixing with the main air stream prior to combustion.

  Note that on conventional designs, the venturi cooling air flows in the same direction as the main air stream and returns near the downstream end of the combustor reaction zone. The problem with this approach is that the return air is relatively cool and when it is entrained in the hotter stabilized flame zone a significant amount of CO is not converted to CO_2.
- The precisely controlled geometry of the premixer effusion cooling holes allows designers to reduce the amount of cooling air needed to maintain combustor life. It also allows increased head-end and reaction-zone air flow to improve mixing—thereby reducing flame temperature and decreasing NO_x production.
- Tight control of both air and fuel minimizes flow variations during combustion and enables a more uniform turbine exhaust-gas temperature.

Spacing between the GTs was tight, so the optimum work plan for the LEC- III retrofit was to complete work on one GT from each power block, then do the second units for both. Fig 4-4 shows the equipment arrangement during conversion of the simple-cycle engines to combined cycles in 1993-1994. Note that Unit 8 has its HRSG installed and the bypass stack already is in place for Unit 7; work had not yet started on Units 5 and 6, which are tied to the steamer designated Unit 10.

Ellis said the first outage started in September 2008, with Units 8 and 5 recommissioned by year-end; Units 7 and 6 were operational by mid May 2009. Unit 8, the first engine retrofitted with the LEC-III, took longer to commission than the others, Ellis added. He responded to the editors' "Why?" with this explanation: Part of PSM's onsite due diligence effort in 2006 included a full characterization of engine operation, and Unit 7 was the machine instrumented to obtain performance and air-flow data. "We had to understand the B6's operational behavior and where all the air went after it entered the compressor,"



4-4. Clark site during conversion from simple to combined cycle. Note that only the HRSG for Unit 8 was installed at the time

Ellis continued, "to support the design effort."

Unit 8 components were designed as the data gathered from Unit 7 suggested. First tests showed NO_x emissions were "a bit high." Recall Conroy's words that no two engines are exactly alike. This generally is not apparent until you get to measurements requiring parts-per-million accuracy.

Ellis said "tuning" to achieve the desired NO_x emissions is relatively easy, but it adds a step to the commissioning process. It is accomplished by changing the diameter of the three liner dilution holes shown in Fig 4-1. Specifically, Ellis added, increasing orifice size reduces head-end combustor air flow and makes the air/fuel mixture more fuel-rich. This increases flame temperature and NO_x production. Smaller dilution holes restrict the amount of air allowed to bypass the combustion zone and the air/fuel mixture is "leaned-out," decreasing NO_x.

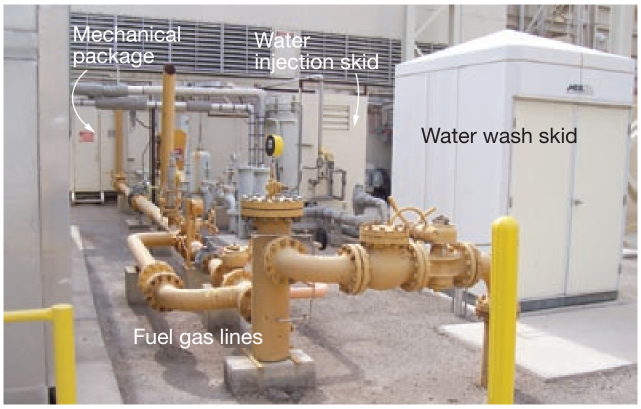
The way you make a hole smaller, Ellis said, is to first eliminate it altogether by welding in a blank and precision drilling a sharp orifice in that blank of the exact size required. The relatively quick process involves removing the combustion liners and sending them to a qualified machine shop for adjustment, and then reinstalling the parts removed. NO_x emissions from Unit 8 were exactly on target the second time around.

Assuming Unit 5, which was a couple of weeks behind the Unit 8 schedule, also would test slightly high on NO_x, PSM modified its liners before the initial fit-up. No further adjustments were necessary. When it came time to make the liners for Units 7 and 6, the same dilution holes that Units 8 and 5 ended up with were incorporated and emissions were right on target.

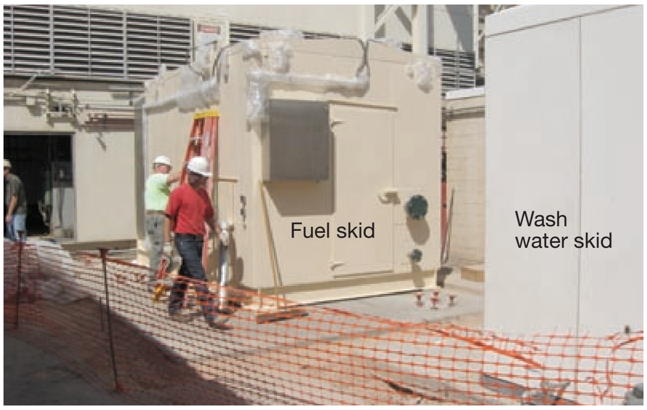
"Tuning-in" CO requires changing the diameters of different holes—ones located on the underside of the TP (refer again to Fig 4-1). While Unit 5 met the NO_x requirement on the first try, after adjusting orifice size, PSM wasn't comfortable with the CO results. Ellis said Unit 5 passed the CO test according to contract terms, but engineers thought a rapid swing in ambient temperature could push CO above the permit level at the lower operating limit (LOL, 55% of rated output). "Customer care" dictated here, he added, and the TPs were removed and their dilution holes opened up a small amount at PSM's expense.

Major steps in transitioning to DLN

To explain in general terms what's involved in converting from a diffusion combustion system to DLN,



4-5. Demolishing everything in the photo, save the water wash skid, was first step



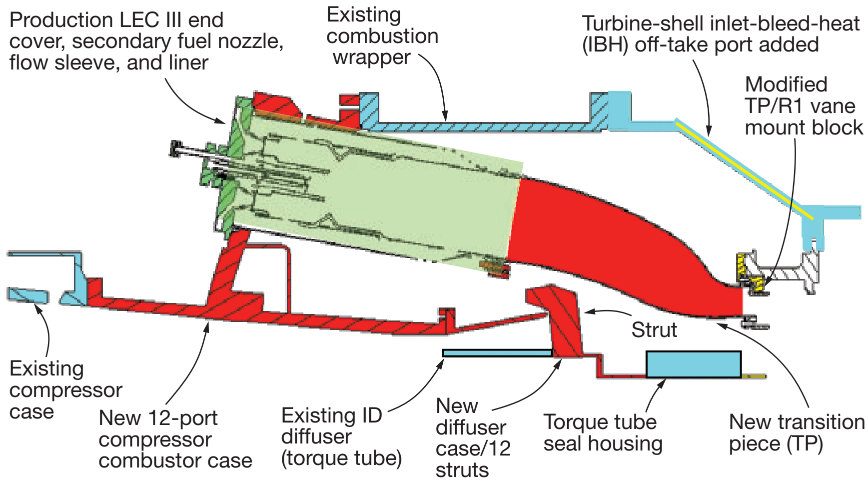
4-6. Wash water skid in Fig 5 retained its original foundation; PSM provided the new fuel skid

Ellis walked the editors through four major work packages that essentially defined the project:

- 1. Demolition and site preparation; installation of an LEC fuel skid and gas conditioning skid (one each per GT).
- 2. Conversion to LEC-III.
- 3. Inlet bleed heat.
- 4. Control-system upgrade/integration and combustion dynamics monitoring (CDMS) systems.

