Part B – Project Description

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B. PROJECT DESCRIPTION

B.1 GENERAL DESCRIPTION

Connacher Oil and Gas Limited (Connacher) is currently operating the Great Divide SAGD Project and is in the final stages of construction for the Algar SAGD Facility (Figure A.1-2), which is expected to be fully operational in the spring of 2010. Both facilities have a design capacity of approximately 1600 m^3/day (10,000 barrels/day) of bitumen. Connacher plans to expand the capacity of the lease operations in the Great Divide area, which captures both the Great Divide and Algar Project, by an additional 3,800 m^3/day (24,000 barrels/day) of bitumen production. The total production of the Great Divide Lease area will increase to approximately 7,000 m^3/day (44,000 barrels/day).

The Great Divide Project consists of the following components, central processing facility (CPF), access road and infrastructure, two well pads with 17 well pairs, water source wells, operators camp and air strip with a total disturbance footprint of 99.9 ha. The Algar Project consists of the following components, central processing facility (CPF), access road and infrastructure, three well pads with 17 well pairs, water source wells and a permanent operator's camp with a total disturbance of 117.7 ha. The combined disturbance for both projects is 217.7 ha. Both of these projects are being considered as part of the baseline conditions for the Great Divide SAGD Expansion Project.

The Great Divide SAGD Expansion Project will involve expanding the Algar CPF from the current 1600 m^3/day (10,000 barrels/day) by an additional 3,800 m^3/day (24,000 barrels/day). The Great Divide CPF will not be altered as part of the expansion. With the increased production capacity of the CPF, there is need for additional bitumen supply for the Project. This application provides the details for the additional bitumen supply over three phases for the life of the Project which is estimated to be 25 years. Connacher has a high level of confidence in developing Phase 1 of the Project as presented in this application. The confidence level in the subsequent phases is less than Phase 1. The total estimated disturbance for all three phases of the Project is 520.8 ha. While Connacher expects this will evolve and change as development progresses, this is the area that the assessment of the Project impacts was based.

Connacher plans to conduct additional exploration activities on the lease area to identify and better define the bitumen resource. For example, recent exploration activities during the 2009/10 winter have identified additional resources west of Highway 63 and north of the Great Divide Project. As additional resources are better delineated, development plans will be altered to include them into the Project. The future implications could mean expanded production or increased Project life.

Details of the proposed development are described further in this section.

B.1.1 Phase 1 Overview

Connacher plans to employ the same bitumen extracting and processing technology in all phases of the Project as are currently being used for the Great Divide and Algar Projects. The expansion will employ "more of the same" technology. The existing infrastructure, both internal and external, will be used and expanded as required. Phase 1 of the Project will consist of the following components (Figure B.1.1-1):

- expansion of the CPF by 3,800 m^3/day which will occur entirely within the existing Algar CPF footprint;
- additional lay down area adjacent to the CPF will be required;
- additional area for remote sumps will be required;
- nine well pads with 59 well pairs;
- access roads and infrastructure, including borrow pits;

- total estimated footprint required is 145.5 ha.

B.1.2 Phase 2 Overview

Phase 2 of the Project will provide replacement bitumen supply as the production from Phase 1 well pairs declines. The replacement well pads and well pairs are required to maintain the full production of 7,000 m^3/day (44,000 barrels/day). Significant changes to the CPF are not contemplated with the phase of development. Phase 2 of the Project will consist of the following components (Figure B.1.1-2):

- twelve well pads with 73 well pairs;
- access roads and infrastructure, including borrow pits;
- additional area for remote sumps;
  - total estimated footprint required is 189.9 ha.

B.1.3 Phase 3 Overview

Phase 3 of the Project will provide replacement bitumen supply as the production from Phase 2 well pairs declines. The replacement well pads and well pairs are required to maintain the full production of 7,000 m^3/day (44,000 barrels/day). Significant changes to the CPF are not contemplated with the phase of development. Phase 3 of the Project will consist of the following components (Figure B.1.1-3):

- nineteen well pads with 83 well pairs;
- access roads and infrastructure, including borrow pits;
- additional area for remote sumps;
  - total estimated footprint required is 186.3 ha.

B.2 GEOLOGY AND RESERVES

This section evaluates the geology and resources within the Project area. The geological assessment carried out for the Project is identical to the processes used by Connacher for the Pod One and the Algar SAGD Projects, which received ERCB approved in July 2006 and October 2008 respectively.

B.2.1 Geological Data and Control

Connacher's oil sands leases composed of rights below the Top of the Viking to Base of the Woodbend within the Project Area are:

- No. 0747404010456 ("OSL #56") covers 3,074 ha (7,591 acres) of land located in Sections 27-34, Twp 81 Rge 11 W4M and Sections 3-6, Twp 82 Rge 11 W4M;
- No. 0747404010459 ("OSL #59") covers 5,120 ha (12,652 acres) of land located in Sections 7-9, 17-20, 29-32, Twp 82 Rge 11 W4M and Sections 11-14, 23-26, 35-36, Twp 82 Rge 12 W4M;
- No. 0747404010460 ("OSL #60") covers 4,608 ha (11,387 acres) of land located in Sections 8-10, 15-17, 20-22, 27-29, 32-34,Twp 82 Rge 12 W4M and Sections 2-4, Twp 83 Rge 12 W4M;
- No. 0747405070553 ("OSL #53") covers 256 ha (640 acres) of land located in Section 9, Twp 83 Rge 12 W4M;
- No. 0747405070554 ("OSL #54") covers 256 ha (640 acres) of land located in Section 10, Twp 83 Rge 12 W4M;
- No. 0747407010531 ("OSL #31") covers 256 ha (640 acres) of land located in Section 11, Twp 83 Rge 12 W4M;
- No. 0747405070555 ("OSL #55") covers 256 ha (640 acres) of land located in Section 14, Twp 83 Rge 12 W4M;

- No. 0747405070556 (“OSL #56”) covers 256 ha (640 acres) of land located in Section 15, Twp 83 Rge 12 W4M;
- No. 0747406010664 (“OSL #64”) covers 256 ha (640 acres) of land located in Section 23, Twp 83 Rge 12 W4M;
- No. 0747406010665 (“OSL #65”) covers 256 ha (640 acres) of land located in Section 26, Twp 83 Rge 12 W4M; and
- No. 0747406010666 (“OSL #66”) covers 256 ha (640 acres) of land located in Section 35, Twp 83 Rge 12 W4M.

Since 2005, Connacher has carried out six 3D seismic surveys totalling 165 square kilometres and drilled 246 exploratory wells within the 58 section Project area. The existing 3D seismic coverage, the location of core holes, plant locations of both Great Divide and Algar and the Project Area outline are shown on Figure B.2.1-1.

The resource is well defined with exploratory drill holes and 3D seismic. The high resolution 3D seismic programs were carried out between 2005 and 2008 and the merged dataset covers the majority of the Project Area. Connacher’s exploratory drill program (246 wells) and industry drilling (35 wells) has delineated approximately 30% of the acreage based on 40 acre well spacing. The drilling has identified B2 McMurray Channels (ERCB – McMurray Channel) and McMurray C Channels trending in a SW/NE direction through the oil sand leases (Figure B.2.1-2).

B.2.1.1 Exploration Drill Hole Program Information

To date, Connacher has drilled the following oil sands exploration wells in the project area:

- 11 oil sands exploration holes in 2004; 11 cored
- 12 oil sands exploration holes in 2005; 12 cored
- 26 oil sands exploration holes in 2006; 22 cored
- 75 oil sands exploration holes in 2007; 34 cored
- 99 oil sands exploration holes in 2008; 47 cored
- 23 oil sands exploration holes in 2009; 17 cored
- 68 oil sands exploration holes in 2010; 30 cored

In addition, there were 35 pre-existing industry wells in the Project Area that were drilled for shallow gas targets or as deep exploration stratagraphic tests. Continuous McMurray core was taken in 173 (55%) wells. The core samples have been analyzed for bitumen saturation, porosity and permeability. A detailed “facies” description is recorded for each cored well and effective porosity is calculated using the density log corrected for shale volume. The oil saturation calculation from the log data is calibrated to Dean-Stark analysis data from the cores to cross verify results. All log, core and seismic data are combined into a resource model capable of characterizing bitumen distribution and reserves.

B.2.1.2 Seismic Survey Program Information

In addition to the exploration drilling described above, Connacher has almost completely covered the oil sand leases with 3D seismic programs shot between 2005 and 2008. The project area had 35 pre-existing wells and subsequent oil sands wells were located and drilled with the help of the 3D seismic interpretation. The detailed seismic was shot with an 100 m by 80 m shot and receiver grid which yielded 20 by 20 m bins in the subsurface. The seismic data:

- responds well and helps identify gas filled sands and “bright spots” in the Upper Mannville formations;
- helps distinguish interfaces in the McMurray Formation; and
- gives the interpreter an excellent reflection of the McMurray contact with the basement carbonates of the Beaverhill Lake Formation of the Devonian Woodbend Group.

The interpretation of these seismic reflections lead to a high degree of confidence in the mapping especially the sand thickness; however, cores and logs are required to provide quality and facies information.

B.2.1.3 Results of Exploration Program Information

The exploration program described above resulted in the identification of several pods of SAGD bitumen resource within the Project Area. There is still significant acreage within the Project Area that is not fully tested and is a target for future exploration.

B.2.2 Regional Geology

Connacher evaluated the regional geology for the Project in a study area defined by Townships 81 to 83 and Ranges 11 to 13 W4M.

B.2.2.1 Regional Stratigraphy

Figure B.2.2-1 describes the general stratigraphy in the area of the Project Area. The bitumen resource is located in the McMurray Formation, which is the oldest formation within the Mannville Group of the Lower Cretaceous Period.

In northeastern Alberta the Mannville Group is composed primarily of unconsolidated sedimentary rocks that are divided into three formations. From oldest to youngest, these formations are the McMurray Formation, the Clearwater Formation and the Grand Rapids Formation.

The McMurray Formation lies unconformably on the carbonates of the Woodbend Group. This unconformity was formed during a period of subaerial exposure and erosion and it was this erosional sequence that initially influenced the deposition of the McMurray. The prospective McMurray sands in this area are estuarine channel in nature while the upper sediments of the McMurray are deposited in marginal marine environments. Estuarine environments typically show numerous depositional sequences due to channel migration, storm activity and erosional down cutting. The repeated reworking of the sediments can result in stacked, thick, high-quality sand reservoirs which are usually filled with bitumen resources.

B.2.2.2 Woodbend Group

The Woodbend Group consists of dolomitized fossiliferous limestones and argillaceous limey muds of the Upper Devonian Period. Figure B.2.2-2 shows the gently dipping structure of the Woodbend Group in regional context. The limestone or limey muds do not contain bitumen resources in this area and are considered to be a barrier to fluid flow.

B.2.2.3 McMurray Formation

In the Project Area the McMurray Formation ranges in thickness from 40 to 70 m and is composed of sandstones, shales and mudstones. The overall thickness of the McMurray Formation is controlled by the erosional topography on the Woodbend surface. Figure B.2.2-3 shows a structure map of the McMurray Formation in the region and Figure B.2.2-4 the McMurray Formation isopach.

In the Project Area, the sediments of the McMurray Formation were deposited in an estuarine environment where tides regularly moved sands up and down tributary channels leaving stacked channel sands and shale plugs over a vast area. In contrast, the upper McMurray transgressive deposits were laid down in a marginal marine environment resulting in several fining upward sequences of sand and shale. The resultant variation in thickness of the McMurray formation is strongly influenced by the topography on the eroded Woodbend Group.

The "*EUB – Athabasca Wabiskaw–McMurray Regional Geological Study (2003)*" has standardized the nomenclature of several units in the McMurray Formation. These depositional units named from bottom to top are McMurray C Channel, McMurray B2 Sequence (ERCB McMurray Channel), McMurray B1 Sequence, McMurray A2 Sequence and McMurray A1 Sequence.

The McMurray C Channel and B2 Channel (McMurray Channel) sequences are 20 to 30 m thick and consist of fining upwards sequences of sand and shale. The sequences often include massive cross bedded sands overlain by interbedded sands and shales capped by laminated mudstones. These tight mudstones are considered a barrier to fluid flow and act as a caprock (Section B.3.5). The massive oil sands in the basal portions of the McMurray C Channel have created a tremendous reservoir for the oil as it migrated through the area. Occasionally these thick sequences contain shale clast breccias, slump blocks, shale lenses and scattered rip-up clasts that tend to be laterally discontinuous. In the upper part of the sequence zones there are bioturbated zones, rhythmically interbedded sand and shale with moderate to high dip angles know as inclined heterolithic stratification (IHS). Overall the upper B2 sequence tends to have shaly IHS as the channels completely fill with muddy sediments.

The Upper McMurray (B1, A2 and A1 McMurray Sequences) consist of extensive stacked coarsening upward marginal marine sequences and contain little potential for SAGD recoverable resources in the Project Area due to their thickness of less than 5 m.

B.2.2.4 Clearwater Formation

The Wabiskaw member is the lower most sequence of the Clearwater Formation. The Wabiskaw dips regionally to the southwest as seen in Figure B.2.2-5 (Wabiskaw Structure) at approximately 290 m subsea in the project area. The Wabiskaw member is typically 10 to 12 m thick and consists of cleaning upward transgressive marine silty sands.

The Upper Clearwater Formation overlays the Wabiskaw with a thick 40 m shale sequence, overlain by an 18 m shaly sand sequence capped with 10 m shale at the top of the formation.

B.2.2.5 Grand Rapids Formation

The Grand Rapids Formation comprises an upper and lower member. The Lower Grand Rapids member dips gently to the southwest (Figure B.2.2-6, Lower Grand Rapids Structure), averages 44 m in thickness with a 25 m coarsening upward porous sand interval that is water wet in the project area (Figure B.2.2-7, Lower Grand Rapids Isopach). The Upper Grand Rapids Member is typically 45 to 50 m thick and consists of stacked coarsening upward sand cycles separated by impermeable thin marine shale. These sands are water wet and can have thin gas accumulations in the project area. Structure of the Upper Grand Rapids Formation is shown in Figure B.2.2-8 (Upper Grand Rapids Structure).

B.2.2.6 Joli Fou Formation

Tight marine shale of the Cretaceous Joli Fou Formation overlies the Grand Rapids Formation. The Joli Fou is truncated at the unconformable contact with unconsolidated Quaternary glacial drift. The LaBiche is occasionally present as the uppermost bedrock surface.

B.2.2.7 Quaternary

The surface glacial deposits are comprised of gravel, sand, silt and mud and average about 100 m thick in the Project Area and are always placed behind surface casing when drilling exploratory core holes or SAGD well pairs. The elevation of the Quaternary ranges from 520 to 600 asl and is approximately 120 to 160 m thick (Figure B.2.2-9, Quaternary Structure).

B.2.3 Project Area Geology

B.2.3.1 Site Stratigraphy

The well log for core hole 100/04-19-082-11-W4M (Figure B.2.3-1) is typical of the stratigraphy for the Project. Measurements of bitumen, water saturation and porosity were made on the core from this drill hole. There was very good agreement between the log and core data as defined through petrophysical analysis.

The Project Area is divided into several distinct sub areas or "Pods". These Pods are separate accumulations of oil sands with identified thickness and quality (Figure B.2.3-2). Four cross-sections that illustrate the lithological differences between each Pod are shown on Figures B.2.3-3 (Section A-A' North-South I) Figure B.2.3-4 (Section B – B' North-South II), Figure B.2.3-5 (C-C' East-West I), and Figure B.2.3-6 (D-D' East-West II).

B.2.3.2 Log and Core Characteristics

Of the wells that were drilled and logged, approximately 58% were cored. Core analysis included measurements of the bitumen saturation, water saturations and porosity. There was good agreement between the core data results and the down-hole conventional log data. This confirmation was further used to perform log analysis and interpretation on wells that were not cored. Figure B.2.3-7 shows an example of the log analysis work for Well 1AA/08-30-082-11-W4/00 and Table B.2.3.1 shows the excellent interpreted log to core comparison for surrounding wells in the Algar area.

Table B.2.3.1 Comparison of Log to Core

Well	Area	ZN_ TOP	ZN_ BOT	Log Net Pay	Core Net Pay	Log Bitumen Wt %	Core Bitumen Wt %
1AA083008211W400	Algar North	455.0	500.0	25.4	26.7	11.9	12.0
1AA023008211W400	Algar North	460.5	505.0	24.8	22.9	12.3	13.4
1AA163008211W400	Algar North	459.0	504.0	19.2	21.2	12.1	12.3
1AA132908211W400	Algar North	457.0	503.0	18.7	21.2	10.8	11.3
1AA013108211W400	Algar North	462.0	505.0	13.6	14.1	11.1	10.5
1AA041908211W400	Algar North	469.0	515.5	27.8	28.5	13.5	14.0
1AA043208211W400	Algar North	454.5	500.0	22.1	20.3	11.5	11.5
1AA052908211W400	Algar North	493.0	502.5	8.6	8.3	12.0	13.4
1AA062908211W400	North/South	453.0	495.0	4.7	1.7	9.9	12.0

B.2.3.3 Seismic Characterization of the McMurray Formation

Connacher recorded detailed high frequency 3D seismic programs over the majority of the Project Area between 2005 and 2008 (Figure B.2.1-1). By utilizing state-of-the-art seismic recording equipment, tight source and receiver line spacing and a one millisecond sample interval, Connacher obtained excellent subsurface spatial images and very high frequencies which helped to successfully map the McMurray Formation.

The seismic data quality is such that seismic interpretation of reservoir thickness, structure of the oil sands zone and the underlying basement of the Devonian Beaverhill Lake Group show good correlation with the well data. Once the seismic has been fully integrated with the core holes an excellent picture of the subsurface emerges. The seismic program also improves the level of confidence in predicting the reservoir extent and thickness in areas where no well data yet exists. In addition, the seismic survey assisted in providing information on the gas zones in the Grand Rapids and Clearwater Formations.

The technical field parameters for the seismic program are as follows:

- all activity was performed during frozen winter conditions;
- 100 m source line interval, 80 m receiver line interval;
- up to 0.5 kg dynamite source placed at no more than 9 m deep;
- 1 ms sample rate with ARAM 24-bit recording equipment and marsh geophones;
- processed and merged by experienced personnel at Key Seismic;
- bin spacing in the subsurface at 20 m x 20 m;
- useful bandwidth of 5 to 180 Hz;
- high signal-to-noise ratio; and
- empirical analysis shows data responds to 1 to 2 m gas sands.

Figure B.2.3-8 shows the isopach of the oil sands using core hole data and Figure B.2.3-9 shows the correlation of the bitumen pay zone derived from logs and core with the interpretation of the 3D seismic data of the bitumen pay zone.

B.2.4 Bitumen Distribution and Reserves

The oil sands pay zone has been identified and characterized by integrating the seismic, log and core data into a resource model.

B.2.4.1 Bitumen Reservoir Modeling

The project database net pay maps and sections were used to construct the Project Area. Resource values were estimated based on the criteria in Table B.2.4.1.

Table B.2.4.1 Criteria Used to Estimate Bitumen Resources

PARAMETER	VALUE
Bitumen saturation (core)	>6 Wt%
Bitumen saturation (log)	RT > 20 Ohms
Sand Porosity (log density)	>27%
Gamma Ray (log)	<75 API
Minimum net pa	>10m

B.2.4.2 Bitumen Reservoir Quality

Within the Project Area, the reservoir's oil sands pay zone thickness ranges between 10 m to 30 m and averages 22 m. Table B.2.4.2 lists the average reservoir parameters and fluid properties within the Project Area based on logs, core and seismic data derived from the exploration programs.

Table B.2.4.2 Key Reservoir Parameters

PARAMETER	VALUE
Pay Zone Thickness (m)	22
Lateral Well Pair Spacing (m)	100
Horizontal Well Length (m)	600 – 900
Porosity	33%
Oil Saturation	80%
Initial Reservoir Pressure KiloPascals	3500 - 4500
Initial Reservoir Temperature (^{o}Celsius)	15
Bitumen Viscosity at T_{RES} (Centipoise)	>1,000,000
Permeability (Darcies)	3 – 9

B.2.4.3 Bitumen-in-Place Estimates

Connacher has estimated bitumen-in-place based on net pay mapping and an assessment of oil sands quality using core and interpreted logs and geophysical mapping. 3D seismic coverage gives Connacher a better understanding of the spatial distribution of resources than drilling alone. Using all these data sources, the company constructed a model of the resource and estimated the bitumen-in-place for each of the contiguous pods of oil found in the Project Area (Table B.2.4.3). The oil sands pay zone map on which this estimate is based is shown in Figure B.2.3-2.