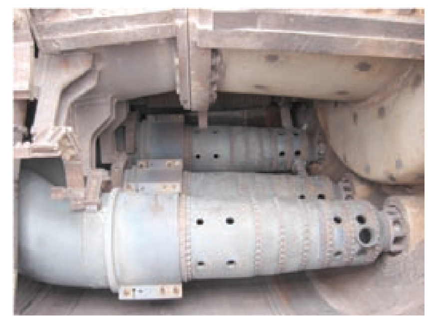
First step was to demolish the existing mechanical "cab" or "package interior," water injection skid, and fuel delivery piping—essentially everything in Fig 4-5 except for the water wash skid. The mechanical package contained the GT lube-oil system, original OEM fuel gas and oil valves, instrument air, etc.

Fig 4-6 shows the same area as in Fig 4-5 with the water wash skid in the foreground on its existing foundation and the new PSM-supplied fuel skid behind in the location of the old water injection skid. A new gas chromatograph was installed by NV Energy on the incoming natural-gas main because of the sensitivity of DLN systems to fuel composition and liquid hydrocarbons. The gas conditioning skid was supplied by NV Energy to CH2M Hill specs. All fuel-system piping external to the fuel and gas-conditioning skids was designed by CH2M Hill and installed by the general contractor.



4-7. Conversion to LEC-III required replacement of some hot-gas-path parts, modification of others; some remained as is

4-8. Insulation removed from OEM's CC case revealed end cover with gas line (large pipe) and other hardware



4-9. Wrapper case off; allowed removal of TPs and combustor baskets

Second step, conversion to LEC-III, is relatively easy to follow if you keep a mental picture of what combustion-system parts are being changed, what ones are being modified, and what parts are being retained. Fig 4-7 summarizes these activities.

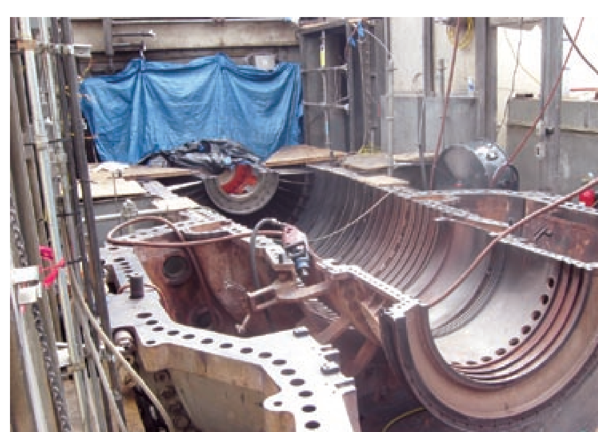
Conversion begins with the most mundane of tasks: removal of insulation. The CC case is exposed in Fig 4-8. The large flex pipe is for fuel gas; the other pipes are for water and purge air. The oil piping had been removed when the units were converted from simple- to combined-cycle service.

The upper half of the wrapper case is off in Fig 4-9 to allow removal of the OEM combustor baskets and TPs; rotor air cooling (RAC) pipe is exposed after removal of combustion components (Fig 4-10). Rotor was picked off the bearings following removal of the entire upper casing (Fig 4-11); lower-half casings are exposed in Fig 4-12.