Table B.2.4.3 Bitumen-In-Place Estimate for Pods in the Project Area

Pods	Area (e^6m^2)	Area (ha)	Net volume (e^6m^3)	Avg Net Pay (m)	Est'd Avg Porosity	Pore volume (m^3)	Avg Oil Sat (%)	HCPV oil (m^3)	HCPV oil (MMbbl)
1A	8.9	894	160.3	17.7	33.0%	52.9	85%	45	283
1B	1.1	110	20.6	18.4	33.0%	6.8	85%	6	36
1C	2.1	207	38.8	18.3	33.0%	12.8	85%	11	68
5A & 2A	13.1	1,308	248.7	18.8	32.4%	80.6	79%	64	400
2B	3.1	308	63.1	20.2	32.0%	20.2	75%	15	95
2C	1.0	100	16.2	15.7	32.0%	5.2	75%	4	24
2D	1.6	164	27.3	16.3	32.0%	8.7	75%	7	41
5B	1.0	97	24.9	25.0	32.0%	8.0	75%	6	38
4A	2.3	233	42.4	17.9	32.4%	13.7	79%	11	68
4B	1.7	175	33.5	18.8	32.4%	10.8	79%	9	54
4C	2.5	246	42.4	16.9	32.4%	13.7	79%	11	68
4D	Additional Exploration								
Totals	38.4	3,841	718					187	1,177

Based on computer simulations and field results reported for other SAGD projects, Connacher estimates that in the thicker and higher quality net pays approximately 60% of the bitumen originally in place is recoverable by the SAGD process. A discussion with respect to performance of the SAGD process and anticipated bitumen recovery estimates is provided in Section B.3 – Reservoir Recovery Process.

B.2.4.4 Associated Gas and Water Zones

Associated gas is defined as gas in direct contact with recoverable bitumen resources. The gas may be present due to the long term biodegradation of the oil or it may have migrated into the McMurray formation over time. Either way, it may affect the recoverability of the bitumen depending on whether the gas has already been produced to lower reservoir pressures or has remained unevaluated and remains at virgin conditions. The isopach of associated gas is shown in Figure B.2.4-1. Connacher is familiar with the issue and employs appropriate SAGD technology to ensure maximum recovery of the bitumen.

There is also non associated gas in the Project Area, however it does not pose a threat to SAGD operations given it is separated vertically and laterally by impermeable shale of the McMurray Formation. The isopach of the non-associated gas is shown in Figure B.2.4-2. A list of all the McMurray flowing and suspended gas well completions in the immediate Project Area is shown in Table B.2.4.4. Mudstones within the McMurray provide the effective cap over all the McMurray oil sand "pods" in the Project Area. The overall thickness and distribution of the caprock is shown in Figure B.2.4-3.

Water zones can easily be identified on standard well logs with the following criteria: sand content > 50% on Gamma; >27% porosity; and <10 ohm*m resistivity. The wells in the Project Area show that water is present only at the base of the McMurray and the water is believed to statically trapped in local erosional lows of the Woodbend. The distribution and thickness of the water is illustrated in Figure B.2.4-4 and will have little impact on the successful recovery of the bitumen reserves.

Table B.2.4.4 Gas Wells in the Project Area

CPA Pretty Well ID	Well Status Text	Current Operator Name	Producing Pool Name	In Area
100/09-27-081-11W4/00	Flowing GAS	Iteration Enrg Ltd	MCMURRAY Q3Q	EIA
100/10-27-081-11W4/03	Flowing GAS	Iteration Enrg Ltd	MCMURRAY R2R	EIA
100/09-32-081-11W4/02	Flowing GAS	Iteration Enrg Ltd	COMMINGLED POOL 012	EIA
100/08-34-081-11W4/00	Flowing GAS	Iteration Enrg Ltd	COMMINGLED POOL 012	EIA
100/12-34-081-11W4/00	Flowing GAS	Iteration Enrg Ltd	COMMINGLED POOL 012	EIA
100/06-04-082-11W4/00	Flowing GAS	Iteration Enrg Ltd	COMMINGLED POOL 012	EIA
100/08-06-082-11W4/00	Flowing GAS	Iteration Enrg Ltd	MCMURRAY S3S	EIA
100/12-29-082-11W4/02	Flowing GAS	Iteration Enrg Ltd	CLWT UND	EIA
100/10-30-082-11W4/02	Susp GAS	Iteration Enrg Ltd	CLEARWATER C	EIA
100/10-30-082-11W4/03	Flowing GAS	Iteration Enrg Ltd	GRAND RAPIDS C	EIA
102/10-30-082-11W4/00	ABD GAS	Iteration Enrg Ltd	GRAND RAPIDS C	EIA
100/11-31-082-11W4/00	ABD GAS	Iteration Enrg Ltd	GRD RP UND	EIA
100/01-07-082-12W4/00	ABD GAS	Cdn Nat Rsrcs Lmtd	MCMURRAY Y	EIA
100/07-08-082-12W4/00	ABD GAS	Cdn Nat Rsrcs Lmtd	MCMURRAY FF	EIA
100/16-08-082-12W4/00	Susp GAS	Husky Oil Oprtns Ltd	MCMURRAY FF	EIA
100/16-08-082-12W4/03	Flowing GAS	Husky Oil Oprtns Ltd	COMMINGLED POOL 001	EIA
100/07-09-082-12W4/00	Susp GAS	Paramount Enrg Operating	MCMURRAY FF	EIA
100/08-09-082-12W4/00	Flowing GAS	Paramount Enrg Operating	GRD RP UND	EIA

Table B.2.4.4 Gas Wells in the Project Area

CPA Pretty Well ID	Well Status Text	Current Operator Name	Producing Pool Name	In Area
100/06-10-082-12W4/02	Flowing GAS	Iteration Enrg Ltd	GRAND RAPIDS A	EIA
100/05-16-082-12W4/00	Susp GAS	Paramount Enrg Operating	MCMURRAY S	EIA
100/05-16-082-12W4/03	Flowing GAS	Paramount Enrg Operating	COMMINGLED POOL 001	EIA
100/10-17-082-12W4/02	Flowing GAS	Paramount Enrg Operating	COMMINGLED POOL 001	EIA
102/05-21-082-12W4/02	Flowing GAS	Connacher O&G Lmtd	COMMINGLED POOL 002	EIA
100/06-27-082-12W4/00	Flowing GAS	Iteration Enrg Ltd	MCMURRAY W	EIA
100/07-28-082-12W4/00	Flowing GAS	Iteration Enrg Ltd	MCMURRAY R	EIA
100/07-28-082-12W4/02	Flowing GAS	Iteration Enrg Ltd	MCMURRAY W	EIA
100/11-33-082-11W4/00	ABD GAS Zone	Iteration Enrg Ltd	MCMURRAY OO	1 Section
100/11-33-082-11W4/02	ABD GAS	Iteration Enrg Ltd	U GRD RP UND	1 Section
100/08-02-082-12W4/00	ABD GAS Zone	Iteration Enrg Ltd	COMMINGLED POOL 004	1 Section
100/08-02-082-12W4/02	Flowing GAS	Iteration Enrg Ltd	GRAND RAPIDS A	1 Section
100/07-03-082-12W4/00	Flowing GAS	Iteration Enrg Ltd	COMMINGLED POOL 004	1 Section
100/07-03-082-12W4/02	Flowing GAS	Iteration Enrg Ltd	GRAND RAPIDS A	1 Section
100/08-04-082-12W4/00	Flowing GAS	Paramount Enrg Operating	GRAND RAPIDS A	1 Section
100/14-05-082-12W4/00	Drilled & Cased	Paramount Enrg Operating		1 Section
100/14-05-082-12W4/02	Susp GAS	Paramount Enrg Operating	COMMINGLED POOL 001	1 Section
100/08-06-082-12W4/00	Susp GAS	Paramount Enrg Operating	MCMURRAY Y	1 Section
100/07-18-082-12W4/00	Susp GAS	Husky Oil Oprtns Ltd	MCMURRAY P	1 Section
100/07-18-082-12W4/02	Flowing GAS	Husky Oil Oprtns Ltd	COMMINGLED POOL 001	1 Section
100/02-19-082-12W4/00	Flowing GAS	Cdn Nat Rsrcs Lmtd	MCMURRAY V	1 Section
100/02-19-082-12W4/02	Susp GAS	Cdn Nat Rsrcs Lmtd	COMMINGLED POOL 001	1 Section
100/04-03-083-11W4/00	ABD Zone	Iteration Enrg Ltd		1 Section
100/04-03-083-11W4/02	Susp GAS	Iteration Enrg Ltd	MCMURRAY VV	1 Section
100/04-03-083-11W4/03	Flowing GAS	Iteration Enrg Ltd	U MANN UND	1 Section
100/04-03-083-11W4/04	Flowing GAS	Iteration Enrg Ltd	GRD RP UND	1 Section
100/02-04-083-11W4/00	ABD GAS	Iteration Enrg Ltd	GRAND RAPIDS B	1 Section

B.2.5 Hydrogeology

Source water for the Project will come from water wells drilled and completed in the Lower Grand Rapids Formation (Section B.8.4 – Fresh Water Supply and Storage). The hydrogeology of the oil sand leases and the Project Area are described in detail in the Hydrogeology Report (CR #3 and Section D.3).

B.3 RESERVOIR RECOVERY PROCESS

This section evaluates the Project's reservoir recovery process.

B.3.1 Recovery Process Selection

The average reservoir parameters and fluid properties within the Project Area are listed in Table B.2.4.2. Based on the depth (~480 m), thickness (10 to 30 m) and high viscosity (> 1,000,000 cp) the only commercially viable process available to Connacher is the SAGD process.

There are numerous SAGD operations in the Athabasca oil sands deposits (e.g., Cenovus's Foster Creek and Christina Lake, Suncor's McKay River and Firebag, JACOS' Hangingstone, ConocoPhillips' Surmont, MEG's Christina River, OPTI Nexen Long Lake and Connacher's Great Divide (Pod One) and Algar). Other projects are in approval or development stages. SAGD is a well know method for recovering the deeper bitumen deposits that cannot be economically mined from the surface.

B.3.2 SAGD Recovery Process Description

Connacher's current operations and the Expansion Project are typical SAGD operations. A pair of wells is drilled horizontally for 600 to 900 m at the base of the reservoir and approximately 475 m below the surface. The lower well is the producing well. It is drilled 2 m above the base of the reservoir. The steam injection well is drilled 5 m above it. Steam is continuously injected through the upper wellbore into the reservoir and a steam chamber is formed which heats the formation and the bitumen. The heated bitumen drains into the lower horizontal well and flows or is pumped to the surface.

In the first expansion phase the Project Area will have a total of 96 well pairs operating with 34 well pairs from the Great Divide and Algar approved areas and 62 from the expansion area. A total of 14 surface pads will be required for these 96 well pairs.

The well pairs are operated in three phases:

"Circulation Phase" - the process starts with circulation in which the well pairs are preheated until there is relatively even heating the along the whole horizontal length and communication is eventually established between the injector and producer. This phase is expected to take 60 to 90 days.

"SAGD Phase" - following the circulation phase, steam is injected into the injection well to form a continuously growing steam chamber. Hot produced fluid from the edges of this steam chamber drains into the lower producing well and depending on the operating pressure selected either flows or is pumped to surface.

"Wind Down Phase" - at some point in the operation, as chamber steam reaches the top of the pay zone and extends horizontally, productivity slows and it becomes uneconomical to continue injecting steam. This leads into the final "Wind Down Phase", in which steam injection is continuously reduced until production is terminated and the wells abandoned and the well pad leases reclaimed.

The Project will operate at a pressure below the fracture pressure of the McMurray formation. A recent "mini frac" test conducted on well 1AB/14-27-82-12W4, within the Project Area, estimated a bottom hole fracture pressure at 8139 kPa, the estimate fracture closure pressure of 6840 kPa, and a reservoir pressure of 4578 kPa.

B.3.3 Bitumen Production Rate and Recovery Estimates

Connacher and its engineering advisors use a combination of computer simulation and analogy to estimate bitumen production, recovery and SOR.

B.3.3.1 Well Production Forecasts

As discussed in Section B.2.3 the Project has a number of distinct resource areas and within each area the resource quality varies. Connacher used a combination of analytical, computer simulations and historical performance of the existing Pod One wells to determine production forecasts within each of the resource area. These are summarized and combined into single well pair average forecasts. Forecasts of oil rate, steam rate, steam/oil ratio (SOR) are shown for each area in Table B.3.3.1.

Table B.3.3.1 Production, Injection and SOR Forecasts by Resource Area

Resource Area	Year	1	2	3	4	5	6	7	8	Cum e^3m^3	Cum mbbls
Oil Production m^3/day/well											
1	High Producer	82	134	151	139	128	118	88	24	315	1984
	Low Producer	45	66	64	59	54	50	46	43	156	983
	Average	62	89	86	79	73	59	34	12	180	1131
2	High Producer	76	130	137	126	116	100	33	11	266	1671
	Low Producer	46	67	63	58	54	49	37	13	142	891
	Average	53	78	75	69	64	57	38	14	164	1029
4	High Producer	64	94	89	82	75	70	30	11	188	1182
	Low Producer	48	69	65	60	56	51	47	20	152	957
	Average	50	72	68	62	58	53	44	20	156	979
5	High Producer	78	127	126	116	107	92	30	11	251	1577
	Low Producer	43	60	55	51	47	43	26	10	123	773
	Average	52	74	70	65	60	51	23	6	146	919
Overall Average		54	78	75	69	63	55	35	13	161	1,014
Steam Injection m^3/day/well											
1	High Producer	278	352	371	281	281	281	141	0	724	4556
	Low Producer	265	302	243	220	220	220	220	220	697	4381
	Average	282	330	270	253	252	187	64	18	604	3801
2	High Producer	299	429	424	349	349	262	0	0	771	4849
	Low Producer	274	331	238	238	238	238	119	0	611	3844
	Average	277	328	270	248	248	232	115	15	633	3981
4	High Producer	274	332	239	239	239	239	0	0	571	3590
	Low Producer	264	296	210	210	210	210	210	0	587	3694
	Average	264	292	214	211	211	211	162	16	578	3633
5	High Producer	313	476	407	368	368	276	0	0	806	5067
	Low Producer	268	279	212	212	212	212	53	0	529	3324
	Average	280	324	258	246	246	195	28	0	576	3621
Overall Average		276	318	253	240	240	206	92	12	598	3,759
Cum Steam/Oil Ratio											
1	High Producer	3.4	2.9	2.7	2.5	2.5	2.5	2.4	2.3		
	Low Producer	5.8	5.1	4.6	4.4	4.3	4.3	4.4	4.5		
	Average	4.6	4.1	3.7	3.6	3.6	3.5	3.4	3.4		
2	High Producer	3.9	3.5	3.4	3.2	3.2	3.1	2.9	2.9		
	Low Producer	5.9	5.3	4.8	4.6	4.6	4.6	4.5	4.3		
	Average	5.2	4.6	4.3	4.1	4.1	4.1	4.0	3.9		
4	High Producer	4.3	3.8	3.4	3.3	3.3	3.3	3.1	3.0		
	Low Producer	5.5	4.8	4.2	4.0	4.0	4.0	4.1	3.9		
	Average	5.3	4.6	4.1	3.9	3.9	3.9	3.9	3.7		
5	High Producer	4.0	3.8	3.6	3.5	3.5	3.4	3.3	3.2		
	Low Producer	6.2	5.3	4.8	4.6	4.6	4.6	4.4	4.3		
	Average	5.4	4.8	4.4	4.3	4.2	4.2	4.0	3.9		
Overall Average		5.1	4.5	4.1	3.9	3.9	3.9	3.8	3.7		

Computer Simulation

Computer simulations used the CMG's STARS, SAGD, simulator-developed, numerical models of a 700 m single-well. The basic type model is a 20 x 12 x 67 rectangular grid, with primarily one metre layers. The grid is nested with finer blocks near the wellbore (wellbore block is one metre laterally). Other simulation data match closely with what has been used in the previous datasets, which relied heavily on industry analogs. Average reservoir data from the project geological database were used where available, except for bitumen PVT data that were extrapolated from information on the Dover SAGD project.

The simulated operations included a traditional SAGD start-up, with low-pressure operation using a down-hole pump beginning near or after the second year of continuous operation.

Table B.3.3.2 summarizes the simulator cases that represented different reservoir conditions existing in the Project Area.

In all cases, the bitumen was assumed to be at hydrostatic pressure. There is no associated gas in the proposed development areas and no significant bottom or top water. There are no direct measurements of bitumen or water pressure in the area and the pressure modeled (3,500 kPa) was considered conservative in terms of the SOR.

Many parallels to the Hangingstone zones exist, and in the north area these simulations paid attention to the complexities relating to varying amounts of lower saturation sands, clast areas, breccia, and varying degrees of shaliness in portions of the area. Gas is limited to area 1A which was addressed in the Great Divide Pod One Application. Except for the small water zone encountered in the central area of 2A, water zones do not occur in the Project Area connected reservoir intervals. Consequently, none of the complexities frequently encountered in Athabasca reservoirs need to be considered in the modes developed for Project.

An effective pre-heat period is paramount in establishing proper SAGD performance, and this process is simulated within each run utilizing an analytical heat/temperature set block model.

More complex simulation of the Project Area will result from full geo-statistical modeling results, when they come available. For the present, the type models used, bracket ranges of acceptable rate and recovery performance which will provide for commercial viability. Additional stages of simulation will focus on well management issues during operations, through the longer project run period.

Table B.3.3.2 Summary of Simulation Runs

Well Vertical Separation is 5 m														
Production Well is 2 m above base of Oil Sand									**Cumulative Performance**					
#	**Run Name**	**Well Length (m)**	**Gross Pay (m)**	**Porosity**	**So**	**Permeability**		**PI Bitumen (KPa)**	**Bitumen Prod E^3m^3**			**Cum SOR m^3/m^3**		
						KH (md)	**KV (md)**		**Year 1**	**Year 3**	**Year 9**	**Year 1**	**Year 3**	**Year 9**
1	T 1	700	28	0.32	0.72	6500	3800	3456	21	112	332	4.4	2.8	2.6
2	T 2	700	28	0.32	0.66	6500	2600	3456	27	110	229	4.1	2.8	3.7
3	T 3	700	20	0.32	0.72	4500	3800	3456	23	94	161 *	3.9	3.2	5.8*
4	T 4	700	28	0.32	0.80	6500	3800	3456	28	131	404	3.2	2.4	2.4
5	T 5	700	28	0.32	0.80	6500	3800	3456	28	131	404	3.2	2.4	2.4
6	T 6	700	25	0.32	0.85	6500	4200	3456	32	126	409	2.8	2.3	2.1

Analogy

Connacher uses the performance of the JACOS SAGD project and the initial performance of the Great Divide project as analogies.

The JACOS project has operated a number of SAGD well pairs for over five years and the better reservoir sections are comparable to those of the Project Area. In better sections of the McMurray reservoir, well productivity at JACOS has exceeded 159 m^3 (1000 bpd) on a sustained basis.

The initial performance of 17 well pairs for the Pod One area is shown in Figure B.3.3-1. In better sections of this project, the historical production has exceeded 127 m^3/day (800 bpd)

B.3.3.2 Recovery Estimates

The current development plan for the Project Area, over three phases includes 239 horizontal well pairs as shown in Figure B.3.3-2. The recovery from these wells is estimated from the reservoir volume affected by the wells, the geometric configuration (i.e. placement of the producer above the base and the well spacing) and the residual saturation of bitumen in the steam swept zone. Table B.3.3.3 lists the calculated recovery on a pad basis for all areas in the Project Area.

Over the Project Area, the expected recoveries are approximately 54% of the bitumen-in-place.

Table B.3.3.3 Calculated Recovery for Pads in the Project Area

Pads	EIA Phase	Area (ha)	Average Porosity	Avg Oil Sat (%)	Avg Net Pay (m) Volume	(2) Planned Development (Pads) OBIP 10^3m^3	Losses %	(3) Developable OBIP 10^3m^3	Recovery within Developable Area%	(4) Estimated Recoverable Volumes 10^3m^3	(4) Estimated Recoverable Volumes mmbbls	OBIP Method
Pad 101N Centre	Pod 1	39.4	32%	85%	18.8	1,650	36%	1,054	80%	843	5,304	Petrel
Pad 101S	Pod 1	32.6	32%	82%	19.8	1,707	36%	1,090	80%	872	5,485	Petrel
Pad 102 (5)	Pod 1	31.6	32%	85%	19.1	1,525	36%	974	80%	779	4,901	Petrel
Pad 102 Ext S West (2)[1]	Pod 1	16.6	32%	81%	20.9	803	36%	513	80%	410	2,579	Petrel
Pad 201E (5)	Algar	43.2	33%	75%	19.6	2,017	36%	1,288	70%	902	5,672	Petrel
Pad 201W (1)	Algar	9.4	31%	71%	18.2	375	36%	240	70%	168	1,055	Petrel
Pad 202	Algar	49.6	31%	70%	17.7	1,891	36%	1,208	70%	845	5,317	Petrel
Pad 203 E(7)	Algar	58.0	32%	73%	26.1	3,467	24%	2,648	70%	1,854	11,659	Petrel
Pad 203 W(1)	Algar	9.4	30%	68%	23.0	438	36%	280	65%	182	1,144	Petrel
Pad 104	1	70.9	34%	75%	20.4	3,672	36%	2,345	70%	1,642	10,326	Geostats & Volumetrics
Pad 231	1	50.2	31%	67%	24.0	2,496	36%	1,594	65%	1,036	6,518	Geostats & Volumetrics
Pad 232	1	40.0	32%	69%	26.4	2,315	24%	1,768	65%	1,149	7,229	Geostats & Volumetrics
Pad 233	1	49.2	32%	69%	22.0	2,397	36%	1,531	65%	995	6,260	Geostats & Volumetrics
Pad 234	1	49.4	31%	68%	22.1	2,320	36%	1,482	65%	963	6,058	Geostats & Volumetrics
Pad 235 NW	1	31.7	32%	67%	19.0	1,283	36%	820	65%	533	3,351	Geostats & Volumetrics
Pad 235 SW	1	41.4	32%	69%	22.5	2,019	36%	1,289	65%	838	5,271	Geostats & Volumetrics
Pad 501	1	49.0	33%	71%	24.1	2,728	36%	1,742	70%	1,219	7,670	Geostats & Volumetrics
Pad 502	1	34.6	32%	68%	25.7	1,909	25%	1,440	65%	936	5,888	Geostats & Volumetrics
Pad 503	1	51.3	32%	70%	23.5	2,664	36%	1,701	70%	1,191	7,490	Geostats & Volumetrics
Pad 105	2	74.2	33%	72%	19.7	3,451	36%	2,204	70%	1,543	9,704	Geostats & Volumetrics
Pad 111	2	47.0	32%	72%	21.0	2,277	36%	1,454	70%	1,018	6,403	Geostats & Volumetrics
Pad 112	2	47.7	32%	72%	20.8	2,279	36%	1,455	70%	1,019	6,408	Geostats & Volumetrics
Pad 113	2	40.2	31%	70%	23.6	2,101	36%	1,342	70%	939	5,908	Geostats & Volumetrics
Pad 114	2	33.0	33%	72%	23.3	1,805	36%	1,153	70%	807	5,077	Geostats & Volumetrics
Pad 204	2	53.5	32%	71%	24.5	2,944	36%	1,880	70%	1,316	8,279	Geostats & Volumetrics
Pad 205	2	75.5	32%	70%	26.0	4,349	25%	3,280	70%	2,296	14,443	Geostats & Volumetrics

Table B.3.3.3 Calculated Recovery for Pads in the Project Area

Pads	EIA Phase	Area (ha)	Average Porosity	Avg Oil Sat (%)	Avg Net Pay (m) Volume	(2) Planned Development (Pads) OBIP 10^3m^3	Losses %	(3) Developable OBIP 10^3m^3	Recovery within Developable Area%	(4) Estimated Recoverable Volumes 10^3m^3	(4) Estimated Recoverable Volumes mmbbls	OBIP Method
Pad 206	2	59.5	31%	67%	21.5	2,632	36%	1,681	65%	1,093	6,873	Geostats & Volumetrics
Pad 101N East (2)	2	13.8	32%	84%	18.1	498	36%	318	80%	255	1,601	Petrel
Pad 101N West (1)	2	7.9	30%	82%	15.8	239	41%	141	80%	113	709	Petrel
Pad 102 Outer North	2	5.1	31%	83%	19.4	242	36%	154	80%	124	777	Petrel
Pad 102 Outer South	2	6.0	32%	85%	19.4	284	36%	181	80%	145	913	Petrel
Pad 102 Ext S East (3)	2	20.2	30%	84%	19.4	747	36%	477	80%	382	2,400	Petrel
Pad 401	2	25.9	32%	79%	17.8	1,235	36%	788	75%	591	3,719	Volumetric
Pad 402	2	40.7	32%	79%	20.6	2,214	36%	1,414	75%	1,060	6,669	Volumetric
Pad 403	2	50.2	32%	79%	24.2	3,212	36%	2,052	75%	1,539	9,678	Volumetric
Pad 404	2	49.4	32%	79%	20.7	2,696	36%	1,722	75%	1,292	8,123	Volumetric
Pad 106	3	49.3	28%	70%	23.4	2,254	36%	1,439	65%	936	5,885	Geostats & Volumetrics
Pad 107	3	28.4	32%	69%	16.5	1,045	38%	644	65%	418	2,632	Geostats & Volumetrics
Pad 108	3	41.0	32%	71%	22.1	2,025	36%	1,293	70%	905	5,695	Geostats & Volumetrics
Pad 109	3	52.8	32%	71%	22.6	2,710	36%	1,731	70%	1,211	7,619	Geostats & Volumetrics
Pad 110	3	16.8	32%	68%	18.8	680	36%	434	65%	282	1,775	Geostats & Volumetrics
Pad 115	3	36.0	30%	61%	15.9	1,029	41%	607	60%	364	2,292	Geostats & Volumetrics
Pad 116	3	35.2	36%	75%	16.3	1,531	38%	943	70%	660	4,154	Geostats & Volumetrics
Pad 207	3	36.3	30%	65%	19.4	1,344	36%	858	60%	515	3,239	Geostats & Volumetrics
Pad 208	3	24.8	30%	64%	20.2	969	36%	619	60%	371	2,337	Geostats & Volumetrics
Pad 209	3	34.7	32%	71%	21.1	1,658	36%	1,059	70%	741	4,661	Geostats & Volumetrics
Pad 504	3	29.3	31%	69%	23.5	1,493	36%	954	65%	620	3,898	Geostats & Volumetrics
Pad 505	3	46.5	32%	70%	23.8	2,462	36%	1,572	70%	1,101	6,922	Geostats & Volumetrics
Pad 506	3	48.1	33%	72%	27.8	3,104	24%	2,371	70%	1,660	10,438	Geostats & Volumetrics
Pad 507	3	50.0	32%	67%	17.2	1,814	36%	1,158	65%	753	4,736	Geostats & Volumetrics
Pad 405	3	50.1	32%	79%	22.1	2,910	36%	1,859	75%	1,394	8,768	Volumetric
Pad 406	3	Additional Exploration										Volumetric

Table B.3.3.3 Calculated Recovery for Pads in the Project Area

Pads	EIA Phase	Area (ha)	Average Porosity	Avg Oil Sat (%)	Avg Net Pay (m) Volume	(2) Planned Development (Pads) OBIP 10^3m^3	Losses %	(3) Developable OBIP 10^3m^3	Recovery within Developable Area%	(4) Estimated Recoverable Volumes 10^3m^3	(4) Estimated Recoverable Volumes mmbbls	OBIP Method
Pad 407	3	49.6	32%	79%	21	2,741	36%	1,750	75%	1,313	8,257	Volumetric
Pad 408	3	33.3	32%	79%	19	1,715	36%	1,095	75%	821	5,167	Volumetric
Pad 409	3	23.8	32%	79%	19	1,237	36%	790	75%	593	3,728	Volumetric
						103,604			Totals	47,548	299,063	

Notes

1 Includes 1 wellpair drilled form Pad 101 S

2 Drainage area extends 50m beyond wells in all directions

3 **Estimated Losses within the SAGD Interval**

Net Pay (m)	15	16	17	18	19	20	21	22	23	24	25	26
Heel	4%	4%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%
Toe	4%	4%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%
Below Producer	7%	6%	6%	6%	5%	5%	5%	5%	4%	4%	4%	4%
InterWell	27%	25%	24%	22%	21%	20%	19%	18%	17%	17%	16%	15%
Total	41%	38%	36%	34%	32%	31%	29%	28%	27%	26%	25%	24%

4 Estimated Recovery in Developable zones. Estimated Adjustments for Quality

Oil Saturation	60%	65%	70%	75%	80%
Recovery	60%	65%	70%	75%	80%

Volumetric = Based on Net Pay internal Mapping and GLJ average reservoir Parameters
Geostats & Volumetrics = Qualiy based on Geostats, Volumetrics based on Digitized Net Pay Mapping
Geostats = Petrel Geostat Model (HBK)

B.3.3.3 Development Plans and Schedules

The Project will be developed in three phases (Figure B.3.3-2) and the peak production rate is expected to be approximately 7,000 m^3 of bitumen per day. The well pairs required to achieve this level of production are drilled according to the schedule attached in Table B.3.3.4.

Table B.3.3.4 Estimated Well Pair Drilling Schedule by Phase

Year	Existing		Planned		
	Pod 1	Algar	Phase 1	Phase 2	Phase 3
Existing	19	17			
2010	1				
2011					
2012			51		
2013				3	
2014	1		4	3	
2015			2	14	
2016				3	
2017				9	
2018				15	1
2019				31	3
2020					5
2021					23
2022					11
2023					9
2024					3
2025					20
2026					4
2027					3
2028					
Total	21	17	57	78	82

The producing wells are drilled between 1 and 3 m above the base of the oil sands, and average approximately 2 m. This base of oil sands is an elevation interpreted by Connacher to mark the base of the SAGD developable zone. This base is mapped in Figure B.3.3-3 for the Project Area. The trajectories of the horizontal wells are plotted on this contour map and the target elevations for the producers are noted for each of the pads.

The base of oil sands is relatively flat along the length of the horizontal well pairs, however during drilling some of the well pairs will intersect sporadic shale lenses and Connacher may elect to incorporate blank liners in the completion of these wells.

Additional Drilling

Connacher understands that the pad and well pairs development discussed in these sections may not completely develop the whole of the resource. Certain edge well and infill wells may be needed to fully exploit the resource and Connacher may elect to drill these wells as the areas are better defined by the development drilling described in this section. It is expected that most of these additional well pairs will be drilled off existing pads.

B.3.4 Reservoir Performance Monitoring

Connacher will monitor reservoir performance through the measurement of individual well fluid volumes (injection & production), down-hole and wellhead temperature and pressure readings. In addition, Connacher may monitor vertical wells to observe the progress of the steam flood in selected areas.

Production and injection volumes will be measured in accordance with the Facility MARPs (Measurement Accounting and Reporting Plan) manual. This document will be submitted to the ERCB under a separate cover.

Operations staff responsible for monitoring well performance at the production pad will monitor casing integrity. Surface stations will measure any surface heave caused by steam injection in the Project Area.

B.3.5 Caprock Evaluation

The caprock throughout the Project Area consists of a mixture of muddy inclined hetrolithic strata (IHS) and mudstones and lies directly above potentially productive zones of the bitumen filled oil McMurray sands. The muddy IHS consists of 80% shale by volume and can be bioturbated with mud-lined and sand-filled burrows and is interpreted to be deposited in a muddy point bar setting. The light grey mudstones (100% shale) are thinly bedded with the top few centimetres often containing siderite nodules and rootlets and are interpreted to be deposited in a mud flat to swampy environment. Core photos of a caprock from LSD 5-19-082-11W4M are shown on Figure B.3.5-1.

The caprock is essential for maintaining steam within the productive interval for SAGD oil sands recoveries as it acts like a seal and natural barrier to fluid flow as steam chambers to continue to grow as oil is produced. Caprock thickness ranges between 2 and 15 m in Figure B.2.4-3 and is highlighted on two North-South (Figures B.2.3-3 and B.2.3-4) and two East-West regional cross-sections (Figures B.2.3-5 and B.2.3-6).

Connacher has carried out a mini frac tests in the Project Area at 1AB/14-27-82-12W4M and estimated the bottom hole fracture pressure at 8,583 kPa significantly above the plant operating steam pressure (6500 kPa) and bottom hole injection pressures. Specific results from the

The tests are shown in Table B.3.5.1.

Table B.3.5.1 Mini Frac Test Well 1AB/14-27-82-12W4

Test Location	Depth m KB	Estimated Bottomhole Fracture Pressure (kPa)	Estimated Bottomhole Fracture Closure Pressure (kPa)	Estimated Reservoir Pressure (kPa)
Clearwater Shale	390.0 - 395.0	8,463	5,805	3,670
Wabasca Shale	417.5 - 420.5	10,991	10,178	6,487
Oil Sands Cap	449.0 - 452.0	8,583	6,784	4,604
Rich Oil Sands	461.0 - 466.0	8,139	6,840	4,578

Note: Test was conducted in February 2010

B.4 PRODUCTION PADS AND HORIZONTAL WELLS

The SAGD process uses multiple well pairs drilled from common surface pads. The producing wells follow a trajectory 2 m above the top of the Devonian unconformity and the injector follows a parallel trajectory 5 m above this producer. The horizontal section of each well averages 700 m within the bitumen formation, though this can vary between 600 m and 900 m to accommodate differences in thickness and quality within the reservoir.

B.4.1 Well Pad Layout

The new well pads in the Project Area will have from 2 to 9 well pairs drilled from one or two rows. Future pads will be built in three phases (Figures B.1.1-1, B.1.1-2, B.1.1-3) starting with Phase 1 in 2011.

Reservoir structure, surface features and directional drilling technologies influence the surface location of the pads. The facility design for the planned well pads (Figure B.4.1-1) is comprised of aboveground pipelines, supported on piled steel racks that will connect the pads to the central processing facility. Facility design includes:

- high-pressure steam distribution pipeline/header;
- fuel gas/gas lift supply pipeline/header;
- vapour collection pipeline/header;
- production fluids gathering lines;
- connections to the Central Plant by road access, 25 kV power and communication cables (DCS/SCADA);
- steam-injection meters and flow controllers at each well – the steam can be flow controlled to both the tubing (toe) and the casing (heel) of each injection well. During start-up phases, steam goes to each producing well and creates the communication between the injector and producer;
- test separator – production from each producing well will flow through a control valve and into the group or test header. Wells are tested on a routine basis with the test separator. Liquid and vapour streams are metered and sent to the group separator;
- group separator – production from each group production header flows into the group separator where vapours and liquids are separated. The pad group separator pressure sends vapour to the central plant's produced vapour train;
- group pumps to transfer produced liquids from the group separator to the central plant inlet cooling exchangers – pressure control at the central plant ensures the liquids line remains under pressure and limits the amount of flashing/vapour generation in the liquids line;
- pop tank to capture any emergency relieving conditions;
- utilities to control (instrument air), power and data gathering; and
- ditching, berms and contouring to manage surface water drainage collection and topsoil conservation stockpile area.

B.4.2 Drilling and Completion

The proposed horizontal wells for the Project will be started vertically and then drilled at build rates between 7 and 10.5 degrees per 30 m. The wells will intersect the pay zone at 90 degrees off vertical. Current plans call for an average true vertical depth of 500 m from the surface and a horizontal length of 700 m. Total measured well length will be 1350 m, depending on the well trajectory. The injection wells are shown on Figure B.4.2-1 and the production wells are shown on B.4.2-2.

The vertical surface hole will be drilled, cased and cemented in place with thermal cement. The surface casing will meet requirements of ERCB Directive 8.

The intermediate hole will be drilled vertically to kickoff depth of approximately 220 m, at which point directional drilling will start. The intermediate hole will be drilled using a directional bottom hole assembly consisting of a positive displacement mud motor and a measurement while drilling (MWD) system.

Once the horizontal section is reached, intermediate casing will be cemented to surface with thermal cement. Industry recommended practices along with third party finite node analysis will aid in determining the weight and grade of the intermediate casing. All intermediate casing will have premium high-strength connections.

The horizontal main hole will be drilled and a gamma ray log run in conjunction with the MWD package to determine whether any non-reservoir formation was encountered. A sand control slotted liner or wire-wrapped screen will then be run the length of the horizontal section and “hung” with a high-temperature packer.

The production well will be drilled first, followed by the injection well. A magnetic guidance system will maintain a constant vertical separation of 5 m between the producer and injector.

Disposal of all drilling fluids will be according to ERCB Directive 50. Drilling fluid will be reused between wells and minimal volumes will be stored in above ground tanks. Minimal water volumes will need to be disposed of. At the end of the drilling program, the mud will be stripped back to water. The water will be treated and tested to ensure it meets AENV pump off guide lines and then it will be pumped off. The solid waste resulting from the stripping operation will be disposed of in a Class II land fill. Total volume of drilling waste will be 100 m^3 per horizontal well. Whenever there is an indication that wells may be drilled into heated areas, additional precautions will be taken including setting casing above the McMurray and different mud systems. Connacher will employ observation wells to monitor temperature changes in the formation.

B.4.2.1 Producing Well Completion

The production well will be completed using two tubing strings, a long string landed at the toe of the well and a short string landed at the heel (Figure B.4.2-2). Both tubing strings are open for production and can accommodate a small-diameter coiled tubing string for artificial lift.

During the start-up phase, steam injected into both the injection and production wells warms the reservoir. The heat reduces the viscosity of the bitumen and makes the oil between the injection and production well mobile. This steam circulation phase lasts several months, but once thermal communication is established, the lower well is converted to a producer and the upper well continues steam injection.

The produced fluids from the production wells flow to surface using artificial lift. Initially, the lift comes from sweet natural gas injected down a coiled tubing string. Approximately two years into the producing life of the well the completion will be reconfigured to accommodate a pump.

B.4.2.1 Injection Well Completion

The injection well is completed in a similar manner to the producing well. During normal production, the long tubing string flows steam (near 100 percent quality) into the reservoir at a pressure below the formation’s fracture pressure.

At least one well per pad is instrumented for gathering down hole temperature data.

B.4.2.3 Observation Wells

Observation wells are useful for monitoring reservoir performance. Connacher has not finalized the exact number of these wells. Detailed design of the monitoring program will be completed during the detailed engineering phase of the project. Current thinking is to employ fibre optic or thermocouple string and drill these wells to just below the base of the McMurray oil sands using premium connections and thermal cement.

B.4.3 Drilling Waste Management

Connacher plans to use a water-based drilling fluid system. Notwithstanding potential hydrocarbon contamination from the formation, these mud systems generate waste material largely composed of bentonite clay.

Surface holes will drilled to the bottom of the Quaternary zone and surface casing will be cemented in place. Total waste generated from this section of the hole will be tested and stored at a suitable surface location for the purpose of future land spreading disposal as per ERCB directive 50. Cement returns will be stored and buried at the remote sump locations.

Mechanical solids removal equipment will recycle fluids from the intermediate and horizontal sections of the hole. This technique reduces the volume of liquid requiring disposal. Disposal options for liquid waste include disposal at a licensed, third-party waste disposal facility, or pump-off following Directive 50. Waste-sampling analysis will determine the liquid waste disposal method.

Waste-reduction methods should limit the volume of solid waste from the intermediate and horizontal hole sections. Waste solids from the drilling operations will be analyzed according to the requirements of Directive 50. Should the hydrocarbon levels remain below Alberta Tier I Soil and Water Quality Guidelines for Hydrocarbons (CCME fractions); the waste will be disposed of using the mix-bury-cover method.

If the waste does not meet the requirements of Directive 50 for hydrocarbons, it will be disposed of at an approved waste disposal facility, or bioremediated within the parameters of Directive 50. Selection of the final drilling solids disposal option will be determined from waste sampling analysis.

The drilling mud sump will be located nearby and separated into cells to isolate the various phases of drill mud and cuttings. The locations of the sump sites will be selected and constructed after soil sampling ensures the base material meets the required permeability limits.

B.4.4 Casing Failure Monitoring Program

The SAGD operation is a continuous process operated below the formation fracture pressure. As a result, the down hole tubulars are not subjected to the same stresses that occur from the high temperature and pressure fluctuations seen in cyclic steam processes.

Casing integrity will be monitored by operations staff that monitors well performance at the production pad. Injection and production well pressures and temperatures will be monitored continuously, as will steam flow rates. Any unanticipated changes in these parameters will be investigated immediately to avoid breaches in casing integrity.

The intermediate casing string will provide hydraulic isolation between the oil sands, into which steam will be injected, and the overlying shale. As well, surface casing set below the Quaternary formations will help provide hydraulic isolation. Risks of any intermediate casing failures at the Project will be minimized through the employment of best industry standards for casing and cementing practices.

B.4.5 Well Performance Monitoring

Production wells will be tested at least twice each month. Daily oil, gas and water production will be allocated to the wells, based on battery pro-rations and well test data.

Bitumen, produced water and produced gas will be measured during well testing. Bitumen will be analyzed regularly to monitor quality from the reservoir.

Produced gases will be analyzed regularly for composition. The volume and pressure of steam injected into each injection well will be measured and recorded continuously.

Fluid will be analyzed as frequently as necessary.

B.5 CENTRAL PROCESSING FACILITY (CPF)

The existing Pod One facility is sized to produce approximately 1600 m^3/day of bitumen and Connacher has no plans for additions or modifications. Expansion will occur to the existing Algar CPF.

The Algar CPF is sized to produce and process approximately 1600 m^3/day of bitumen and was designed to be easily expanded at some future point. The expansion will involve installation of an additional process train which will run in parallel to the existing 1600 m^3/day process train. The expansion train will be integrated within the footprint of the existing facility and will add an additional 3,800 m^3/day of processing capacity for a combined total of 5,400 m^3/day bitumen processing capacity at Algar. Combining the 1600 m^3/day of capacity at Pod One with the 5,400 total Algar capacity, the overall lease production capacity will be approximately 7,000 m^3/day of bitumen. This section will focus on the equipment that is required for the expansion of the Algar CPF to add train 2 (3,800 m^3/d).

Figures B.5.0-1 (Sheets 1 to 17) show the process flow sheets for water and steam and Figure B.5.0-2 (Sheets 1 to 13) show the process flow sheets for the oil treating process. Details of the processes carried out in the CPF are provided below.

B.5.1 Central Processing Facility (CPF) Layout

The CPF is located mostly in Section 18- 82-11-W4M. The existing disturbance footprint for the CPF is approximately 530 m by 600 m which will remain essentially unchanged with the expansion.

The plot plan for the CPF is shown on Figure B.5.1-1. Algar will include two facilities. The existing train 1 sized for 1600 m^3/d (10,000 bbl/d) of bitumen and expansion train 2 sized for 3,800 m^3/d (24,000 bbl/d) bitumen. The following description includes equipment for both trains. Included on this drawing is the location of buildings, flare stack, and storage tanks. Table B.5.1.1 and Table B.5.1.2 respectively list the external emission sources and storage tanks associated with the entire CPF. Dispersion modeling associated with these emission points is discussed in detail in the Air Quality Report (Consultant Report #1). A summary of this report is provided in Section D.1.