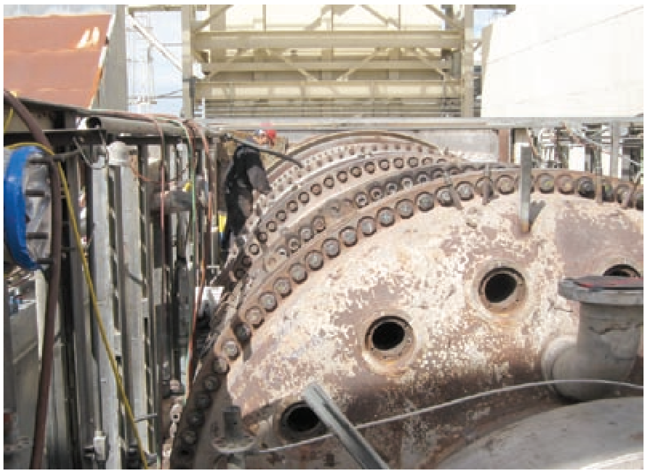
GT rotors were sent to Sulzer

4-10. Rotor air cooling pipe visible after removal of combustion components

4-11. Rotor was removed and sent to shop for refurbishment

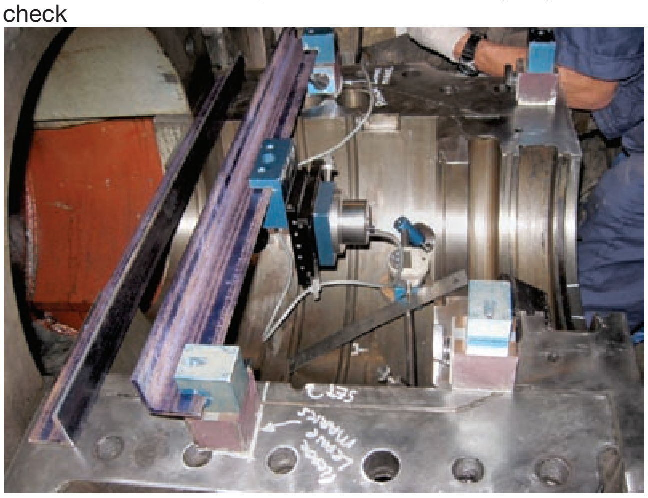


4-12. Lower-half casings exposed after rotor removal



4-13. Upper-half casings reinstalled for casing alignment check

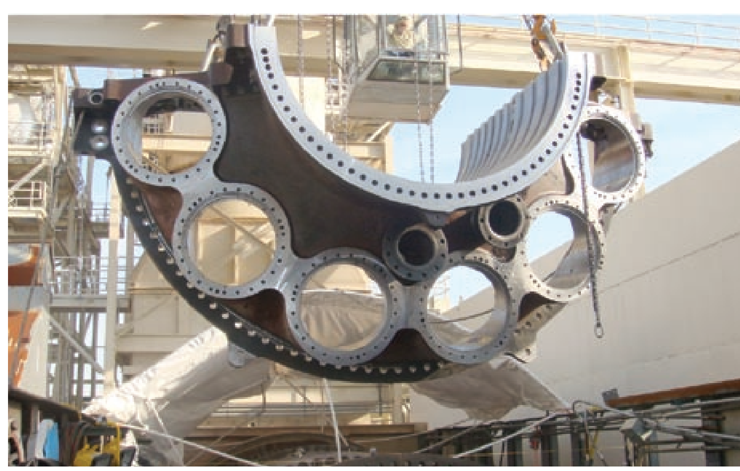
4-14. Actual casing centerline was needed to assure proper reassembly



4-15. Laser alignment tooling used bearing centers as reference

4-16. Lower half of original CC case was removed next

4-17. Millwright checks area after removal of OEM's CC case

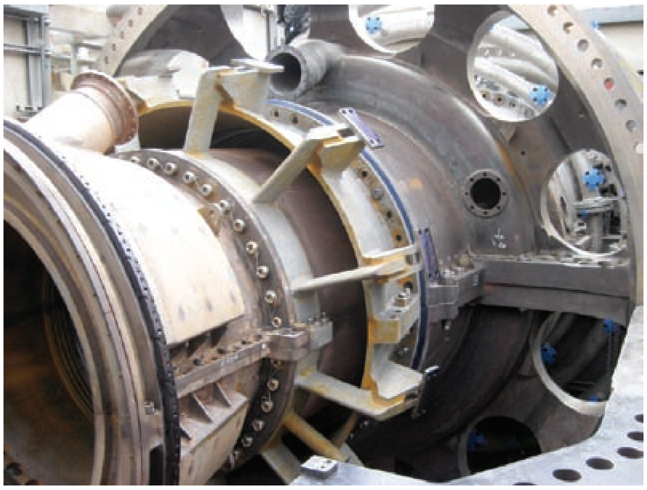


4-18. Lower half of new 12-can CC case lowered into space shown in Fig 4-17

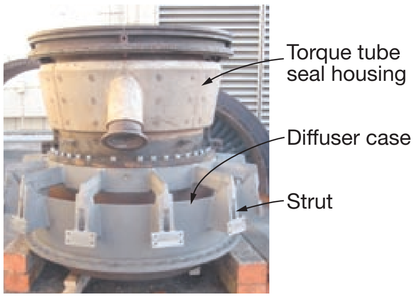
Turbo Services Houston Inc, LaPorte, Tex, for refurbishment. All were in generally excellent condition. The first-stage turbine disk for one rotor was replaced because of the large number of factored starts and operating hours experienced since commissioning.

Next, the upper-half casings were reinstalled to collect "as built" casing alignment data for the PSM field service team (Fig 4-13). The casing-centerline measurement tool is shown in Fig 4-14, the laser-alignment tool at bearing center in Fig 4-15. Ellis stressed the importance of establishing where the actual casing centerline is relative to the true centerline established by the bearings. You must have baseline measurements to properly set the new casing, he said.

Measurements complete, upper-half casings were lifted again and the lower-half of the 16-can CC case removed (Fig 4-16). Millwright stands, with the combustion wrapper at his back, in the space (Fig 4-17) where the new 12-can lower-half case will be inserted (Fig 4-18). Fig 4-19



4-19. Upper half of new CC case in position with 12-strut diffuser case in foreground

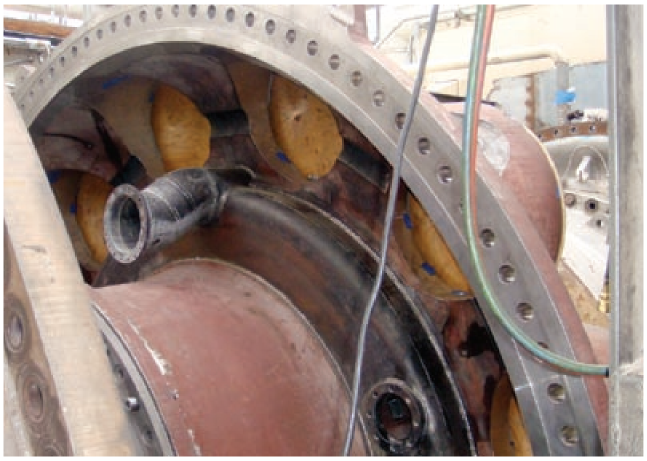


4-20. New 12-strut diffuser case is integrated with existing torque tube seal housing

4-21. Alignment rechecked with new CC case installed

4-22. Alignment true, lower casing halves are drilled and doweled to hold their position

4-23. Upper-half casings removed once again and reconditioned rotor installed



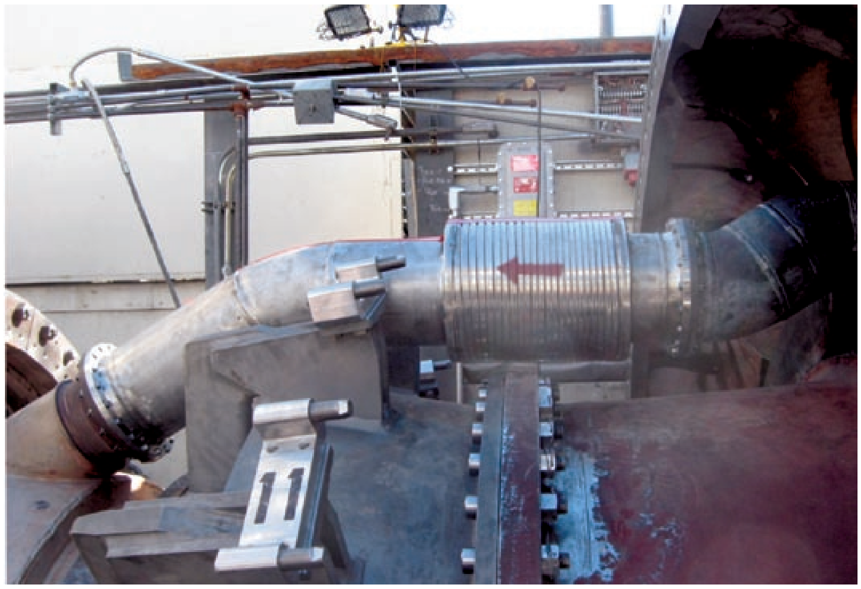
4-24. Upper-half casings replaced

shows the CC case upper half in place with the new 12-strut diffuser case in the foreground (diffuser case details are in Fig 4-20).