Table B.5.1.1 External Emission Sources Associated with Central Processing Facility

Name	Design			
	Train 1 (existing)		Train 2 (expansion)	
	#	Height (m)	#	Height (m)
Cogeneration Exhaust Stacks	1	21	1	21
Steam Generator Exhaust Stack	2	30	5	30
Flare Stack - CPF	1	39	-	-
Glycol Heater Exhaust Stack	1	8.2	1	8.2
Utility Steam Generator Stack	1	8.5	1	8.5

Table B.5.1.2 Storage Tanks Associated with Central Processing Facility			
Name	**Product**	**Train 1 (existing) m^3**	**Train 2 (expansion) m^3**
Diluent Storage Tank	Diluent	1600	3200
De-sand Tank	Sediment & Water	350	350
Produced Water IGF Feed Tank	Produced Water	1280	3200
Sales Oil Storage Tank	Dilbit[1]	1600	3200
Production Oil Storage Tank	Dilbit[1]	1600	3200
Produced Water Skim Tank	Oily water	1600	3200
Waste Oil Storage Tank (Slop Tank)	Oily Water	397	-
De-Oiled Water Storage Tank	De-oiled Water	1600	3200
Soft Water Storage Tank	Water	397	
Brine Dissolving Tank	Saturated Salt Water	33	-
Evaporator Feed Tank	De-Oiled Water & Raw makeup water	41.4	82
Off Spec Bitumen Storage Tank	Dilbit[1]	1600	-
Caustic Storage Tank	Sodium Hydroxide	30	-
Boiler Feed Water Tank	Treated Water	1600	3200
Evaporator Waste/Crystallizer Feed Tank	Evaporator Waste	228	375
Boiler Blow Down Tank	Water	320	477
POD 1 Evaporator Waste Tank	Evaporator Waste	100	-
Glycol Storage Tank	Glycol and Water	32	-
Crystallizer Waste Tank		113	180
Floor Drain Tank	Oil and Water	80	80

1 Dilbit – refers to a blend of Diluent and Bitumen

B.5.2 Oil Production System

B.5.2.1 Well Pad Group Separator

Once the heated bitumen, produced gases, steam condensate and water (collectively referred to as either "production fluids", "emulsion", or "reservoir fluid") are extracted from the production wells, it flows to two group separators at the respective well pads. The vapour from the group separator is back pressure controlled and flows to the CPF via an emulsion vapour pipeline. The liquid from the group separator is pumped to the CPF via a separate emulsion pipeline. Using pumps to transport the emulsion allows the CPF inlet vessels to operate at the optimal pressure. The group separator reduces surging from the individual wells and removes the bulk of the produced gas contained in the emulsion. The produced gas is cooled and recovered for use as a fuel source (Section B.5.8.2).

After the steam chamber is significantly developed, electric submersible pumps will be installed in the production wells and lift gas will be discontinued.

B.5.2.2 Inlet Heat Exchange

The emulsion flows to the CPF and is cooled by a number of sets of exchangers. For each set, the first exchanger cross-exchanges the inlet emulsion with boiler feed water and the second exchanger cross-exchanges the inlet emulsion with cooling glycol.

A third set of exchanger's cross-exchanges the vapour from the inlet pipeline with boiler feed water and a fourth set of exchangers that cross-exchange inlet vapour with glycol cooling.

B.5.2.3 Free Water Knockout

Once the emulsion has been cooled, it then flows through three free water knockout (FWKO) separators. The FWKO is a horizontal three phase separator that is used to separate oil, gas and free water (i.e. water not bound to any oil and gas).

Gases released in the FWKO separator are recovered (Section B.5.8.2).

Most of the water in the emulsion is removed in the FWKO. Water from the FWKO is cooled by cross-exchange with glycol and level controlled to the skim tank (Section B.5.3). Oil from the FWKO is level controlled to the treater.

Small quantities of sediments, primarily consisting of sand and silica, are also included in the emulsion. Most of these sediments settle and accumulate in the bottom of the FWKO. High velocity water jets installed at the bottom of the FWKO vessels are used to periodically flush the accumulated sand slurry into a de-sand tank. Inside the de-sand tank, the sediment is allowed to settle. Water and oil in the de-sand tank are subsequently recovered and recycled (Section B.5.4). Sediments in the de-sand tank are removed, from time to time, and hauled offsite to a licensed disposal site.

B.5.2.4 Diluent Addition

After the free water has been removed in the FWKO, a light hydrocarbon diluent (ranging from 60° to 80°API Gravity, depending on the diluent available) is added to the emulsion before it is sent to the treater. Addition of diluent reduces the viscosity and density of the emulsion, which allows conventional oil treating equipment to separate the oil from the water. The diluent will be pumped from the diluent tank to upstream of the treater (Section B.5.2.5). The diluent will initially be trucked to the CPF from the source of purchase.

The diluent will flash to some degree, resulting in a density change for blending purposes. This change in density will have a minimal effect at the blend rates anticipated. Based on engineering calculations using a liquid-vapour simulation program, the shrinkage difference will be in the range of 0.05%, which is not significant in the overall facility accounting.

The diluent compositions will change, depending on the source of the diluent. Connacher will monitor shrinkage, utilizing process software to monitor flashing of diluent light ends. Where the volumes are material to the plant accounting (>0.5%), appropriate adjustments will be made.

B.5.2.5 Gravity Separation and Filtration Vessels

After passing through the FWKO, only a small amount of water and gas remains bound with the bitumen. Diluent is then injected into this bitumen/gas/water mixture. This diluent-bitumen mixture is referred to as "dilbit." Diluent addition improves the specific gravity ratio of the dilbit, aiding in further oil-water-gas separation. The dilbit flows through the gravity separation vessel (treater) and whose function are to produce sales quality dilbit that contains less than 0.5% impurities comprised of basic sediments (sand and silica) and water. After passing through the treater, the cleaned dilbit is cooled by cross-exchange with glycol and level controlled to the production oil tank. Dilbit passes from the production oil tank to the sales oil tank.

The cleaned dilbit being shipped offsite from the sales oil tank via the LACT unit is monitored to ensure that it complies with pre-determined market and shipping specifications. A basic sediment and water (BSW) analyzer and diversion valves are located in the LACT unit.

If the sampled dilbit meets shipping specifications, it will be transported off site. In the event that the sampled dilbit does not meet shipping specifications, it is diverted to the existing off-specification dilbit tank where it is re-processed through the oil recycle and treatment system (Section B.5.4). All tanks (i.e., sales oil tank, production oil tank and existing off-specification bitumen tank) are equipped with a bottom recycle system to prevent a build up of BSW in the bottom of the tanks. Any BSW that has accumulated in these tanks is reprocessed through the oil recycle and treatment system (Section B.5.4).

Water separated in the treaters is cooled and level controlled to the produced water skim tank (Section B.5.3). Gas from the treater is backpressure controlled to the produced gas recovery system (Section B.5.8.2).

B.5.2.6 Emulsion Chemical Treatment

Chemicals are added at various points in the gas-oil-water separation process. Chemicals used are demulsifiers, reverse emulsion breaker and polymers. The chemicals help separate the oil and water and also help mitigate corrosion of piping and vessels. A list of chemicals used in the CPF is provided in Section B.5.21.

B.5.2.7 Water and Solid Composition

The test separators located at the pads will be equipped with meters to measure the water cut along with coriolis meters to measure the mass flow. The water cut meters are full range models with an accuracy of +/- 0.5% of for the oil phase and +/- 1.0% for the water phase. The range of the water cut units is 0 to 100% water cut with a resolution of 0.1%.

The monitoring devices used at this facility will be designed for temperature ranges up to 200°C and 1309 kPag. The actual operating conditions will be 180°C and 1000 kPag.

The coriolis meter will output a density measurement and will be used as a secondary device to confirm the readings obtained from the water cut monitor. A change in density detected by the corilois meter will indicate a possible change in the BS&W which operation staff will investigate. The water cut monitors will be calibrated annually to the same frequency as the coriolis meters used for accounting measurement. The sales oil water cut determination will be done at the pipeline receipt point.

The water cut determination of the diluent will be done by manual sampling and spinning the cuts of each load. As the diluent is a royalty paid product, only diluent actually injected into the process bitumen stream affects the accounting calculations. Operators will monitor the diluent receipts and the diluent tank for water content. If water is found in the loads or accumulates in the tanks, the water will be removed and recycled. As the diluent is a specific product, no water is expected in the diluent receipts.

B.5.3 Produced Water De-Oiling System

Steam condensate and water contained in the emulsion is called "produced water". The purpose of the produced water de-oiling system is to pre-treat the produced water to a feed water quality for making boiler feed water (BFW) by removing oil and sediment before it is demineralized for reuse to generate steam for bitumen recovery (Section B.5.7). Without proper oil and sediment removal, the water demineralization equipment will become inefficient and lose its boiler feed water production capability.

The produced water de-oiling system consists of three operations. First, bulk oil and solids are removed at the skim tank. Next secondary oil separation/removal is provided by the induced gas floatation (IGF) cell. Finally, fine oil droplets and solids are removed (or polished) by an oil removal filter (ORF).

B.5.3.1 Bulk Oil Removal

Following separation in the FWKO, the free water is cooled through a series of heat exchangers to 90°C to prevent the water from boiling when depressurized. The free water is then processed to the produced water skim tank. The skim tank allows primary oil separation where 80 to 90 percent of the dilbit blend in the water separates by gravity. Dilbit is skimmed off the top of the skim tank and is pumped to the existing slop tank (Section B.5.4).

Water from the skim tank then flows by gravity to the IGF feed tank (surge tank).

The IGF feed tank acts as a break between the oil processes and the water de-oiling process equipment by taking up surges or swings in produced water volumes generated during the oil production process. Due to the residence time of the produced water in the IGF feed tank some of the oil will raise to the surface (Stokes Law). A skim system at the surge tank further recovers oil and transfers it to the slop oil storage tanks for treatment (Section B.5.4).

Produced water flows by gravity from the produced IGF feed tank to one IGF vessel.

B.5.3.2 Induced Gas Floatation (IGF)

From the IGF feed tank, the produced water flows by gravity to the IGF vessel where about 90% of the dilbit and emulsion remaining oil is removed. Minute natural gas bubbles are introduced into the bottom of the IGF Vessel in the specific floatation cells (4 total) using a dissolved gas flotation (DGF) pump. As the gas bubbles rise in the water column, they coalesce with the oil droplets in the water, bringing them to the top of the vessel. The coalesced oil is removed as an oily froth. The recovered oil from the IGF cells is sent to the oil recycle and treatment system for further treatment (Section B.5.4). The gas is recovered from the top of the IGF cell, and recycled back into the cell through mixing with the clean water at the DGF pump.

B.5.3.3 Oil Removal Filter (ORF)

For the Algar train 2, two ORFs accomplish the final polishing of the oil and grease present in the water where about 90 to 95% of the remaining oil feeding the units is removed.

Produced water leaving the IGF vessel contains approximately 20 mg/L of oil. Final clean-up to 2 mg/L oil in water will be completed using one set of two ORFs. Water is pumped from the IGF cell through the ORF (a pressure vessel), which have approximately 90% oil removal efficiency. Two filters will be used to provide 100% spare capacity, allowing one unit to be operational while the other one is being backwashed or in stand-by mode.

De-oiled water leaving the ORF is ready for water treatment (demineralization and organic (TOC) removal) downstream at the mechanical vapour compressor evaporation process (Section B.5.6). The de-oiled water is stored in the water storage tank to provide storage and surge capacity for the steam generation system downstream. Recycle water streams are also fed to the deoiled water storage tank (distillate recovered from the forced circulation crystallizers and cooled boiler blow down streams).

The backwash of the ORFs is approximately 1.4% of the total feed. The dirty backwash from the ORF (containing oil and sediment) is sent to the oil recycle and treatment system for further treatment (Section B.5.4)

B.5.4 Oil Recycle and Treatment System

Slop oil and emulsion from the deoiling and oil/water separation process is collected in the slop tank. This oil and emulsion is pumped back into the FWKO for retreatment (Section B.5.2.3).

B.5.4.1 Recycle Free Water Knock Out

A separate recycle free water knock out is not considered for this project. The recycle is pumped back into the FWKO for retreatment. (Section B.5.2.3)

B.5.4.2 Recycle Centrifuge

A separate recycle centrifuge is not considered for this project. The recycle is pumped back into the FWKO for retreatment. (Section B.5.2.3)

B.5.5 Source Water Pre-Treatment

Source water is pumped from the water supply wells to a water storage pond. This pond will allow a minimum inventory of water for storage for the plant while maintaining a continuous supply to the source water treatment system.

From the source water pond the water is pumped to the cartridge filters where suspended solids are filtered. This maintains a clean source, free of suspended material for proper treatment at the source water softeners. Once filtered the water is then processed to the strong acid cation (SAC) water softeners where the hardness ions are removed from the source supply.

The SAC ion exchange process is designed to soften water with total dissolved solids (TDS) up to a concentration up to 8,000 mg/L. The source water for Algar has a TDS of approximately 2,500 mg/l. The process design for the SAC softening system, to meet a Total Hardness feed spec for the evaporators is a train consisting of a single softener. Multiple trains are used to have softening capacity full time. The system design configuration consists of six treatment trains. This design configuration accommodates the high volume of fresh water required at start up period while being suitably designed when the makeup requirement ramps down with the increased produced water flow to the CPF. There is a minimum design flow that a single softener vessel can handle. Softened water is sent to the softened water storage tank.

The SAC water softeners are regenerated using salt (NaCl). The salt is stored in a bulk tank and saturator and is diluted using softened water for regeneration of the SAC resin vessels. The spent or waste regenerant is sent to the crystallizer feed tank where the water is recovered downstream at the crystallizer unit.

B.5.6 Produced Water Treatment System and Boiler Feed Water

After de-oiling (Section B.5.3), the produced water is combined with raw make up water from the softened water storage tanks (Section B.7.2) and treated for use as boiler feed water (BFW) to generate steam. The produced water treatment system consists of pH control via caustic injection and evaporation-distillation process. The water treatment system removes sediment, insoluble oil and grease, hardness, total organic carbon, and dissolved solids from the produced water. Scale inhibitor and antifoam-chemicals are also added in the water treatment system to ensure appropriate water properties (Section B.5.21).

<u>First Stage Evaporation Process: 2 units total</u>

The produced water feed to the evaporation-distillation process will flow from the de-oiled water storage tank to the evaporator feed tank. Also added to the evaporator feed tank are the cooled boiler blow down and the recovered distillate from the forced circulation crystallizer and the waste brine from the Pod One evaporators. Caustic is pumped from the caustic storage tank, introduced into the feed tank and mixed with the produced water to adjust and control the pH. The pH is adjusted close to 12.0 and the water solution is then pumped from the feed tank through a plate and frame heat exchanger to raise its temperature to near boiling point. It then flows to a de-aerator where non-condensable gases such as carbon dioxide and oxygen are removed from the water solution. Part of the pH adjustment is provided through addition of Pod One evaporator blow down to the evaporator feed tank. This stream also reduces the makeup requirement to the system for Algar. The hot de-aerated feed then enters the evaporator sump, where it combines with the re-circulating brine slurry. The hot slurry is pumped into vertical tubes allowing a portion of the feed to evaporate and the rest to fall back into the sump to be re-circulated. The distillate is collected and pumped directly to the boiler feed water (BFW) tank for use in the steam generation process (Section B.5.7). Once the solids are cycled up in the evaporator a part of the stream is bled off as blow down where it is further concentrated before being sent to the forced circulation crystallizer.

The evaporator design consists of a cascade process. Three evaporators in total will make up the process. It is a process train that consists of two first stage plus one second stage evaporators in series. The initial two evaporators split the initial feed water equally and the brine waste recovered from these units is fed to the second stage evaporator. The second stage evaporator does not require a deaerator as do the first stage units. There is no oxygen ingress that occurs in the first stage making the deaerator redundant.

Second Stage Evaporation Process: 1 unit

For this stage the brine slurry that is released from the first stage evaporator towers is pumped to the second evaporator tower. The second tower has a split sump which increases the efficiency of the evaporative process. The second stage evaporator tower collects most of the remaining water as distillate, driving the brine concentration up. In the second stage evaporator vessel the brine concentrates from the first to the second sump. The concentrated brine from the second sump is partially released continuously to the crystallizer feed tank for further distillate recovery and solids concentration.

Typically, 95 to 98% of the produced water feed is converted to distillate (< 5 mg/L total nonvolatile dissolved solids) for reuse in the SAGD process. Distillate is stored in the boiler feed water tank.

The evaporation-distillation process is based on 15,000 m^3/day (96,000 bbl/d) cold water equivalent (CWE) of steam required. It is designed to recover approximately 97% of the produced water feed blend as high quality distillate (i.e., < 5 mg/L total non-volatile dissolved solids). The final distillate product meets the boiler feed water quality for steam production.

B.5.6.1 Evaporator Waste Brine Removal

During the evaporation-distillation process, the concentration of salts in the feed solution is continuously increasing and, without removal, will result in the equipment becoming inefficient and non operational. When solids are cycled up in the evaporator to its final density a portion of the blow down is then continuously discharged at the blow down valve while maintaining the maximum density and solids level. This waste stream is sent to the crystallizer feed tank which provides storage and feeds to the final stage of water recovery (crystallizer). The Algar train 2 will produce a total of 150 m^3/d of concentrated evaporator brine that will be sent to the crystallizer.

B.5.6.2 Crystallizer Process

The concentrated waste brine from the second stage evaporator is collected in the agitated crystallizer feed tank, and then transferred to the crystallizer recirculation line by the crystallizer feed pump. The concentrated brine feed is mixed with the recirculating brine slurry and is pumped through the shell and tube heater. The brine is heated a few degrees as it passes through the heat exchanger and when it re-enters the vapour body, it flashes, effectively converting the sensible heat to latent heat in the form of vapour.

In a vapour compression crystallizer, the vapours produced are collected in the vapour body, pass through an entrainment separator, and enter the suction side of the vapour compressors. The vapour is pressurized and heated by the compressor and is transferred to the shell side of the shell and tube heater where vapour condenses, providing the thermal driving force for evaporation. The condensate is collected in the condensate tank and is recirculated back to the deoiled water tank. The condensate quality is not of suitable quality "as is" for meeting boiler feed water quality.

In the vapour compression crystallizer, crystals are continuously formed within the brine slurry held up in the vapour body vessel, prior to entering the recirculation pump. Upon heating and flashing the brine, water is removed as vapour. The brine becomes supersaturated and the salts precipitate from solution. Organics also are concentrated in this recirculation loop.

A continuous stream of the concentrated crystallizer brine waste slurry is pumped from the crystallizer vapour body to the crystallizer waste tank. This high solid waste containing approximately 100 t/d of waste solids (50% weight solids) will be trucked out to an approved disposal facility.

B.5.6.3 Vapour Recovery at Evaporator and Crystallizer Processes

Most vapour from the evaporator de-aerator, distillate tank, feed tank vents and from the crystallizer condensate tank, heater, feed tank and waste tank vents will be condensed and reprocessed. Non-condensable vapour from the vent will be captured, mixed with the produced gas and then combusted in the boilers. The volume of the non-condensable vapour stream is negligible. The condensables will be captured and sent back to the evaporator feed tank for processing.

B.5.7 Steam Generation System

In order to extract bitumen from the oil sand reservoir, the SAGD process involves injecting steam into the reservoir. Steam generated in the CPF will be delivered to the well pads through above ground interconnecting pipelines. Steam will be generated and distributed at a maximum pressure of 6500 kPag and subsequently reduced in stages through pressure let down valves such that the resulting steam injection pressure at the reservoir face does not exceed the proposed bottom hole operating pressure of 4600 kPag. For generating steam in the CPF, the high quality distillate from the produced water treatment system (Section B.5.6) enables steam to be generated using natural gas fired water tube boilers. Use of water tube boilers are preferred over the use of once through steam generators (OTSGs) because they have higher fuel efficiencies. In addition, water tube boilers have the capability to generate higher quality steam, leading to reduced boiler blow down volumes (3% vs. 20% with OTSGs). Steam generator exhaust stack heights are contained in Table B.5.1.1.

Once the distillate has been collected in the BFW tank, it is pumped into five steam generation boiler units. Chemical addition is important for internal boiler maintenance and surface protection. Oxygen scavenger, phosphate and filming amine chemicals are added during the boiling process to ensure appropriate water quality. The water is then heated to saturation temperature and finally boiled into steam. Each boiler unit is nominally rated at 366 MMBtu/hr and is capable of producing saturated steam at a maximum pressure of 6,500 kPag for distribution to the well pads. A list of chemicals used in the CPF is presented in Section B.5.21.

Flow from the BFW pumps to the boilers is regulated by a control valve located at the boiler. Excess volumes are recycled back to the BFW tank. The small blow down volume from the boilers will be returned to the de-oiled water storage tank via the boiler blow down tank.

B.5.8 Fuel Gas and Produced Gas Recovery System

B.5.8.1 Fuel Gas

The Project will use natural gas as the fuel source and that is currently supplied from a third-party. At this time, Connacher is not contemplating any alternative fuel sources as natural gas, along with some produced gas is the cleanest and most efficient fuel.

The largest gas volume consumed is for fuelling the steam generators and cogeneration equipment. Fuel gas will also be used:

- for piloting flares;
- for heating various components of the Project infrastructure; and
- as blanket gas for tanks and vessels.

Fuel gas energy balances for the Project are provided in Section B.6.2.1.

B.5.8.2 Produced Gas Recovery System - Central Processing Facility

All produced vapours at the CPF are recovered. Produced vapour releases into the atmosphere are not part of normal operating conditions.