An alignment check with the upper-half casings installed was next to assure correct positioning of the new CC case (Fig 4-21). That step complete, lower casing halves were drilled and dowelled to lock in the final alignment (Fig 4-22), the upper-half casings removed, the refurbished rotor reinstalled (Fig 4-23), and the machine reassembled.

Ellis noted that the alignment check with the new CC case installed offered the opportunity to improve centering. Such adjustment was made on one of the Clark engines to correct a heavy rubbing condition identified at top dead center on the OEM's CC case.

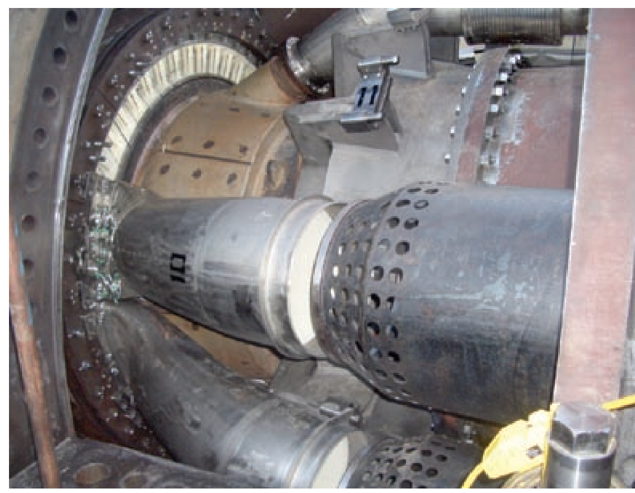
Following installation of the 12-can CC case (Fig 4-24), upgraded RAC pipes were installed. Pipe shown in Fig 4-25 delivers air cooled by the fin-fan heat exchanger to maintain proper disk-cavity temperature. PSM redesigned RAC piping to improve its flexibility and prevent cracking



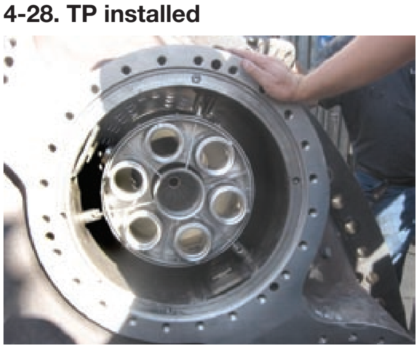
4-25. RAC pipe redesigned by PSM to minimize the likelihood of cracking

4-26, -27. Flow sleeve installed in CC case

4-28. TP installed

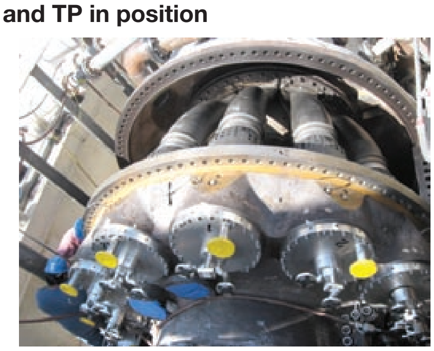


4-29. Flow sleeve and TP in position



4-30. Liner inserted in flow sleeve

4-31. Cross-fire tube in position



4-32. End covers installed

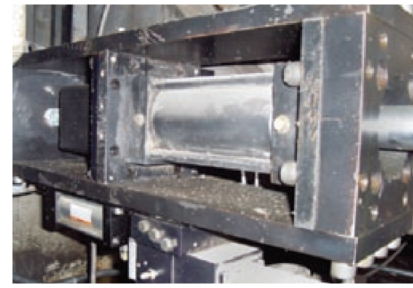
experienced by many machines in the 501 fleet.

The next series of photos records the installation sequence for LEC-III components. The lower half of Fig 4-1 is a good reference. Figs 4-26, 4-27 show the flow sleeve being installed in the CC case; TP is installed in Fig 4-28. Fig 4-29 shows the flow sleeve and TP in position; liner is inserted in flow sleeve in Fig 4-30. Cross-fire tubes are installed in Fig 4-31, end covers with fuel nozzles in Fig 4-32.

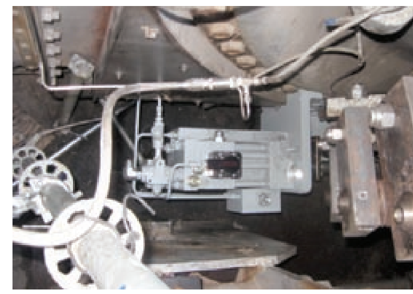
Assembled LEC-III combustion system is in Fig 4-33; the fuel manifolds, flex lines, and piping are shown in Fig 4-34. Note that the outer ring is the primary fuel manifold, middle ring the fuel transfer manifold, and the inner ring the secondary fuel manifold. Another upgrade included in the retrofit project was the replacement of pneumatic IGV (inlet guide vane) actuators (Fig 4-35) with

4-33. LEC-III in position

4-34. Fuel manifolds in foreground: Primary at top, transfer in middle, secondary at bottom



4-35. Pneumatic IGV actuator (original equipment) was removed



4-36. Hydraulic IGV actuator replaced the pneumatic one in Fig 4-35

hydraulic ones (Fig 4-36) to improve response and stroke capability.

Third step. Installation of the IBH system, looks somewhat "ho-hum" in Fig 2, but it had its challenges. IBH is provided by compressor shell air, extracted through the turbine cover (Fig 4-37). To run the piping in a manner that would not interfere with future maintenance activities dictated a circuitous route.

You can get a sense of this in the photo and the diagram: After three quick 90-deg turns the pipe angles down the side of the engine, goes through the reconfigured mechanical package at the floor level, then up, over, and across the air inlet duct before dropping down to the PSM manifolds (two per engine).

Dynamic instabilities associated with the combustion process at lean conditions have the potential to cause excess wear on combustion components. A critical function of the CDMS system installed on each of the Clark B6s is to detect harmful pressure pulsations, which are identified by sophisticated pressure transducers. The heart of the CDMS is the Alta Systems Inc (San Diego) software to analyze combustion dynamics; it triggers alarms when necessary.

A significant effort was undertaken during the LEC-III retrofit to improve air flow distribution through the engine, as well as to improve maintenance access, by more rigorous design of affiliated piping. This included a general "clean-up" of all engine piping and reconfiguration of the pipe rack.

One example: The OEM's 11th-stage extraction, which provides cooling air to turbine R3 and R4 vanes and disk cavities, had two take-off points in the lower half of the CC case. PSM changed this to one extraction in each casing half. The 11th-stage extraction also assists the sixth stage bleed in bypassing compressor air during startups and shutdowns.

Another improvement: Changed from a single- to a multi-port extraction arrangement for RAC air supply.

Fourth step, DCS modifications. The LEC-III conversion required engineers to remove fuel, water injection, and IGV logic from the existing Ovation® GT controller and to add a new controller to handle the LEC-III control logic. The four gas turbines had been converted from WDPF (Westinghouse Digital Processing Family) to Emerson Process Management's (Pittsburgh) Ovation in 2004.

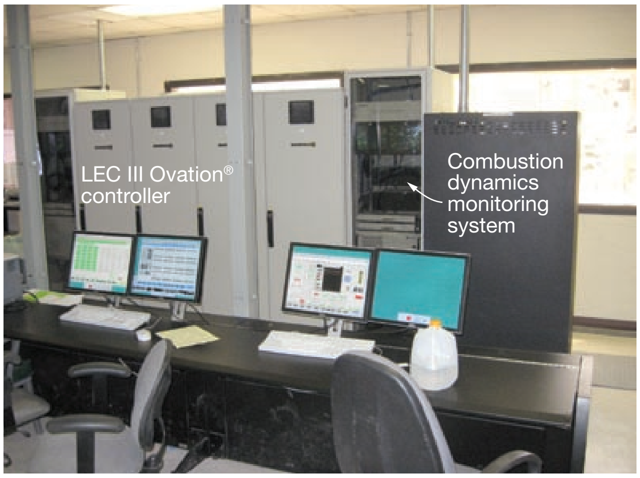
Controls work began with audits of the existing Ovation I/O cabinets to identify field instruments and wiring for demolition. Next, instrument loop drawings were created to provide termination details for new I/O, including: IBH, CDMS, gas chromatograph, new igniters and flame scanners, redundant instruments for critical measurements, and replacement of old mercury pressure switches with transmitters.

A custom algorithm was designed by Emerson specifically for PSM to monitor blade-path thermocouples (TCs) and to calculate the median blade-path temperature, which is more stable than average blade-path temperature.

The PSM controls team—Drew Franz, Walt Robinson, Jesse Sewell, and Mitch Cochran—conducted weekly conference calls with CH2M Hill and Nevada Power/NV Energy during the design phase and maintained a running action-item list. Note that Cochran is an independent controls engineer (Process Control Solutions LLC, Hattiesburg, Miss) and Ovation expert who was hired by PSM for the Clark project. Robinson

4-37. Compressor shell air is extracted to heat incoming ambient air

4-38. Water analysis building, the first 501B6 control room, is home to LEC- III controller



4-39. Work station sits in front of LEC-III controller and CDMS

also is an independent electrical/controls expert.

An onsite design review with Emerson and the utility was conducted prior to finalizing the software. A two-week factory acceptance test (FAT) of the Unit 8 software was conducted at Emerson's Riverside (Calif) offices. Following that, Emerson replicated control system for Unit 5. Controls for the remaining two units were finalized after commissioning of Unit 8.

During installation, NV Energy, PSM, and support contractors hired by CH2M Hill worked collaboratively to remove the old field instruments and wiring, install the new, and perform a complete I/O checkout. PSM provided a mechanical completion checklist, an Ovation commissioning procedure, and an Ovation settings document. All were completed and reviewed prior to first fire.

The additional Ovation controller required to accommodate the LEC-III, and the CDMS, were installed in the water analysis building (Figs 4-38, 4-39). It served as the main control room when the B6s were arranged for simple-cycle service. Benefit of this location: It is both close to the GTs and connected to the main control room in the steam-turbine building via a fiberoptic network. The utility saved a great deal of money in trenches, cable, and labor by expanding the building's utility.

How conversion to DLN impacts combined-cycle operation

Rekowski, plant director during most of the DLN conversion work, said NV Energy had to understand before work began how the upgraded engines would impact plant operations. Station staff and PSM personnel simulated, to the degree possible using an unmodified GT, the exhaust flows and temperatures expected during startup, shutdown, and partial and full-load operation when the new low-emissions combustion system was installed.

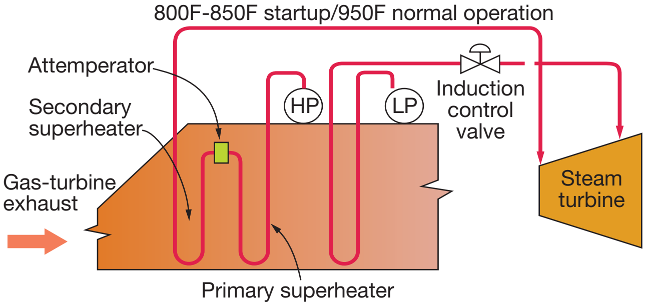
That experience and a GateCycle™ (GE Energy software) study enabled engineers to make informed decisions on the Rankine cycle hardware modifications and operational changes necessary to accommodate the LEC-III retrofit. Important to steam-turbine health was the need to maintain HP steam temperature between 800F and 850F during startup and no higher than 950F during operation.

In particular, ramp up of steam temperature during *cold* starts—when turbine metal is less than 250F—must be carefully controlled to avoid differential thermal expansion between the casing and rotor that could cause damaging rubs. Rekowski said GT exhaust temperature is higher at part load with LEC-III combustors than it was with the original diffusion burners. Impact of the hotter exhaust is to increase both HP steam temperature and LP steam production (Fig 4-40).

Replacing water-injected (for NO_x control) diffusion burners with dry combustors, Rekowski continued, reduces base-load generation by about 1% and increases heat rate by about 0.5%. But this was not of major concern to NV Energy because the Clark combined cycles now operate in load-following intermediate-duty service. Far more important was the units' ability to operate down to about 55% of rated capacity without exceeding the 5-ppm-NO_x permit requirement.

A cold start when the B6s were equipped with diffusion-flame burners, and NO_x limits were more liberal, was conducted at about 25% of rated output—or a nominal 20 MW—and was not time-limited. One hour was a goal for the units when retrofitted with the LEC III, because of the startup exemption when the unit operates above the emissions permit limit.