Continued use of third-party fuel gas purchased for the Project will be supplemented by using the produced gases from the reservoir. Within the oil production system, produced gases in the emulsion are recovered from the group separator (Section B.5.2.1), the FWKO (Section B.5.2.3) and treater (Section B.5.2.5). These vapours are water saturated and are first cooled to remove the water, leaving a combustible gas, which is directed to a gas mix drum. The produced gas is then blended with fuel gas for subsequent use in the CPF. The recovered water is sent to the skim tank for recycle and use in the SAGD process (Section B.5.3).

The produced gas may contain some sulphur as hydrogen sulphide (H_2S). Based on operating experience from industry SAGD developments, the Project design anticipates a maximum sulphur content of 1.6% H_2S in the produced gas. The maximum sulphur emissions coincide with maximum production rates.

In addition to the produced gas recovery process, a vapour recovery unit (VRU) is provided to recover low pressure vapours from any storage tanks containing hydrocarbons.

Blanket gas is a gas that is placed above a liquid in a tank or vessel to protect the liquid against air contamination by reducing the risk of air getting into the tank. The gas source is located outside the tank or vessel.

Gas from the VRU is recovered and compressed for use as fuel. Low pressure vapour sources are also connected to the flare system (Section B.5.9).

Produced gas energy balances for the Project are provided in Section B.6.2.2.

B.5.8.3 Produced Gas Recovery System - Well Pads

All produced vapours at the well pad are recovered. Vapour releases into the atmosphere are not part of normal operating conditions.

Gas lift will be used initially for the emulsion to flow to the surface. Gas lift involves the injection of natural gas into the bottom of the well to aid in lifting the produced fluids or emulsion to the surface.

Once at the surface, the emulsion will flow to a group separator where the water vapour and gas will be separated from the emulsion (water and bitumen). The vapours will free flow back to the CPF through a dedicated pipeline and the emulsion will be pumped to the CPF in a separate pipeline.

Each well will be able to be tested for two 24 hour periods per month using a two phase separator. The vapours and liquids from the test separators will be recombined into the respective group lines.

B.5.9 Gas Flaring System

Under normal operating conditions, there is no vapour release into the atmosphere. However, a small flow of purge gas is used to prevent air from entering the flare system and a small flow of pilot gas is burned to ensure combustion of vapours during an emergency release. In recognition that equipment malfunction could result in the occurrence of an "over pressurization or depressurization" situation, it is necessary to ensure that provision is made available for safety venting vapours into the atmosphere.

Emergency release of gases will be collected and burned in a flare system. Flaring, or the burning of combustible vapours, is a way of vapour disposal when there is no way to safely contain the gas or use it for another purpose. The basic design philosophy of the flare system is to gather hydrocarbon vapour and liquids, separate any liquids from the vapour and then ignite and burn the hydrocarbon vapour at a reliable maintained flame.

A flare system is located at the Algar CPF. The flare tip includes a wind guard and a continuously burning pilot flame equipped with an electronic ignition system. The flare system is continuously purged with natural gas to prevent air entering the system.

Emissions from any emergency flaring events are expected to contain SO_2 and a small amount of non-combusted H_2S. Combustion efficiencies during emergency releases have not been calculated, as over pressurization or depressurization events are highly transient and infrequent.

The flaring that could occur during the plant operations has been estimated for the following periods:

- normal plant operations - 0 m^3/d; and
- typical plant upset – estimated at six times a year at a rate of 40,115 m^3/hr for 6.5 seconds.

B.5.9.1 Flaring System - Central Processing Facility

The flare system for the CPF consists of a 2.4 m diameter by 6.1 m long knockout drum to collect any liquids, and a 356 mm diameter by 39.0 m high stack (currently exists at Algar). The liquids from the flare knockout are recycled to the oil recycle and treatment system (Section B.5.4) for subsequent use in the SAGD process. A separate 3 m diameter by 12.1 m long pop drum is also connected to the knockout drum and flare stack. The pop drum is for vapour only and liquids will be pumped out and recycled.

B.5.9.2 Pressure Relief System - Well Pad

A pop tank is provided, for safety reasons, as a destination for over pressuring and accidental release of production fluids. When necessary, liquids released to the pop tank will be removed by truck and sent to the CPF for processing. In the highly unlikely event of an over pressurization, any gases sent to the pop tank will be vented to atmosphere. Process piping and vessels are designed to full wellhead design pressure, thereby minimizing the chance of a mechanical pressure safety valve relieving to the pop tank.

B.5.10 Cooling and Heating Systems

To make operating systems within the CPF more efficient, a closed loop water-glycol system based on a 50% (wt.) ethylene glycol solution is used to assist in cooling processes and to recover low grade heat which would otherwise be lost to the atmosphere. Sources within the CPF where cooling systems are utilized include:

- heat exchangers upstream of the FWKO (Section B.5.2.2);
- heat exchangers downstream of the FWKO (Section B.5.2.3);
- heat exchangers downstream of the treaters (Section B.5.2.5);
- heat exchangers along the return flow line between the BFW tank and boilers (Section B.5.7); and
- condensed vapour cooling points within the produced gas recovery system (Section B.5.8.2).

The recovered heat will be used to heat various process streams such as combustion air preheat for the boilers, the boiler feed water, and building heaters. Any surplus heat will be rejected to the atmosphere via the glycol air cooler. Any minor amounts of glycol-water solution lost in the closed system loop are topped up from the glycol storage tank. Glycol heater exhaust stack height is provided in Table B.5.1.1.

B.5.11 Above Ground Interconnecting Pipeline System

Above ground interconnecting pipeline systems run along the utility corridor and connect the well pad facilities to the CPF. The pipelines within these corridors will consist of:

- liquid emulsion from the well pads to the CPF;
- vapours from the well pads to the CPF;
- high pressure steam from the CPF to the well pads; and
- fuel gas supply from the CPF to the well pads.

B.5.11.1 Emulsion Gathering System

Group separator emulsion pumps will provide the required pressure to transport the liquid emulsion to the CPF for processing.

B.5.11.2 Vapour Gathering System

Sub-surface reservoir pressure will provide the pressure required to free flow the vapour back to the CPF for processing.

B.5.11.3 Steam Distribution System

Steam will be delivered from the CPF (Section B.5.7) to the well pads via high pressure above ground steam lines and will be distributed at the pads to each well pair via a manifold building. A series of pressure letdown valves in the manifold building will be utilized to reduce the steam pressure to ensure the maximum allowed reservoir injection pressure is not exceeded. Each well pad will be equipped with an automatic shut off valve to ensure that this pressure is not exceeded. Road and wildlife crossings are included in the current design. Further geotechnical and environmental work on the site will determine the optimum crossing locations.

The steam generators are designed to deliver high quality (~ 99.5%) steam at the generator outlet. In order to ensure the steam condensate contained in the steam distribution system does not flow to only one injection well, appropriate flow splitters will be utilized within the distribution and manifold systems to provide an even distribution of the steam condensate throughout the injection wells.

Utility steam for miscellaneous heating uses, when required, will be supplied at each pad from a letdown station on the high pressure supply line. It will be used to preheat cold production lines by bleeding steam into the production lines.

The expected volumes of steam being bled off will be a maximum of 50 m^3/d (intermittent) and will be measured in the main header by steam flow meters.

B.5.11.4 Gas Distribution

A gas line to provide fuel gas to each of the well pads will be installed in the above ground pipeline corridor. This fuel gas is required to operate the possible sub-surface artificial lift system, and for utility services.

B.5.12 Electrical Power

The installed power operating load for the Project is approximately 7.8 megawatt (MW) for the existing site (train 1) and 20 MW for the expansion (train 2). A 13 MW natural gas fuelled combustion turbine-generator and heat recovery steam generator (HRSG) plant will supply the power requirements for the existing CPF train 1 and Pod One. Connacher plans to install a 22 MW turbine and HRSG plant to supply the power requirements for the expansion. In addition, heat recovered from the turbine exhaust will be used to make steam for SAGD operations. As the limiting factor for the facility's steam generation capability is the water treatment process, any steam produced by the cogeneration system will offset load from the primary steam generators. This Cogeneration facility will provide the SAGD facility with a reliable and cost effective source of thermal and electric energy. The steam provided by the HRSG is approximately 10% of the boilers capacity. When the HRSG is running the boilers will be turned down to 90% of their capacity. The Cogeneration facility will initially serve only Connacher operations, however as infrastructure develops in the area, the possibility exists that the facility will be connected to the grid. In such eventuality, separate regulatory approval processes will be undertaken. This possibility has been accommodated in the design of the cogeneration facility.

Natural gas is and will continue to be supplied from TCPL via pipeline. No produced gas will be supplied to the turbine generators. Boiler feed water will be supplied from the main boiler feed water system. The overall Cogeneration thermal efficiency will be approximately 78%.

Distribution of power from the main facility to the various production pads and make-up water wells will use an overhead 25 kV power line. Power line routing will follow the access roads or gathering pipelines whenever feasible.

Energy balances for the Project are provided in Table B.6.2.1.

B.5.13 Emergency Power

In the event of failure of internally generated power supply, critical plant loads will derive electricity from an emergency power system. This consists of a combination of a standby generator system for critical 480 V loads plus battery-backed uninterrupted power supplies (UPS) for critical 24 VDC and 120 VAC loads, such as the plant control systems and computer systems.

The diesel powered standby generator system will not be sized to support normal plant operation; it will have a maximum load capacity of approximately 5 MW. The diesel storage tank incorporated in the generator skid will supply fuel to the generator.

Critical 480 V loads will include key plant utility systems such as instrument air compressors and heat medium pumps as well as 480 V to 120/208 V transformers feeding critical lighting and electric heat tracing loads.

The plant control systems and associated computer loads will be UPS supplied as detailed above, with a standby time of eight hours.

B.5.14 Sanitary and Potable Water System

A supply of potable water will be required for the construction camp, operations camp, and the administration and control room offices at the CPF. Water for sanitary uses such as showers and toilets is also required. The current system that is in place for Algar will continue to be used. Additional details of the sanitary and potable water system are provided in Section B.7.3.

B.5.15 Utility Steam

A small stand-alone steam generator provides low-pressure steam for utility purposes. Utility steam generator exhaust stack height is 8.5 m. Utility steam is used for wash-down stations in each building and supplemental process heat in oil and water processing.

B.5.16 Domestic Sewage

Domestic sewage will be directed through the sewer system to the existing and operating septic field.

B.5.17 Drain System

The facility will have a floor drain collection system. All buildings will be equipped with floor drains and a sump. Water used to wash down the floors and equipment as part of routine maintenance will be collected in the sumps and transferred by pump to an above ground "floor drain tank". Liquids from the tank are transferred back to the waste oil storage tank and returned to the process (Section B.5.4).

B.5.18 Compressed Air System

Both the CPF and the well pads will have their own compressed air system. The system will be provided from a conventional instrument air compressor package that provides air at nominally 862 kPag and a dew point of -40°C. The air compressors will be electric powered.

B.5.19 Fire and Gas Detection

Each building will be equipped with lower explosive limit (LEL) and/or H_2S detection heads. In those areas, where there is potential for fire, fire detection heads will also be installed.

B.5.20 Chemical Use

Table B.5.20.1 lists the approximate annual quantities of chemicals used for the Project.

Table B.5.20.1 Chemical Use		
Item	**Rate per year Train 1 (existing)**	**Rate per year Train 2 (expansion)**
Water Treatment		
Caustic Soda (50% NaOH Solution)	365 m^3	1168 m^3
Anti foam	25 m^3	80 m^3
Scale Inhibitor	55 m^3	176 m^3
Boiler Chemicals		
Phosphate Dispersant	61.3 m^3	196 m^3
Oxygen scavenger	3.2 m^3	10 m^3
Filming Amine	15.3 m^3	49 m^3
Primary Separation		
De-emulsifier	33.9 m^3	80 m^3
Reverse emulsifier	119 m^3	286 m^3
Polymer	8.7 m^3	21 m^3

B.6 MATERIAL AND ENERGY BALANCE

B.6.1 Material Balance

B.6.1.1 Water

The water use for the Pod One, Algar and Algar Expansion Projects is provided in Table B.6.1.1 and is shown on Figure B.6.1-1. The water balance assumes reservoir losses of 5% when the CPF is operating in steady state conditions. Water losses to the reservoir are expected to be high initially in the warm up phase and reducing as the reservoir heats up.

Table B.6.1.1 Water Balance For Great Divide SAGD Expansion Project

	Pod One m^3/day	Algar			
		Existing m^3/day	**Expansion m^3/day**	**Total m^3/day**	**Total m^3/day**
Water Balance: Field					
100% quality steam to field	4,300	4,800	15,263	20,063	**24,363**
Total water to SAGD wells	4,300	4,800	15,263	20,063	**24,363**
Water loss to reservoir (5%)	215	240	763	1,003	**1,218**
Produced water from wells	**4,085**	**4,560**	**14,500**	**19,060**	**23,145**
Water Balance: Oil Treatment					
Produced water from field	4,085	4,560	14,500	19,060	**23,145**
Water losses to sales oil	10	10	25	36	**46**
Water losses in Oil Treatment (trucked-out slop, de-sand, etc.)	36	36	86	122	**157**
Water losses to fuel gas	3	3	8	11	**14**
De-oiled water to water treatment	**4,036**	**4,511**	**14,381**	**18,892**	**22,927**
Water Balance: Evaporator					
De-oiled water from oil/water process	4,036	4,511	14,381	18,892	**22,927**
Steam generator blow down recovery	133	148	472	621	**753**
Evaporator vent recovery	84	94	299	393	**478**

Table B.6.1.1 Water Balance For Great Divide SAGD Expansion Project

	Pod One m^3/day	Algar			
		Existing m^3/day	**Expansion m^3/day**	**Total m^3/day**	**Total m^3/day**
Crystallizer vent recovery	-	15	76	91	**91**
Crystallizer distillate recovery	-	183	910	1,093	**1,093**
Process makeup water	**460**	**309**	**784**	**1,093**	**1,553**
Total water into Evaporators	**4,713**	**5,260**	**16,922**	**22,183**	**26,895**
Evaporator sump loss for offsite processing	195	-	-	-	**195**
Evaporator sump loss to crystallizer	-	218	888	1,106	**1,106**
Evaporator vent loss	84	94	299	393	**478**
Evaporator distillate as boiler feedwater	**4,433**	**4,948**	**15,735**	**20,683**	**25,117**
Water Balance: Crystallizer					
Evaporator sump to crystallizer	-	218	888	1,106	**1,106**
Receipts from offsite evaporator brine	-	-	195	195	**195**
Total crystallizer inlet volume	-	218	1,083	1,301	**1,301**
Crystallizer Vent	-	15	76	91	**91**
Crystallizer concentrate loss (offsite disposal)	-	20	98	117	**117**
Crystallizer distillate recovery	-	183	910	1,093	**1,093**
Water Balance: Steam Generation					
Evaporator distillate as boiler feedwater	4,433	4,948	15,735	20,683	**25,117**
Steam generator blow down recycle	133	148	472	621	**753**
100% quality steam to field	4,300	4,800	15,263	20,063	**24,363**
Make-up Water Summary					
Utility makeup water	5	5	25	30	**35**
Process makeup water	460	309	784	1,093	**1,553**
Contingency (25%)	116	79	202	281	**397**
Total Makeup water required	581	393	1,011	1,404	**1,985**
ERCB Water Recycle Formula (steam-makeup)/(produced)	0.91034	0.96656	0.98289	0.97898	0.96687

A produced water recycle rate up to 97% is expected requiring an average of 1,000 m^3/d of fresh water for train 2, and a total of 2,000 m^3/d for steady state of the entire operation. A 25% contingency has been added to this scenario. Makeup water volumes and source requirements are respectively discussed in Section B.7.1 and Section B.7.2.

The water use requirements for the entire life of the Project have been provided on an annualized basis in Table B.6.1.2.

Table B.6.1.2 Project Life Cycle Water Balance Summary										
	Oil Production		Steam Injection		Reservoir Retention					ERCB Water
	bbls/day	m^3/day	m3/day	SOR	%	m^3/day	Returns	Losses m^3/day	Makeup m^3/day	Recycle
2010	12,242	1,946	6,807	3.50	5.0%	340	6,467	(664)	664	0.950
2011	16,092	2,559	8,069	3.15	5.0%	403	7,666	(633)	633	0.970
2012	18,160	2,887	9,253	3.20	5.0%	463	8,791	(638)	638	0.980
2013	32,575	5,179	20,949	4.04	5.0%	1,047	19,901	(1,366)	1,366	0.984
2014	40,442	6,430	24,172	3.76	5.0%	1,209	22,963	(1,576)	1,576	0.984
2015	43,409	6,902	24,350	3.53	5.0%	1,218	23,133	(1,588)	1,588	0.984
2016	44,918	7,142	24,228	3.39	5.0%	1,211	23,017	(1,580)	1,580	0.984
2017	42,054	6,686	24,451	3.66	5.0%	1,223	23,229	(1,594)	1,594	0.984
2018	40,892	6,502	24,465	3.76	5.0%	1,223	23,242	(1,595)	1,595	0.984
2019	43,532	6,921	24,241	3.50	5.0%	1,212	23,028	(1,580)	1,580	0.984
2020	40,747	6,479	24,206	3.74	5.0%	1,210	22,996	(1,578)	1,578	0.984
2021	40,336	6,413	24,546	3.83	5.0%	1,227	23,318	(1,600)	1,600	0.984
2022	40,926	6,507	24,423	3.75	5.0%	1,221	23,202	(1,592)	1,592	0.984
2023	40,318	6,410	24,459	3.82	5.0%	1,223	23,236	(1,595)	1,595	0.984
2024	39,044	6,208	24,353	3.92	5.0%	1,218	23,135	(1,588)	1,588	0.984
2025	38,276	6,086	24,522	4.03	5.0%	1,226	23,296	(1,599)	1,599	0.984
2026	34,913	5,551	19,105	3.44	5.0%	955	18,150	(1,246)	1,246	0.984
2027	26,924	4,281	16,198	3.78	5.0%	810	15,388	(1,056)	1,056	0.984
2028	22,329	3,550	12,814	3.61	5.0%	641	12,173	(835)	835	0.984
2029	16,442	2,614	8,627	3.30	5.0%	431	8,196	(562)	562	0.984
2030	12,096	1,923	7,374	3.83	5.0%	369	7,005	(481)	481	0.984
2031	7,906	1,257	3,436	2.73	5.0%	172	3,264	(224)	224	0.984
2032	2,403	382	622	1.63	5.0%	31	590	(41)	41	0.984
2033	614	98	316	3.24	5.0%	16	300	(21)	21	0.984
2034	339	54	57	1.05	5.0%	3	54	(4)	4	0.984
2035	468	74	169	2.27	5.0%	8	161	(11)	11	0.984
2036	86	14	-		5.0%	-	-	-	-	0.984

B.6.1.2 Hydrocarbon Liquids

During peak operation, 18,316 m^3/day of production fluids will be delivered from the well pads to the inlet group separator at the plant. Of the total volume, approximately 3816 m^3/day is bitumen and 14,500 m^3/day is water, assuming a 5% loss of steam to the reservoir. The bitumen is blended with 929 m^3/d of diluent in order to treat the bitumen to meet the 0.5% BSW (Basic Sediment and Water) sales specification. A total volume of 4,889 m^3/day of dilbit will be trucked from the CPF gate. All vapours within the process are cooled to condense water and hydrocarbons, which are separated and returned to the bitumen extraction process. The remaining hydrocarbon gas is combined into the fuel gas stream and consumed in the SAGD process.

B.6.2 Energy Balance

The energy balance for the train 2 expansion is provided in Table B.6.2.1.

Table B.6.2.1 Facility Energy Balance

	Pod One	Algar Existing	Algar Expansion	Algar Total	Project Area Total
Total Energy IN					
Bitumen from Wells					
Bitumen Production (m3/d) =	1600	1600	3816	5416	7016
Bitumen Density (kg/m3)	1023.6	1023.6	1023.6	1023.6	1023.6
Bitumen Production (t/d) =	1,637.8	1,637.8	3,906.1	5,543.8	7,181.6
Bitumen HHV (kJ/kg) =	46,000	46,000	46,000	46,000	46,000
Chemical Energy Flow (GJ/d) =	75,337	75,337	179,679	255,016	330,353
Reservoir Gas					
Reservoir Gas Volume (Sm3/d dry) =	16,000	16,000	38,160	54,160	70,160
Reservoir Gas HHV (MJ/Sm3) =	14.36	14.36	14.36	14.36	14.36
Chemical Energy Flow (GJ/d) =	230	230	548	778	1,007
Diluent Feed					
Diluent Rate (m3/d)	572	572	936	1,508	2,080
Diluent Density (kg/m3)	700	700	700	700	700
Diluent from Truck (t/d) =	400.40	400.65	655.20	1,055.85	1,456.25
Diluent HHV (kJ/kg) =	47,677	47,677	47,677	47,677	47,677
Chemical Energy Flow (GJ/d) =	19,090	19,102	31,238	50,340	69,430
Natural Gas					
Fuel Gas for CPF (Sm3/d) =	282,426	276,527	965,218	1,241,745	1,524,171
Fuel Gas HHV (MJ/Sm3) =	37	37	37	37	37
Fuel Gas for Cogen (GJ/d) =	0	3,650	4,745	8,395	8,395
Chemical Energy Flow (GJ/d) =	10,450	13,881	40,837	54,719	65,168
Electricity Import					
Electrical Power (MW) =	8.00	0.00	0.00	0.00	8.00
Electrical Power (GJ/d) =	691	0	0	0	691
Total Energy OUT					
Saleable Products (Dil-Bit)					
Dil-Bit Product (t/d dry) =	2,038	2,038	4,561	6,600	8,638
Dil-Bit HHV (kJ/kg) =	46,329	46,330	46,241	46,268	46,283
Chemical Energy Flow (GJ/d) =	94,427	94,439	210,917	305,356	399,782
Electrical Export					
Electrical Power (MW) =	0.00	4.85	0.00	4.85	4.85
Electrical Power (GJ/d) =	0	419	0	419	419
Total Energy IN (GJ/d) =	105,798	108,550	252,301	360,852	466,649
Total Energy OUT (GJ/d) =	94,427	94,858	210,917	305,775	400,201
Energy Efficiency (%) =	89.25	87.39	83.60	84.74	85.76

B.6.2.1 Fuel Gas

The major users of fuel gas in the plant are the steam generators, turbine- generators, glycol heater, and blanket gas to the storage tanks. The majority of this fuel gas will be supplied from a third party pipeline system.