However, the higher exhaust temperature and flow associated with DLN firing at 50% of rated output on *cold* starts increased steam temperature and flow to levels inconsistent with those required for slow warming of the steamer to avoid the damaging rubs noted above. This despite modification of the HRSG attemperators to control the temperature of steam entering the secondary superheater to saturation plus 20 deg F by increasing spray-water flow from



4-40. Critical components in steam system are the HP superheater attemperator and the induction control valve in the LP circuit

Part of PSM's site support team takes break, leaving the following at work: Drew Franz, Jim Leahy, Mike Geyer, Esam Abu-Irshaid, and Janak Raguraman

1. Principal equipment, combined cycles, Edward W Clark Generating Station

Commercial operation: Power block 1, 1993; power block 2, 1994
Type of plant: Combined cycle (two 2 × 1 power blocks)

Key personnel
Regional director: Steve Page (acting)
Operations manager: Steve Page
Maintenance manger: Jeff Smith
Maintenance supervisor: Andy Anderson
Plant engineer: Joe Cook

Gas turbines
Manufacturer: Westinghouse Electric Corp (now Siemens Energy Inc)
Number of machines: 4
Model: 501B6
Control system: Ovation® (Emerson Process Management)
Combustion system, type: LEC III
Manufacturer: PSM
Fuel: Gas only
Water injection for NO_x control? No
Water injection for power augmentation? No
Generator, type: Air-cooled
Manufacturer: Westinghouse Electric Corp (now Siemens Energy Inc)
GSUs: Westinghouse Electric Corp

HRSGs
Manufacturer: Zurn Industries Inc (now CMI-EPTI LLC)
Control system: Ovation® (Emerson Process Management)
HRSG attemperators: Copes Vulcan, an SPX brand
Duct burner: None
Steam-turbine bypass valve/desuperheater: Copes Vulcan, an SPX brand

Water treatment
HRSG internal treatment, type: Coordinated phosphate
Chemical supplier: Nalco Co
Reverse osmosis system: GE Water & Process Technologies (onsite trailer)
Demineralizer: GE Water & Process Technologies (onsite trailer)
Wastewater treatment system, type: ZLD
Supplier: GE Water & Process Technologies (RCC brine concentrator)
Cooling-water treatment system: Nalco Co
Cooling-water chemicals: Nalco Co

Steam turbines
Manufacturer: Westinghouse Electric Corp
Number of machines: 2
Generators, type: Hydrogen-cooled
Manufacturer: Westinghouse Electric Corp (now Siemens Energy Inc)
GSUs: Trafo-Union (now Siemens AG)

Balance of plant
DCS: Ovation® (Emerson Process Management)
Condenser, type: Water-cooled
Manufacturer: Southwestern Engineering Co (now Thermal Engineering International USA Inc, a Babcock Power company)
Cooling tower, type: Wet
Manufacturer: Marley Co (now SPX Cooling Technologies Inc)
Boiler-feed pumps: Ingersoll-Rand Co
Condensate pumps: Ingersoll-Rand Co
Circulating-water pumps: Ingersoll-Rand Co

about 15 to 100 gpm. Note that there is no desuperheater in the main-steam line and it would have been too costly in both time and money to have added one.

Unable to safely cold-start the LEC III-equipped combined cycles and achieve 5 ppm NO_x within one hour, the utility asked for, and received, a special two-hour permit for cold starts. The units are able to meet the one-hour requirement on *warm* and *hot* starts. Likewise, the combined-cycle blocks are able to ramp at the pre-DLN rates without exceeding permit requirements.

Warm and hot starts proceed this way: It takes about 30 minutes to go from "flame on" to synchronization and another 20 minutes or so from synch to the premix operation required for sub-5-ppm NO_x operation. For a cold start the first step is the same. Then the GT is parked at low load—say 25%—to allow for proper warmup of the HRSG and steamer before proceeding to premix operation.

Tuning of the LP circuit presented another challenge. As mentioned earlier, the hotter exhaust associated with DLN operation (compared to diffusion combustion) increased steam production in the LP circuit for most loads that the Clark combined cycles would be dispatched at.

The LP circuit was set up in the DCS to operate at 90 psig. During trial operation with the LEC III, engineers observed that before the combined cycle reached full load, LP steam production would cause the induction control valve shown in Fig 40 to travel to the wide-open position.

When that occurred, the DCS signaled the valve to close. Reason: A minimum pressure drop across the valve was built into control logic to protect against reverse flow—that is, to prevent the induction line from becoming an extraction line. Initially, plant staff thought to maintain the pressure drop by bypassing some LP steam to the condenser. Planned unit operation would only require this periodically and the efficiency penalty would not be significant on an annual basis.

But careful re-review of system drawings revealed that the LP circuit was designed to operate at from 90 to 108 psig. Issue was resolved by changing control logic to maintain a minimum delta p and allow the pressure to ride up above 90 psig; it will not reach the condenser dump-valve set point of 108 psig under any normal operating scenario.

4-41. Site preparation for the 12 SwiftPacs in the early stages shows trenches to house the underground electrical distribution system and piping networks

FT8s provide up to 618 MW (peak day) in 10 minutes

The world's largest SwiftPac project officially began in 2006 with its approval by the Public Utilities Commission of Nevada. CH2M Hill was selected to engineer, procure, and construct the peaking facility and received a limited notice to proceed in January 2007; gas turbines were ordered the same month.

To make room for the 12 units, which are arranged in three power blocks of nominal 200 MW each, the original gas-fired steam units installed at the station were demolished. Units 1, 2, and 3 had been retired in 2005. First equipment was delivered in September 2007 and the first SwiftPac was commercial before the end of July 2008; project was completed by the end of February 2009.

CH2M Hill's project manager, Bob Forsthoffer, said that after the steam units were removed and the site prepared he had "a big field" to accommodate the peakers. Site layout was a collaborative effort between the EPC contractor and the utility to assure (1) access to underground piping and electrical and control cable, (2) ease of maintenance, and (3) orientation of engine inlets and stacks to minimize the possibility of one engine's compressor sucking in another engine's exhaust.

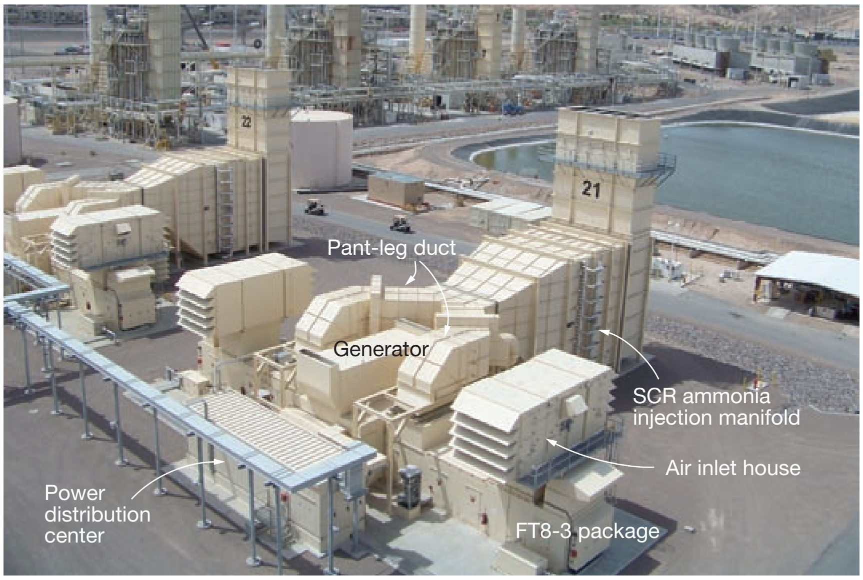
Forsthoffer recalled that the electrical work for the Clark peakers was particularly challenging. One reason: The very tight market for electricians and electrical equipment during the construction boom. Las Vegas was the fastest growing city in America at the time.

Another reason: Underground electrical systems had to be installed at the front end of the project for construction to proceed. This was a major undertaking (Fig 4-41). The two 300-hp tempering-air fans and other auxiliaries required to support each SwiftPac dictated installation of more than 23 miles of 4-in.-diam PVC-insulated 480-V cable. There also was a high volume of bus work; each block was served by one GSU (generator step-up transformer).

The electrical equipment supply chain was so constrained, the preferred supplier for the power distribution centers required on each SwiftPac could not bid on the project. However, that turned out to be a non-problem, Forsthoffer said, because the winning bidder, Tesla Power & Automation LP, Houston, proved to be at least equal to any other supplier in the industry.

The underground electrical work was done by a local contractor on a time-and- materials/self-perform basis. This went so well, Forsthoffer said, aboveground electrical work was done the same way. Foundation work also was conducted on a self-directed basis, and by the same firm that did the Allen 4 project (see Section 7, Arrow Canyon Complex). P&W provided detailed foundation specifications that included locations of grounds, etc.

SwiftPacs can be assembled quickly, Forsthoffer continued. They fit on one 3-ft-thick foundation pad



4-42. SwiftPacs are installed in a compact arrangement on a 3-ft-thick concrete pad. A savvy crew can complete installation of one unit in three weeks or less

(Fig 4-42) and P&W supplied all the interconnecting piping and wiring that goes on the mat. No cooling water is required; a fin-fan cooler serves the lube-oil system.

Hook-ups only were required for demineralized water, fire water, and ammonia. Demin is used for inlet fogging and for injection into the engine to reduce NO_x emissions; ammonia is the reagent for the selective catalytic reduction (SCR) system to bring NO_x emissions within permit limits.

Follow the SwiftPac erection sequence in Figs 4-43 through 4-46: Engine package arrives (4-43); control cab is lowered into position (4-44) with SCR framing at right; unit takes shape in 4-45 and can be completely installed in three weeks according to P&W literature (4-46). The control cab was prewired and factory-tested.

Bala Chitoor, P&W's project manager for the Clark SwiftPacs said he was responsible for timely delivery of power-island equipment and for onsite technical support. Schedule was very aggressive, Chitoor continued, especially given that environmental requirements were among the most challenging in the nation. Contract specified installation, testing, commissioning, and compliance testing of all 12 units within 16 months.

NO_x emissions are limited to 5 ppm, CO to 2 ppm, and ammonia slip to 5 ppm. Noise criteria are similarly stringent at 85 dBA 3 ft from the equipment and 5 ft above grade—across the range of 16 Hz to the highest audible frequency. Residences are within about 100 yards of the plant property line. It wasn't always that way. When the first Clark steam units were installed, the plant was remote; today it's essentially in the "middle of town."

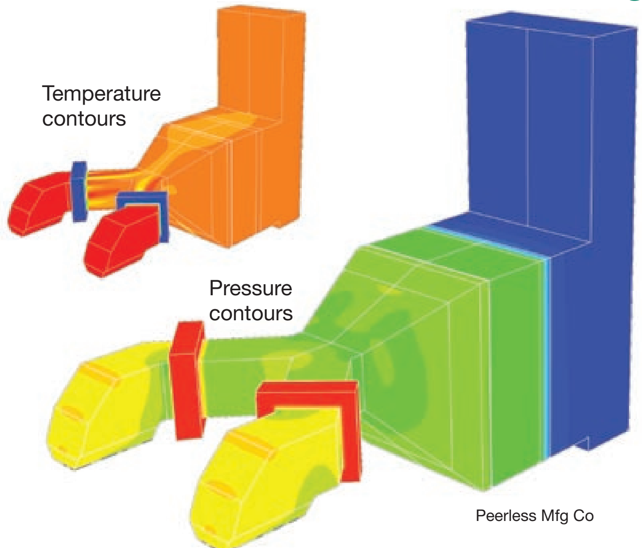
Peerless Mfg Co, Dallas, was P&W's subcontractor for environmental systems. Tim Shippy of Peerless admitted, "Noise was a par-

4-43. SwiftPacs are delivered in modules ready for installation. Here a gas-turbine package is brought to its pad

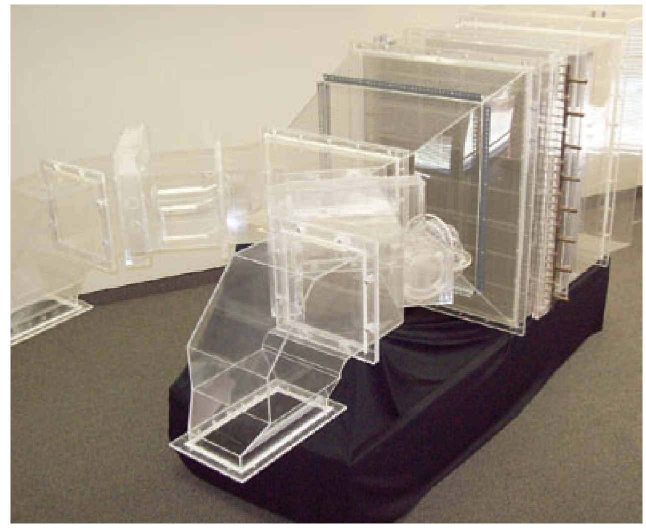
4-44. Control cab is lowered into position

4-45. Erection progresses quickly. Major components and most ductwork are in place