Annual fuel gas consumed compared to the amount of energy produced for the train 2 expansion is presented in Table B.6.2.1.

B.6.2.2 Produced Gas

Minor volumes of production gas (mostly methane) are released as the SAGD process heats the bitumen in the reservoir. High temperatures associated with steam operations can also lead to the presence of non-condensable carbon dioxide and hydrogen sulphide through the aquathermolysis process. These gases are a small component of the total vapour, which is processed in the CPF. Publicly available industry data based on empirical and laboratory research estimates the volume of solution and non-condensable gases at 6 m^3 of gas per m^3 of produced bitumen. From Connacher's Pod One experience a design rate of 10 m^3 of gas per m^3 of produced bitumen has been considered. The composition of this gas is expected to be 50 to 60% methane; 40 to 45% carbon dioxide; and up to 1.6% hydrogen sulphide.

At the full bitumen production rate of 3,800 m^3/d, the produced solution and non-condensable gas rate is estimated at 38,160 m^3/d (10 m^3 gas per m^3 bitumen). This gas stream is cooled to remove any water vapour and then is combined with the main fuel gas to be burned in the steam generator. The production gas makes up approximately 3% of the total fuel gas requirement.

Annual production gas consumed compared to the amount of energy produced for the train 2 expansion is presented in Table B.6.2.1.

B.6.2.3 Electricity

The main power consumption in the CPF is the vapour compressors associated with the produced water treatment system and boiler feed water (Section B.5.6). At peak operations, the power load from the CPF expansion train 2 is estimated at near 20 MW (Table B.6.2.2).

Table B.6.2.2 Energy Input to Produced Energy Ratio

Item	Units	GJ/d
Fuel Gas	1,173,234 m^3/d	43,996
Produced Gas	38,160 m^3/d	859
Electrical Power	20 MW	1728
Sub Total		**46,583**
Bitumen	3,816 m^3/d	166,057
Energy produced to energy input ratio		3.6

Assumptions:60% of the production gas is methane, the remainder is non combustible

- Fuel gas and production gas both have an average heat value of 0.0375 GJ/m^3
- The HHV (higher heating value) of the bitumen is assumed to be 0.043 GJ/kg at a density of 1012 kg/m3
- Electricity power conversion is 86.42 GJ/d per MW

Annual electrical consumed compared to the amount of energy produced for the Train 2 Expansion Project is presented in Table B.6.2.1.

B.7 WATER MANAGEMENT

Regulatory guidelines for process water recycle are included in four main guides:

- ERCB Guide IL89-05 "Water Recycle Guidelines and Water Use Information";
- ERCB-AENV Guide 89-AA "Water Recycle Guidelines and Reporting of Water Use Information for In-Situ Oil Sands Facilities in Alberta";
- ERCB Bulletin 2006-11 March 28, 2006, "Water Recycle, Reporting, and Balancing Information for In Situ Thermal Schemes"; and

- ERCB Directive XX February 2009 (Draft) – "Requirements for Water Measurement, Reporting, and Use for Thermal In Situ Oil Sands Schemes".

The guidelines have a goal of maximizing water recycling to reduce the freshwater requirements and wastewater disposal volumes associated with oil sands developments. All in-situ operators with freshwater requirements exceeding approximately 500,000 m^3/year (500 dam^3/year) are required to recycle produced water.

The water management plan proposed by Connacher will re-cycle, as much as possible, the steam condensate and water used in the SAGD process. As described in the produced water treatment system (Section B.5.6), a produced water re-cycle rate as high as 97% is possible. If achieved this is a near zero liquid discharge system.

B.7.1 Volume of Process Make Up Water

Table B.6.1.1 lists the water balance for Pod One, Algar and Algar expansion (train 2) of the CPF and reservoir during normal full capacity operations. The source makeup water requirements are predicted to be around 2,000 m^3/d. Water losses are comprised of:

- losses in the reservoir;
- brine off the crystallizer;
- utility water losses; and
- water entrained in sales oil.

As the individual SAGD well pairs progress through their productive life cycle, the balance of water injected to the water produced varies. During initial circulation of the well pairs, up to 20% of the water injected is expected to be retained in the reservoir. The amount of retained water is expected to decrease to about 5% of the water injected during normal SAGD well pair production operations. As the well pair nears the end of its productive life, the steam injection volume is decreased and eventually eliminated. During this period, the well remains in production resulting in a more water produced than injected.

The total volume of water required for the expansion Project (train 2) is approximately 15,000 m^3/d (based on a SOR of 4.0 x 3,800 m^3/d for production) which includes produced water. The total volume required for the combined Pod One, Algar and the train 2 is approximately 24,000 m^3/d. The estimated make-up water required for steady state operations for train 2 is approximately 1400 m^3/d and 2,000 m^3/d for the entire operation.

B.7.2 Source of Process Make Up Water

Source water for the Project will come from water wells drilled into the Lower Grand Rapids Formation. Source water will be pumped from water wells located near the CPF to the existing fresh water storage pond. The source pond allows for water storage and provides some flexibility if problems occur with the source wells.

Connacher has approved water allocations under the *Water Act* from Alberta Environment for Pod One (290,000 m^3/yr) and Algar (330,000 m^3/yr). Connacher is requesting an additional 480,000 m^3/yr water allocation from the same formation for the expanded SAGD production (train 2).

B.7.3 Sanitary and Potable Water Supply Requirements and Source

A supply of sanitary and potable water is required for the construction camp, operations camp, and the administration and control room offices at the central processing facility. Drinking and cooking water is currently trucked in from an offsite source and will continue in this manner with the expansion. Water for sanitary uses such as showers and toilets will also continue to be trucked in for the Project.

The planned 400-man construction camp for the train 2 expansion would require an estimated 40 m^3/day and 6 m^3/day respectively for the sanitary and potable water supply when the camp is at full capacity. This camp will be in operation for about a 24 month time period. During ongoing operations, the estimated daily sanitary and potable water usage is estimated at 5 m^3 and 2 m^3 respectively.

B.7.4 Drainage Management

Site preparation will provide adequate drainage away from storage tanks, equipment, skids, buildings and pipe racks and direct it towards designated storm water retention ponds. The site preparation has been completed as part of the train 1 construction and contains a storm water retention pond. The CPF will not be expanded beyond the current footprint.

B.7.4.1 Central Processing Facility

All storage tanks will be equipped with secondary containment and leak detection to minimize the occurrence of product leaks and subsequent contamination to the environment.

Surface water run-off from the plant site will be directed the storm water retention pond located on the north side of the CPF. The retention pond was constructed in accordance with ERCB Directive 55 regulations. All surface runoff will be returned to the CPF stormwater pond and released into the surrounding watershed receiving waters. Prior to discharge, the water will be tested and released in accordance with the terms and conditions of the operating approval.

B.7.4.2 Well Pads and Roads

All well pads and roads will be constructed in a manner in which erosion from surface water runoff will be minimized. This will be achieved utilizing appropriate collection areas and flow barriers where necessary. Ditches will be designed to avoid ponding of water along the road surface. Flows will be maintained across drainages and wetlands with the appropriate use of culverts.

B.7.5 Waste Water Disposal

B.7.5.1 Processed Wastewater

A waste stream of concentrated brine from the crystallizer process will be trucked or pipelined to an approved disposal facility. A disposal volume of 100 t/d is expected.

B.7.5.2 Sewage Treatment

The sewage treatment for the Project currently is operational and is processed by the underground septic tanks and field that was installed as part of the Algar (train 1) construction.

B.8 OFFSITE CONNECTIONS

B.8.1 Transportation

The Project is located approximately 70 km south of Fort McMurray. Road access to the Project will use Highway 63 south of Fort McMurray then east on an all weather road that was completed as part of the Algar train 1 construction. Additional access points off Highway 63 are not required. The existing turn out lanes on Highway 63 allow traffic to turn off and enter the highway safely have been deemed adequate by Alberta Transportation.

B.8.1.1 Construction

Algar train 2 facility construction philosophy will be to pre-build most of the equipment packages, piping modules, piping spools, support modules, walkways, tanks, motor control centers, etc., in the Calgary-to-Edmonton corridor. This construction philosophy will minimize field construction. Field construction will be divided into categories and awarded to numerous contractors to limit exposure to labour disruptions and to allow hiring outside of the Fort McMurray large/mega project work pool. The mechanical contractor will be considered the primary contractor. Contractors will be hired on fixed rate or a lump sum basis.

All Contractors will be supplied camp accommodations by Connacher at the Algar construction camp approximately 4 km west of the Algar facility.

B.8.1.2 Operations

All operations staff will be supplied camp accommodations by Connacher at the Algar operations camp approximately 0.5 km east of the Algar construction camp.

B.8.1.3 Algar Airstrip

Historically, the Algar Airstrip was used by Forestry to service the fire tower that was on site. 1n 1996 the tower was badly burned in a fire and became unserviceable. By this time the strip was no longer used by forestry but remained their disposition. Connacher began discussions with Forestry and took over the strip.

To date, the airstrip has been improved to some degree. The original access road from Highway 63 has been removed per a requirement from the Department of Transportation. The new access road coming in from the south has been fully established. As well, part of the apron and the office area have had the civil dirt work completed.

Currently the existing airstrip is sufficient to allow small craft to use it in summer and in winter under good conditions.

As Connacher grows, the amount of personnel required to run the site will reach critical mass. This is anticipated to occur when the expansion plans are complete in approximately 2013 and the manpower curve shows the strip to be an economical addition to the project. At this time, the strip would be upgraded to allow Dash 8 type of craft to use the airstrip.

B.8.2 Electrical Supply

A 22 megawatt (MW) natural gas fuelled combustion turbine-generator and heat recovery steam generator plant is also planned for at the Algar train 2. The power plant (Cogen) would provide power for the SAGD facility’s overall operations and supplemental steam for the SAGD process. Excess power will be sold to the provincial power grid through a planned connection with ATCO Electric’s existing power transmission system.

The Cogen provides the train 2 facility with an on-site reliable and cost effective source of thermal and electric energy. The type of Cogeneration facility proposed is utilized at other SAGD and industrial facilities in Alberta and worldwide since it is an eco-efficient means to co-produce steam and electricity. The SAGD facility’s initial electrical load requirement will be approximately 20MW. A 22MW (iso rating) Solar Turbines Titan 250 generator set, a HRSG, motor control centre, electrical switch gear and an interconnection to the local electric utility will provide the basis for the project.

B.8.3 Fuel Gas Supply

Natural gas will be supplied from TCPL via the existing 219 mmOD pipeline with an MOP of 10,200 kPa. This is an existing pipeline that runs to Algar train 1.

B.8.4 Fresh Water Supply and Storage

Fresh potable water used at the office for the operations staff will continue be trucked in to site and unloaded at the fresh water storage located at the office as it currently is.

B.8.5 Diluent and Oil Sales Pipelines

Future 324 mmOD oil sales pipeline and future 219mmOD Diluent inlet pipeline are being considered and details of the design have not been finalized.

B.9 HEALTH, SAFETY, AND ENVIRONMENTAL MANAGEMENT

B.9.1 Policies

Connacher is a member of the Canadian Association of Petroleum Producers (CAPP), and is committed to CAPP's Stewardship program. Stewardship is a commitment to responsible resource development and continuous improvement. It is an integrated approach that instils sound planning and operating practices to ensure continuous improvement in environmental, health and safety and social performance. Connacher believes in promoting mutually beneficial relationships and open and honest reporting of its performance in those areas.

The Great Divide SAGD Expansion Project will include the existing Great Divide (Pod One) and the Algar Projects, and additional project development areas. These Projects already have, or will have, in place, substantial procedures, policies and action plans to address all Health, Safety, and Environmental Management issues. These procedures, policies and action plans will be incorporated in to the Project and expanded to cover any and all additional requirements, and will capture learning's from both of these previous projects.

Connacher will provide responsible management for the Project by ensuring that health, safety, and environmental policies and procedures are established and implemented. All management staff will be familiar with all policies and procedures and employees, contractors and consultants under their direction will receive proper instruction on same through on-site training programs. By following this approach, the Project will be developed and operated in a professional, safe, and responsible manner.

B.9.1.1 The Environment

Protection and preservation of the environment is a fundamental belief of the Company. Comprehensive measures will be reviewed and implemented to mitigate the occurrence of environmental issues in the design and operation of the Project.

Employees, contractors and consultants will be expected to operate equipment according to vendor recommendations and procedures. Workers will be trained to manage and respond to operating situations that may impact the environment by expeditiously determining the cause and remedying the problem, to the extent of shutting in a process to control the situation.

Preparation and adherence to environmental standard operating procedures and practices (SOPs) will form part of the guiding operating principles throughout the life of the Project. All employees, contractors and consultants will be advised of these environmental work procedures and practices with daily and routine activities being managed according to same.

Appropriate signage, markings and other designations will be implemented to guide and inform personnel with respect to environmental considerations. With knowledge**,** training and understanding of the situation, these directions, along with applied procedures and practices will minimize the risk of occurrence of an undesirable incident.

Continuous learning, training and improvement will be ongoing throughout the life of the Project to ensure operating staff are current with knowledge and information on regulatory issues and environmental considerations associated with development and operation of the Project.

Environmental monitoring will be reviewed by designated Connacher personnel to ensure compliance with environmental approval requirements. Ongoing assessments and audits will be carried out throughout the life of the Project on a regular basis to ensure Connacher's objectives with respect to environmental stewardship have been met.

B.9.1.2 Health and Safety

Connacher is committed to conducting operations in a safe and environmentally sound manner. In support of this commitment, Connacher has developed a General Policy on Health, Safety and the Environment.

In order to fulfill this commitment, Connacher has developed a Safety Program to ensure its operations comply with this policy. The program includes a Management Plan for implementing the Program. This manual is intended to present that Plan and to provide management, employees and contractors with the tools, information and references they need to carry out that Plan.

It is Connacher's practice to provide each user of this manual (i.e. operators, supervisors and contractors) with training in its use. This training should be considered as the primary orientation of the new personnel to Connacher's operations.

Complementary documents, tools and training include Connacher's:

- Health, Safety, & Environment Handbook;
- Emergency Response Plan(s); and
- Supervisory Training.

This manual in its entirety should always be considered a work-in-progress. All users are encouraged to provide suggestions to the Regulatory, Health, Safety and Environmental Departments' for improvements to its content and format.

The development of this Safety Program, together with supporting training, will help all Connacher's staff, contractors and supervisors to:

- make maximum use of the combined resources of Connacher, government agencies, and other outside services to:
- assist with orienting, informing, guiding and motivating Company employees and contractors;
- implement policies, procedures, practices and standards relating to Company operations;
- provide and maintain a safe working environment including tools, machines and equipment;
- maintain effective communication;
- ensure immediate, competent responses when handling and emergency; and

- control work site hazards, thus minimizing the risk to Connacher employees, its contractors and the public.

All personnel directly involved with Connacher operations, including both Company and Contract personnel, are responsible for ensuring their activities are consistent with this manual.

B.9.2 Integrated Environmental Health and Safety Management Plan

Connacher will integrate environment, health and safety into all facets of the Great Divide Expansion Project. The objective of the management plan is to ensure compliance with Connacher's environmental and health and safety stewardship objectives. The program will be implemented through the following mechanisms.

- Progressive Project Management – Continual Improvement Process
- Loss Control and Environmental Compliance Program
- Emergency Response Plan
- Waste Management Plan
- Substance Release Controls and Monitoring
- Wildfire Response Plan
- Stakeholder Consultation

B.9.2.1 Progressive Project Management – Continual Improvement Process

The Progressive Project Management approach adopted by Connacher will be applied in three stages.

The first stage is carried out prior to development. Baseline conditions are evaluated and potential environmental and safety considerations identified. Where deemed appropriate, facility design and control requirements are modified so as to minimize any potential negative operating incidents.

The second stage involves monitoring and mitigating the potential environmental and safety incidents during operations in order to ensure the effects are prevented, minimized or mitigated. This program will make the necessary changes to the environment or safety programs so that any adverse effects can be halted with operating and mitigative procedures being altered or modified to address the effect.

The third stage occurs at abandonment to demonstrate that all environmental and safety liabilities have been removed from the site's remaining foot print. The site has been fully reclaimed and pre-disturbance capabilities returned.

B.9.2.2 Loss Control and Environmental Compliance Program

Designated Connacher personnel will act as the site custodian to ensure that environmental and safety operating procedures are regularly evaluated and if necessary altered to address any adverse effects that are occurring. The progressive project management - continual improvement process is an integral part of the Loss Control and Environmental Compliance Program.

B.9.2.3 Emergency Response Plan

As part of its operating procedures, Connacher will develop an emergency response plan that sets out procedures and identifies responsible personnel and third party support expertise to deal with emergency situations. The plan will specifically addresses alert levels, evacuation requirements, call down procedures and external emergency agency involvement.

Response equipment will be documented, kept current, and made readily available as a part of the emergency response plan.

The emergency response plan will address incidents such as:

- serious onsite injury to facility personnel, contractors, consultants, or members of the public;
- central processing facility shutdown;
- major equipment or instrumentation failure;
- major spills or releases to the environment;
- fire in or near facilities;
- security issues such as criminal acts, threats, or act of terrorism;
- loss of well control; and
- pipeline rupture.

The primary objectives of the ERP will be to limit the danger to facility personnel, the public, the environment and operating equipment.

B.9.2.4 Waste Management Plan

A waste management plan for the Project will be designed to effectively control waste by minimizing waste generation and the waste disposal required. The over-riding principles of the plan are to reduce, reuse or recycle. The waste management plan will routinely obtain feedback on the effectiveness of the plan and identify opportunities for continual improvement.

Waste management at the site will comply with the following waste management processes, procedures and guidelines including the EPEA Waste Control Regulation (AEP 1996). Practices will include:

- classifying, measuring and controlling waste generation;
- handling, storage, treatment and disposal;
- tracking and reporting;
- off-site disposal of DOW (dangerous oilfield waste) and non-DOW wastes as appropriate; and
- recycling as appropriate.

Waste management practices will meet or exceed the requirements of the ERCB. Specifically, these waste management requirements are outlined in both Directive 58 *(Oilfield Waste Management Requirements for the Upstream Petroleum Industry*) (EUB 1996a) and Directive 50 *(Drilling Waste Management)* (EUB 1996b). Directive 58 requires the preparation of an Annual Oilfield Waste Disposition Report summarizing the types and quantities of disposed oilfield wastes, the points of generation, and the disposal methods utilized.

All wastes will be disposed of in a responsible manner complying with all appropriate regulations and guidelines and in accordance with waste handling requirements contained in the expected EPEA Approval for the Project. Detailed waste disposal practices and procedures will be developed prior to the start of construction and operations and will be continuously reviewed upon throughout the life of the Project.

Wastes will be generated during two main stages of the proposed development, initially during construction and during the on-going operation for the life of the Project. Construction and development includes construction and operation of camps, construction of roads, expansion of the existing plant site (CPF), the addition of well pads, steam distribution lines and liquid transfer lines from the well pads to the CPF. Construction and development will extend over a period of about one year and the life of the project is estimated at 25 years.

Summaries of the wastes generated for each stage are shown in the Table B.9.2.1 including proposed storage locations, disposal sites, and disposal methods and where possible estimated annual quantities. There are no products that are listed in the National Pollutant Release Inventory, or listed at toxic substances in the Canadian Environmental Protection Act, or require further assessment.

Quantities of waste generated during operations have been estimated in the table by using process flow diagrams and material balance calculations, but the quantities of construction waste and camp waste have not been determined. These will be disposed of in approved disposal facilities on an as-generated basis.

Table B.9.2.1 Waste Management Plan

Waste Description	ERCB Waste Code*	Storage Location	Disposal Responsibility	Disposal Method	Annual Volume
Construction:					
Packing materials	DOMWST	Bin	Contractor	Incinerator/Recycle	As Generated
Cardboard	DOMWST	Bin	Contractor	Incinerator/Recycle	As Generated
Pallets	CONMAT	Bin	Contractor	Incinerator/Recycle	As Generated
Wood	CONMAT	Bin	Contractor	Incinerator/Recycle	As Generated
Scrap Metal	SMETAL	Bin	Contractor	Landfill/Recycle	As Generated
Glass	CONMAT	Bin	Contractor	Landfill/Recycle	As Generated
Paint	WPAINT	Bin	Contractor	Recycle	As Generated
Sand blast	CONMAT	Bin	Contractor	CLB LF**	As Generated
Insulation	CONMAT	Bin	Contractor	CLB LF**	As Generated
Welding rods	CONMAT	Bin	Contractor	CLB LF**	As Generated
Lubricants	LUBOIL	Drums	Contractor	Recycle	As Generated
Oil filters	FILLUB	Drums	Contractor	Recycle	As Generated
Cable Cutoffs	SMETAL	Bin	Contractor	Landfill/Recycle	As Generated
Construction – Camp					
Kitchen waste	DOMWST	Bins	Contractor	Landfill	As Generated
Cardboard	DOMWST	Bins	Contractor	Landfill/Recycle	As Generated
Containers	EMTCON	Bins	Contractor	Incinerator	As Generated
Septic Fluids	WSTMIS	Septic System	Contractor	Digestor/Contractor	As Generated
Operations – Drilling					
Drilling mud/cuttings	Various	Tank	Contractor	Recycle or MBC***	As Generated
Lubricants	LUBOIL	Drums	Contractor	Recycle	As Generated
Mud additives	Various	Bins	Contractor	Return or Recycle	As Generated
Scrap metal	SMATAL	Bins	Contractor	Recycle	As Generated
Pallets	CONMAT	Bins	Contractor	Landfill/Recycle	As Generated
Cement	CEMENT	Bins	Contractor	CLB LF**	As Generated
Solvents	Various	Drums	Contractor	Return or Recycle	As Generated
Mud sacks	EMTCON	Bins	Contractor	CLB LF**	As Generated
Operations – CPFs					
Filter: Glycol	FILGY	Bins	Swan Hills	Swan Hills	0.1 m^3
Filter: Raw Water	FILFWT	Bins	Owner	CLB LF**	0.5 m^3
Filter: Pressure	FILOTH	Bins	Swan Hills	Swan Hills	5.0 m^3
Filter: Oil removal	FILOTH	Bins	Swan Hills	Swan Hills	4.0 m^3
Ion exchange resins	IEXRES	Bins	Owner	CLB LF**	50.0 m^3
Filter Backwash Sludge/Liquid	WESTMIS	Tank	Owner	Recycle	
Boiler Blowdown	WSTMIS	Vessel	Owner	Recycle	

Table B.9.2.1 Waste Management Plan

Waste Description	ERCB Waste Code*	Storage Location	Disposal Responsibility	Disposal Method	Annual Volume
Water					
Process Blowdown Water	WSTMIS	Tank	Owner	Recycle	
Septic Fluids	WSTMIS	Septic System	Owner	Site septic field	800 m^3
Caustic	CAUS	Tank	Owner	Recovery	986 m^3/yr
Acid	ACID	Truck in as needed	Third Party	Return or Recycle	
Batteries	BATT	Bin	Owner	Recycle	
Containers: Drums/barrels	EMTCON	Bin	Owner	Return or Recycle	
Containers: herbicide	PSTCON	Bin	Owner	Return or Recycle	
Containers: pesticide	PSTCON	Bin	Owner	Return or Recycle	
Containers: biocide	EMTCON	Bin	Owner	Return or Recycle	
Filters: lube oil	LUBOIL	Bin	Third Party	Recycle	0.5 m^3/yr
Filters: produced oil	FILWWT	Bin	Swan Hills	Swan Hills	As Generated
Garbage: office paper	DOMWST	Bin	Owner	Landfill/Recycle	As Generated
Pallets	DOMWST	Bin	Owner	Landfill/Recycle	As Generated
Packing materials	DOMWST	Bin	Contractor	Landfill/Recycle	As Generated
Hydrotest fluids: methanol	METHNL	Tank	Contractor	Recycle	
Insulation	CONMAT	Bin	Contractor	CLB LF**	As Generated
Lab. Chemicals - spent	INOCHM/OR	Drums	Owner	Recycle	
Rags: oily	OILRAG	Bin	Owner	CLB LF**	As Generated
Sludge: Separators	SLGPRO	Tank	Owner	Recycle	In Produced Sand
Sludge: oil slop tanks	SLGHYD	Tank	Owner	Recover	In Produced Sand
Well Workover fluids	WNOFLD	Tank	Contractor	Bioremediation	As Generated
Operations – Camp					
Kitchen waste	DOMWST	Bins	Contractor	Landfill	As Generated
Cardboard	DOMWST	Bins	Contractor	Landfill/Recycle	As Generated
Containers	EMTCON	Bins	Contractor	Landfill/Recycle	As Generated
Septic Fluids	WSTMIS	Septic System	Contractor	Digestor	As Generated
Incinerator Ash	INCASH	Bin	Contractor	CLB LF**	As Generated

* ERCB Waste Codes – Waste Listings of EUB Directive 58 – Oilfield Waste Management Requirements for the Upstream Petroleum (EUB, 1996)
** CLBLF – Class II Landfill
*** MBC – ERCBs' and AENVs' Mix Bury Cover Requirements

B.9.2.5 Substance Release Monitoring

The two primary emission destinations from which emissions sources from the project can occur are air and water. Substance release monitoring will be carried out under the supervision of the onsite Project Manager. The types and volumes of project emission sources will be tracked and recorded as per the applicable regulations and operating approval conditions. The maintenance of pollution abatement and monitoring equipment will be an integral component of normal maintenance and operations of the facility.

B.9.2.6 Fire Control Plan

The fire control plan for the Project will address:

- the Project as a source of fire; and
- wildfire impact on the Project.

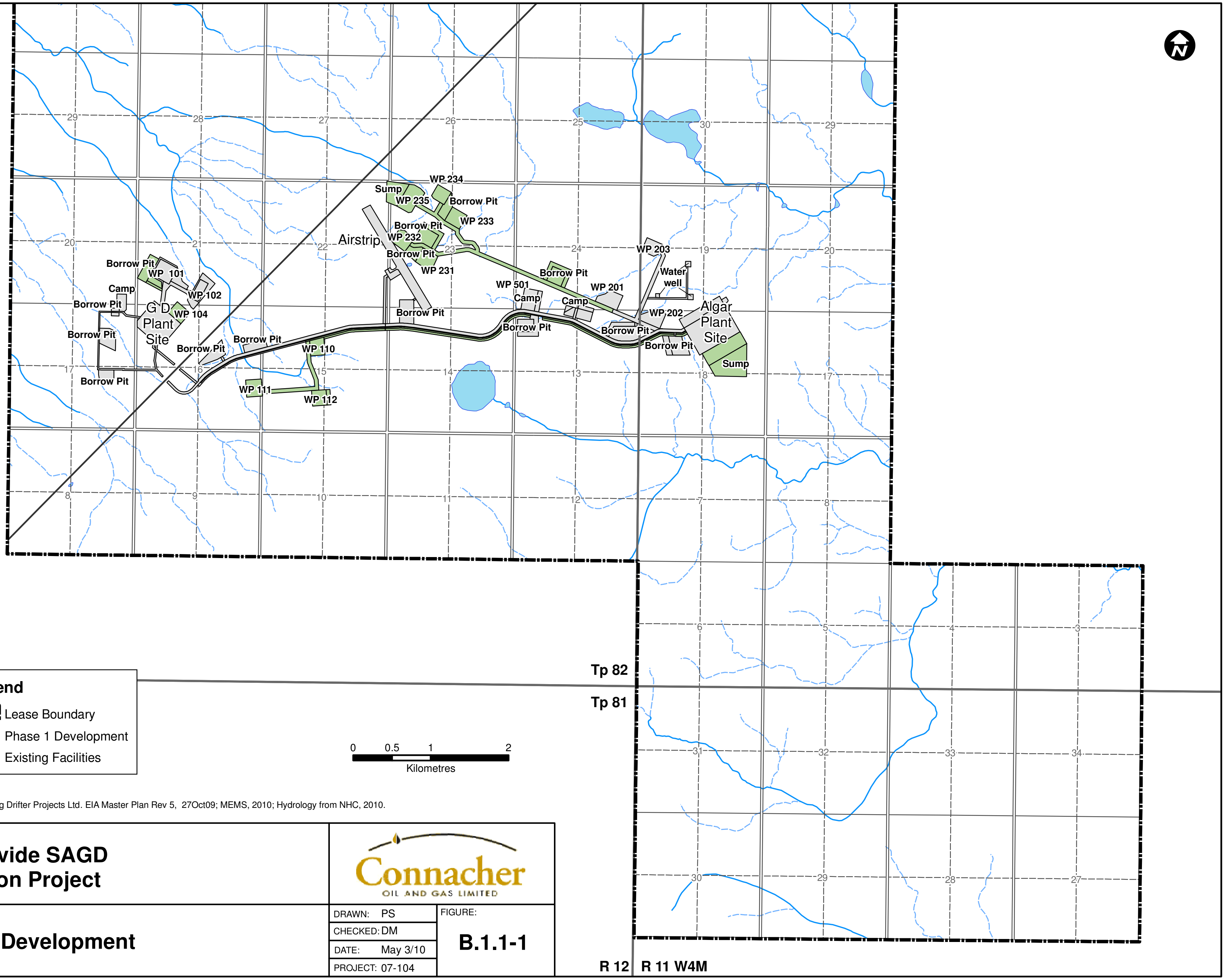
Potential sources of fire resulting from the Project include operations within the CPF, the electrical distribution system, flare system and steam piping. “Fire Eye” sensors capable of detecting open flame will be installed in critical areas of the CPF and well pads. In addition, combustible gas and smoke detectors will be located throughout the facility. All sensors will be tied into the process-control system to allow prompt response in the event of fire.

Plans for fire suppression during the operation of the Project will require a combination of wall-mounted and wheeled fire extinguishers located around the CPF and well pads. In addition, operators’ trucks will be outfitted with portable fire extinguishers.

Other fire reduction measures incorporated will include:

- use of non-combustible building materials;
- where deemed appropriate, absence of combustible ground cover;
- adequate setback of facilities from the surrounding forest;
- adequate building separation; and
- placement of fire blankets in strategic locations within the Project Area.

A wildfire control plan will be developed in consort with the Forest Protection Division of Alberta Sustainable Resource Development. It will describe the equipment and level of readiness that is present by Connacher at the Project to assist in wildfire control. It will also include maps of roads and accesses to Connacher’s lease area to provide valuable information for the local forest protection division. Forest Fire awareness training will also be added to the suite of training programs for Connacher employees.



Legend

- Lease Boundary
- Phase 1 Development
- Existing Facilities

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; MEMS, 2010; Hydrology from NHC, 2010.

PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

TITLE:

Phase 1 Development

DRAWN:	PS
CHECKED:	DM
DATE:	May 3/10
PROJECT:	07-104

FIGURE: **B.1.1-1**

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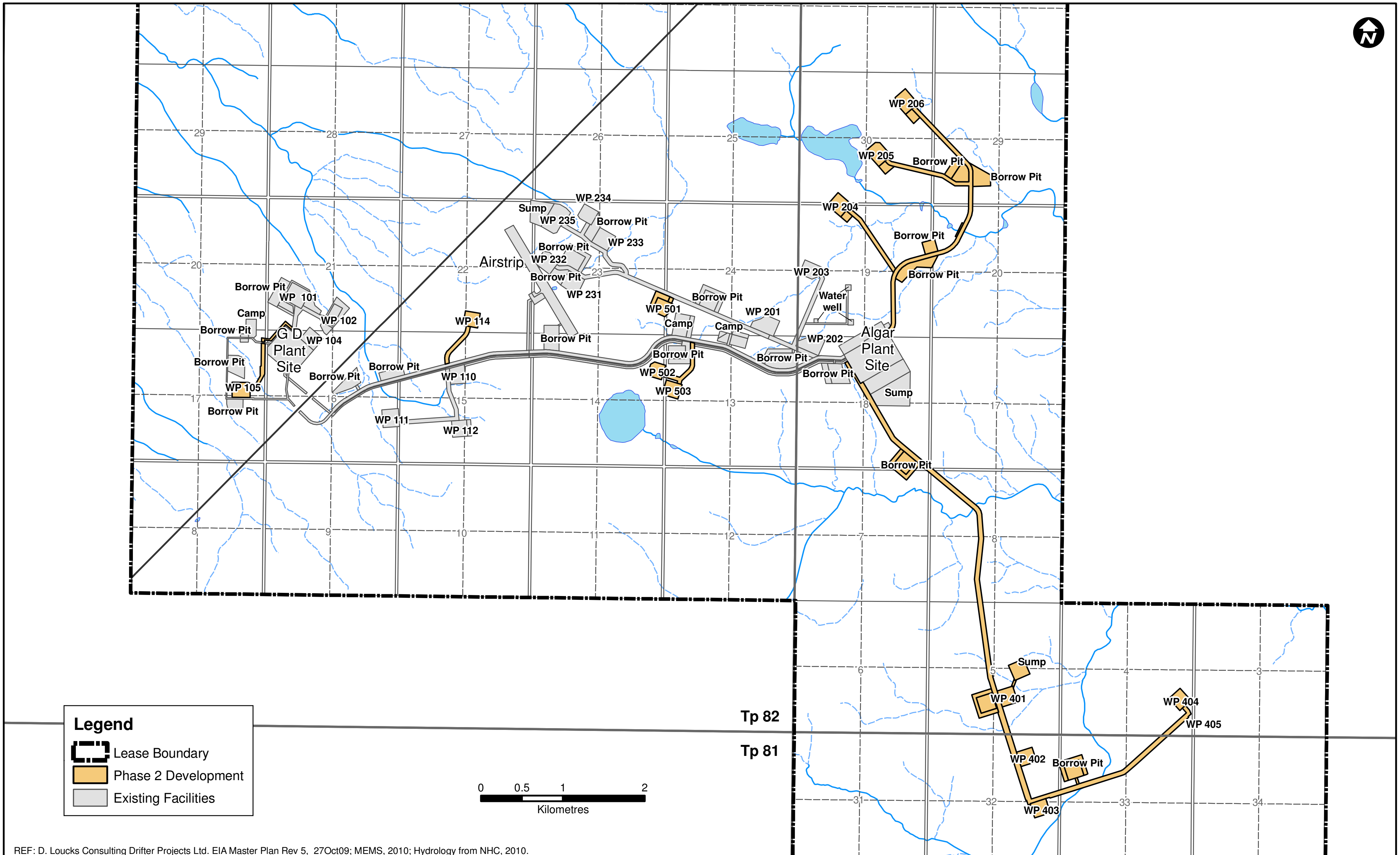

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; MEMS, 2010; Hydrology from NHC, 2010.

PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

TITLE:

Phase 2 Development

DRAWN: SL
CHECKED: DM
DATE: May 3/10
PROJECT: 07-104

FIGURE: **B.1.1-2**

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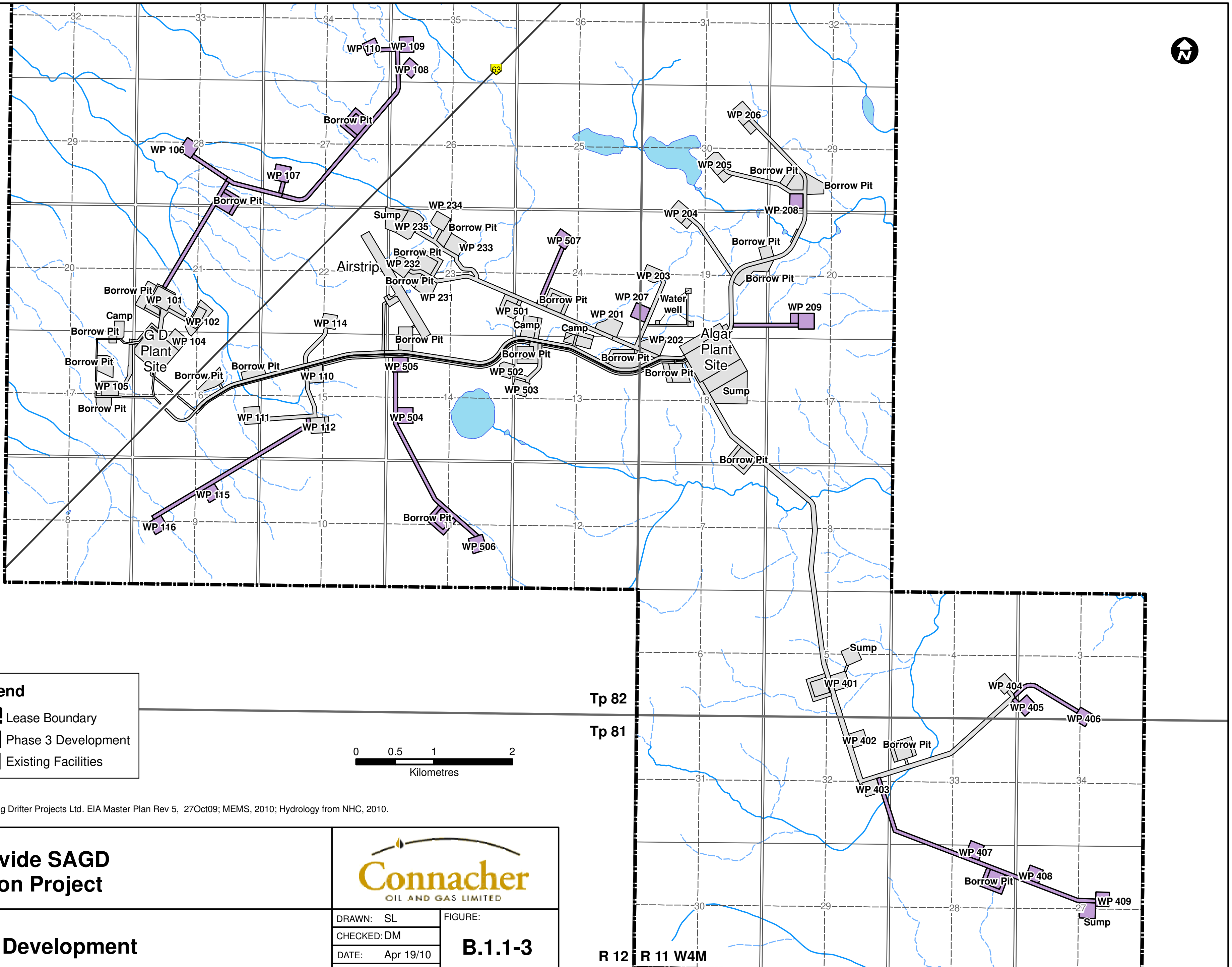


REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; MEMS, 2010; Hydrology from NHC, 2010.