4-46. Nearly complete. The "heavy" work complete, all that remains is painting



4-47. CFD modeling of exhaust gas flow is essential to assure meeting emissions limits for NO_x and CO



4-48. Plexiglas® model confirmed that CFD analysis was correct

ticular challenge." He said casing radiated noise and stack exit noise were the two main sources. P&W hired an independent expert to guide acoustic design and Peerless followed his recommendations, including:

- Extending stack silencers to the tops of the stacks.
- Soundproofing intakes for tempering-air fans.
- Using heavy-gauge steel for ductwork.
- Peerless' scope of supply for the CO, VOC, and NO_x emissions-control package included the following:
- Expansion joints at turbine outlets.
- Exhaust system from the GT outlets through the stack.
- Ammonia flow control unit and injection grid. Aqueous ammonia is vaporized and injected downstream of the CO grid.
- Tempering/purge air skid. It pipes ambient air into the exhaust ductwork just ahead of the pant-leg and from underneath.
- Rectangular 60-ft-high stacks (equivalent to an 18-ft-diam conventional stack).

When faced with designing to meet emissions limits for NO_x and CO in the low single digits, Shippy said, you really have to do your homework and can take nothing for granted. It is important to get good distribution of exhaust gas flow across the entire duct cross section to assure optimum contact with catalyst. Likewise, the ammonia injection grid and spray nozzles must provide even distribution of reagent in the flow stream.

Peerless engineers left no questions unanswered with extensive CFD (computational fluid dynamics) analysis (Fig 4-47) and validation of their proposed design with Plexiglas® model (Fig 4-48). Catalyst was supplied through Peerless: CO from BASF Catalysts LLC, Iselin, NJ; SCR from Cormetech Inc, Durham, NC.

2. Principal equipment, FT8 peakers, Edward W Clark Generating Station

Commercial operation: November 2008-February 2009
EPC contractor: CH2M Hill
Type of plant: Simple cycle

Key personnel

Regional director (acting): Steve Page
Operations manager: Steve Page
Maintenance manger: Jeff Smith
Maintenance supervisor: Andy Anderson
Plant engineer: Joe Cook

Gas turbines

Manufacturer: Pratt & Whitney Power Systems
Number of machines: 24 (two engines per SwiftPac®)
Model: FT8-3
Control system: Ovation® (Emerson Process Management)
Fuel: Gas only
Water injection for NO_x control? Yes
Water injection for power augmentation? No
Generators, type: Air-cooled
Manufacturer: Brush Turbogenerators Inc
GSUs (one per block of four SwiftPacs): Siemens AG
Inlet-air cooling system, type: Fogging
Manufacturer: Mee Industries Inc

Heart of the SwiftPac is a double-ended generator driven by two FT8 engines with nine combustors each (refer back to Fig 4-42). The natural-gas-fired, water-injected, diffusion-flame Model FT8-3 was specified for Clark rather than the FT8-2 DLN version, Chitoor said, because it offers a higher output and lower life-cycle cost (Figs 4-49, 4-50). He added that FT8 fleet starting reliability exceeds 97%; availability, 95%.

Exhaust exits the FT8-3 with about 38 ppm NO_x; the SCR lowers that to the 5 ppm permit limit. SwiftPac rated output is 61,196 kW at 59F and sea level. Simple-cycle heat rate at those conditions is 9266 Btu/kWh, which translates to 36.8% efficiency.

The GT package includes a shippable engine enclosure containing the gas generator, power turbine, exhaust collector box, inlet plenum, and lube-oil system. The Clark units are equipped with inlet foggers and an off-line water wash system (one portable cart-mounted system for each power block).

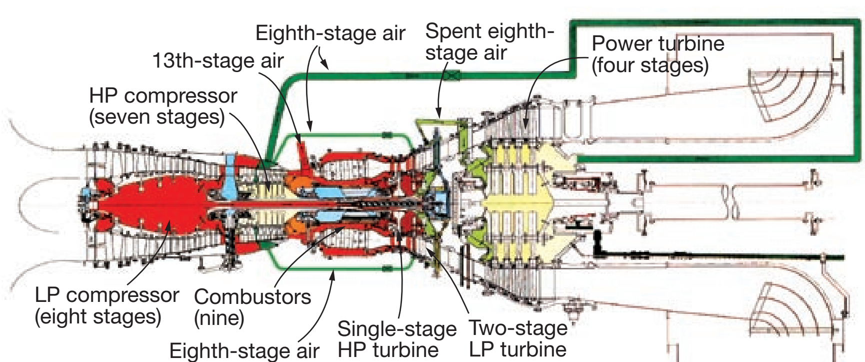
Highlights of the Clark GT package specification include the following:

- Fin-fan lube-oil cooler designed for operation at 120F ambient.
- Two ac and one dc lube-oil pumps per turbine.
- Air-to-air exchanger for engine cooling designed for 120F ambient.
- Two-stage air-inlet filtration system—prefilter and second stage with high-efficiency media. Capture efficiency of 99.7% for all particles 5 microns or larger; 95% for all particles 2 microns or larger—under all environmental conditions.

- Air-inlet system designed to withstand an internal vacuum of 10 in. H_2O without leaking, buckling, or deforming; inlet silencer of stainless-steel construction.
- One inlet fogging skid per package to accommodate ambient air at 117F, 10% RH.
- Recommended gas pressure, 445 psig. Engine burns approximately 4700 scfm at rated load.
- Injection water for NO_x control, 35 gpm per GT at 105 psig.
- Typical offline water wash uses 300 gal per GT (at 35 gpm max dispensed at 35 to 105 psig).
- Fire detection and protection systems.
- Start up in less than 10 minutes from cold condition to full load.
- Seismic-type vibration sensors for machine protection.
- Bently Nevada 3500 series (or approved equal) non-contacting radial bearing vibration probes for monitoring only.
- Electric-motor-driven hydraulic starting system.

The double-ended generators for the SwiftPacs were supplied by Brush Turbogenerators Inc, Houston. In addition to the DAX generators, Brush's scope of supply to P&W included its Prismic® Model A32 excitation controllers and the lube-oil system. CCJ

4-49. FT8-3 is unwrapped and prepared for installation



4-50. Key components of an FT8-3 are visible in cutaway drawing. Eighth-stage air is routed to a fin-fan heat exchanger and then returned to cool bearing housing

Clark Station's senior team (l to r): Anthony Giannantonio, senior environmental scientist; Steve Page, operations manager and acting plant director; Jeff Smith, maintenance manager; Andy Anderson, maintenance supervisor; Christine Hinshaw, senior advisor of safety and compliance; Joe Cook, plant engineer