PROJECT:

Great Divide SAGD Expansion Project

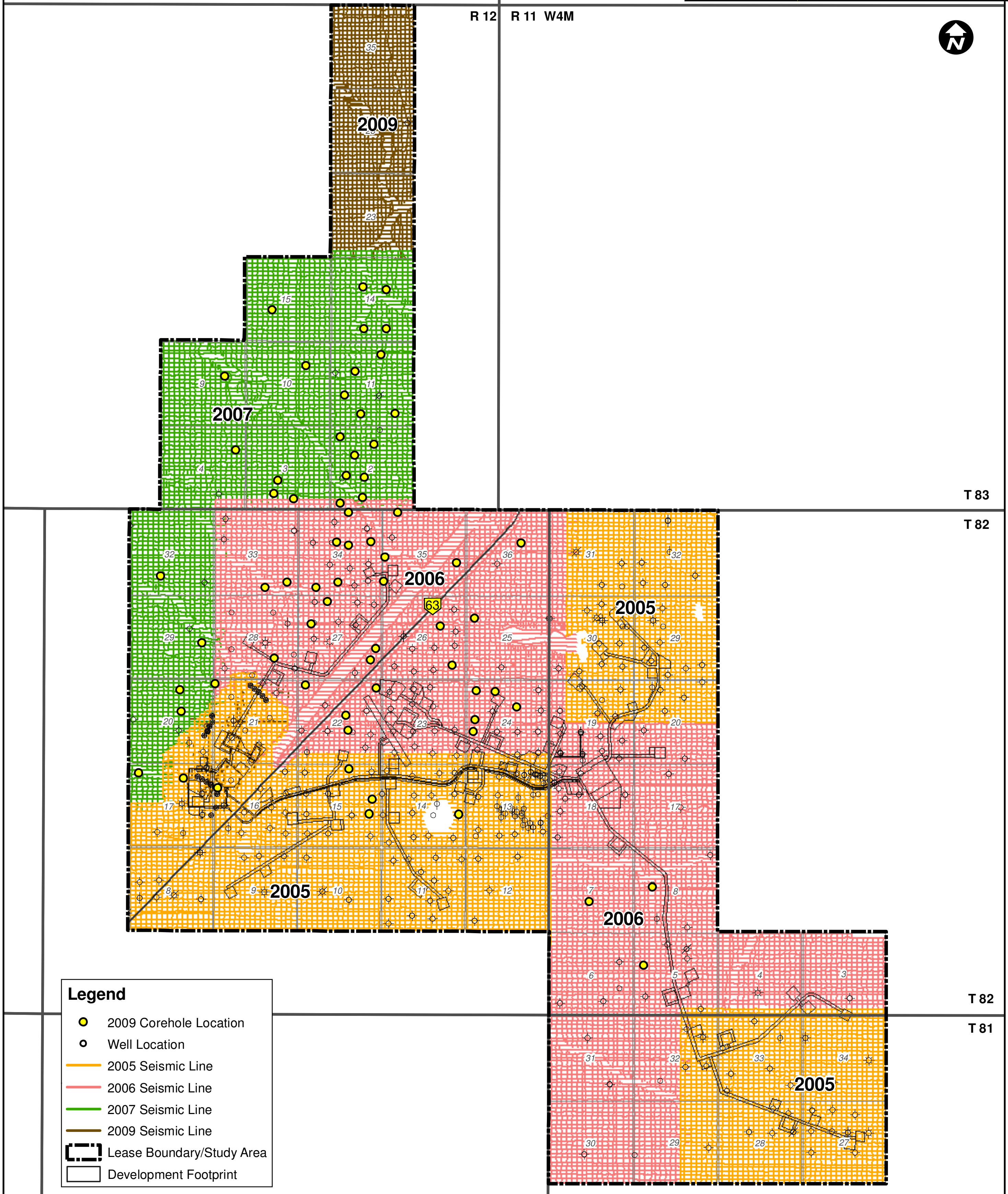
Connacher OIL AND GAS LIMITED

TITLE:

Phase 3 Development

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 19/10
PROJECT:	07-104

FIGURE: **B.1.1-3**



0 1 2 4

Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

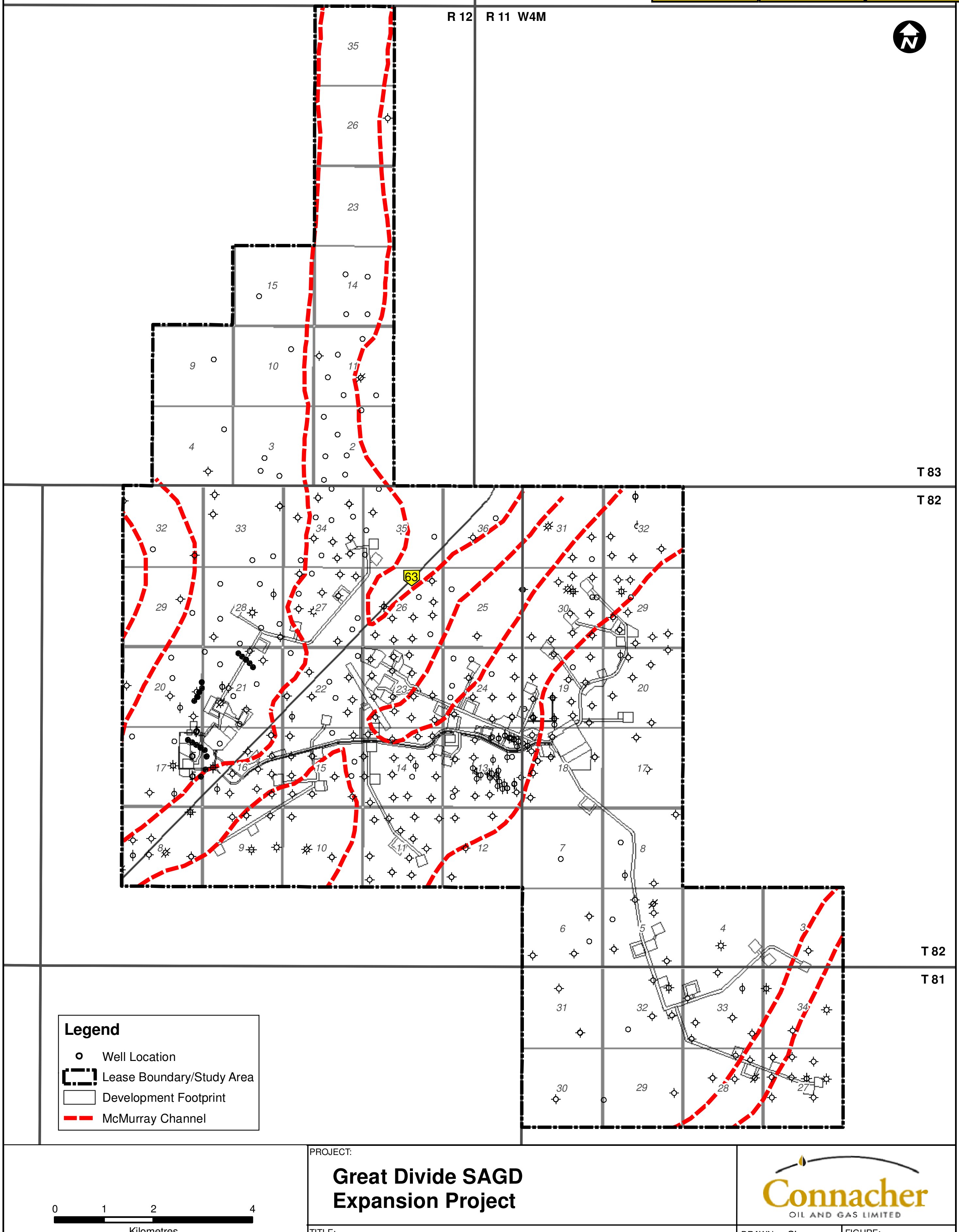
Connacher OIL AND GAS LIMITED

TITLE:

Exploration Activity Map - Corehole and 3D Seismic

DRAWN:	SL
CHECKED:	DM
DATE:	May 4/10
PROJECT:	07-104

FIGURE: **B.2.1-1**



REF: D. Loucks Consulting Drifter Projects Ltd. EIA
Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

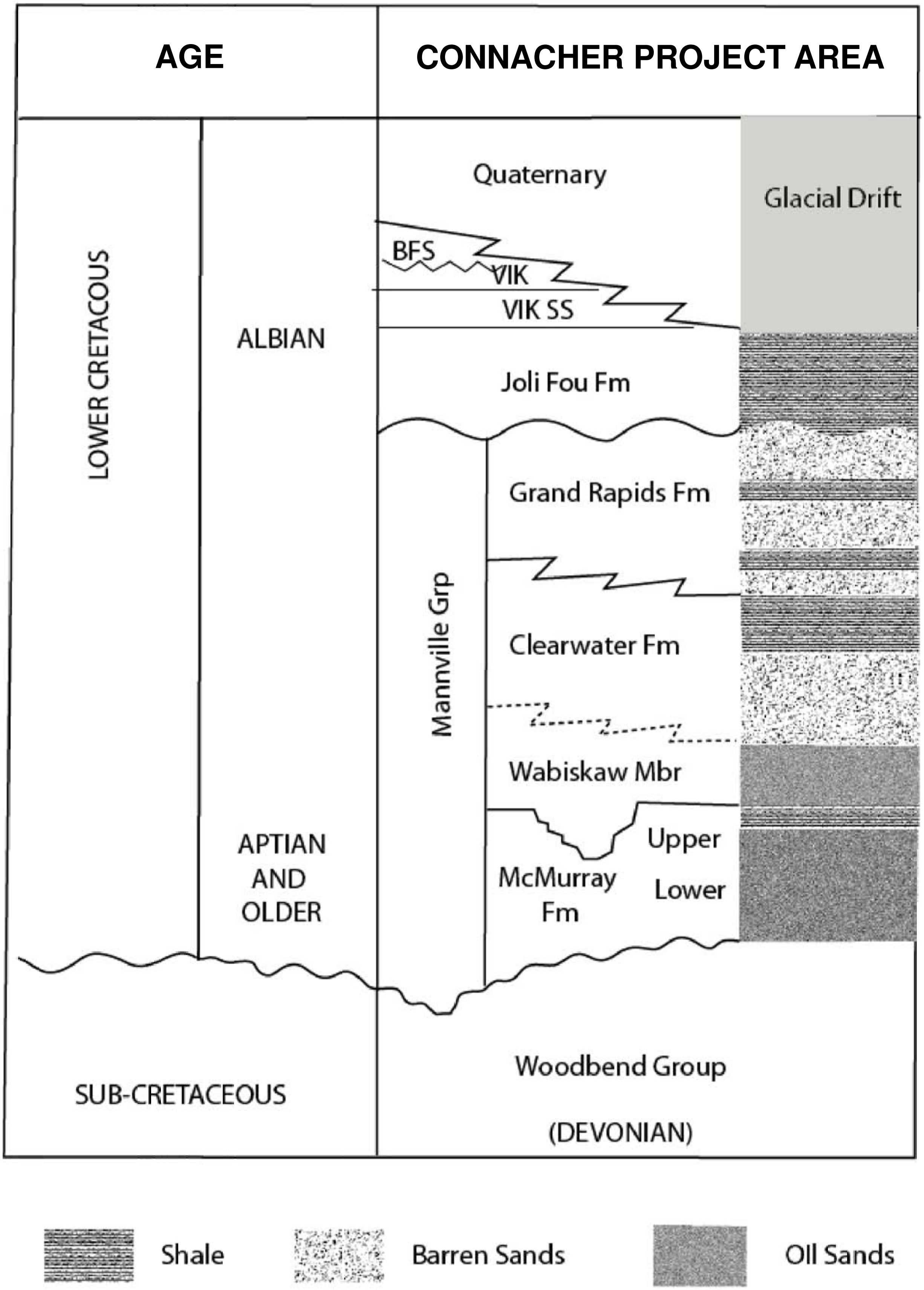
TITLE:

Stacked McMurray B2 and C Channel Trends

Connacher OIL AND GAS LIMITED

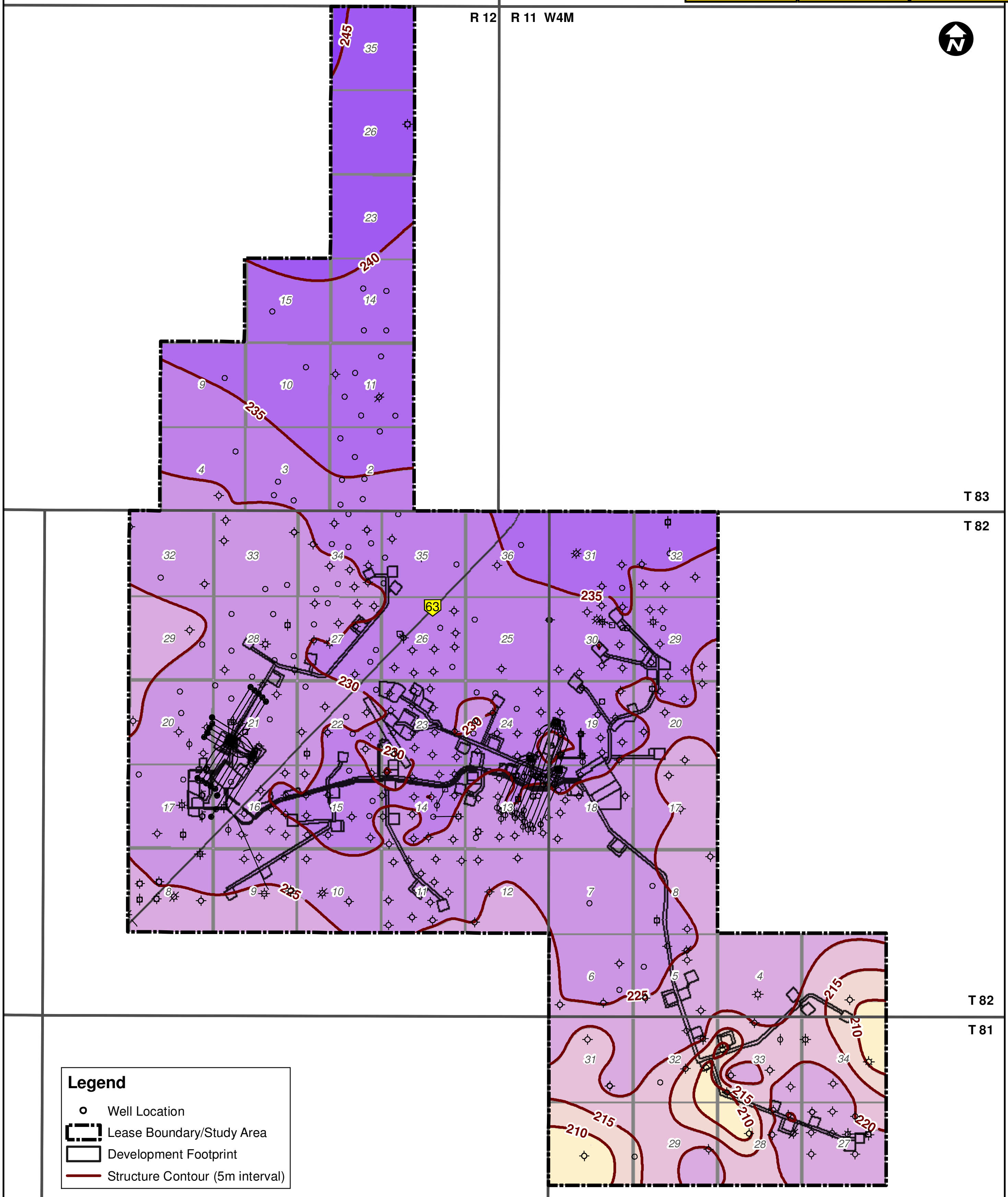
DRAWN:	SL
CHECKED:	DM
DATE:	Apr 19/10
PROJECT:	07-104

FIGURE: **B.2.1-2**



PROJECT: **Great Divide SAGD Expansion Project**	Connacher OIL AND GAS LIMITED
TITLE: **Stratigraphic Column**	DRAWN: SL CHECKED: DM DATE: Apr 19/10 PROJECT: 07-104
	FIGURE: **B.2.2-1**

REF: Connacher, 2010.



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

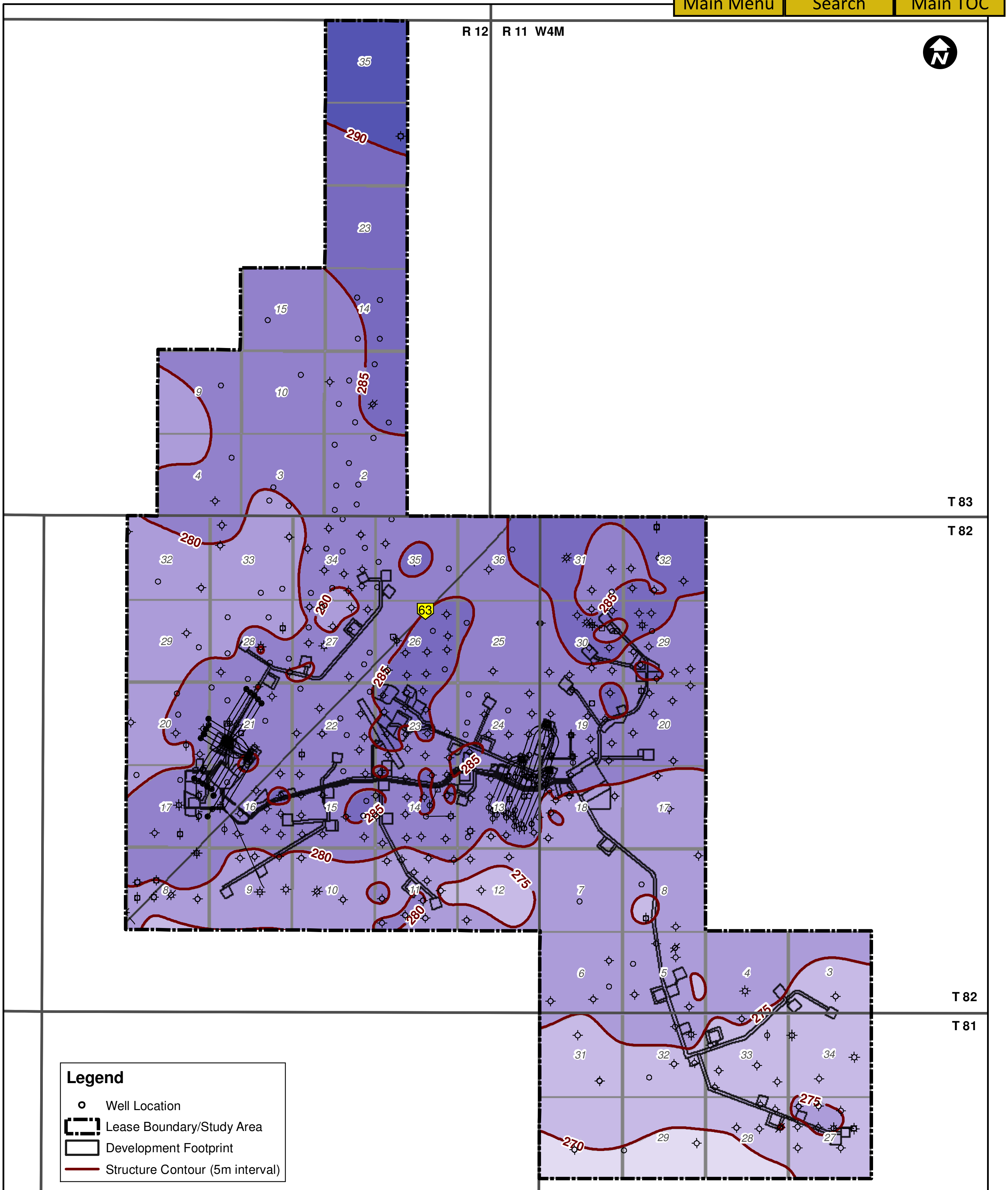
TITLE:

Woodbend Group Structure Map

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 21/10
PROJECT:	07-104

FIGURE:

B.2.2-2



REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

TITLE:

McMurray Structure Map

DRAWN: SL
CHECKED: DM
DATE: Apr 21/10
PROJECT: 07-104

FIGURE: **B.2.2-3**

Main Menu | Search | Main TOC

0 1 2 4

Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

TITLE:

McMurray Isopach Map

DRAWN: SL

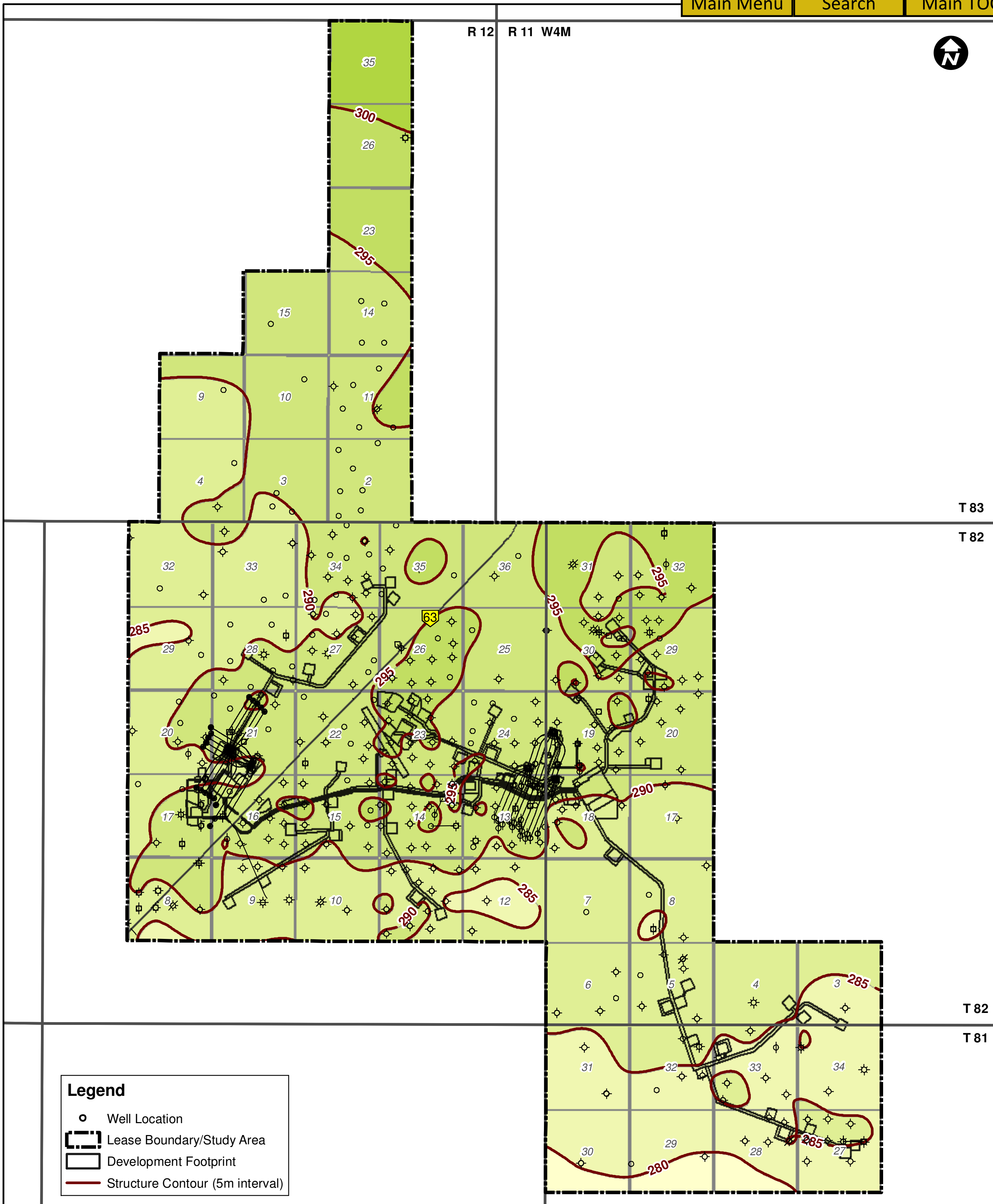
CHECKED: DM

DATE: Apr 21/10

PROJECT: 07-104

FIGURE:

B.2.2-4



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

Connacher
OIL AND GAS LIMITED

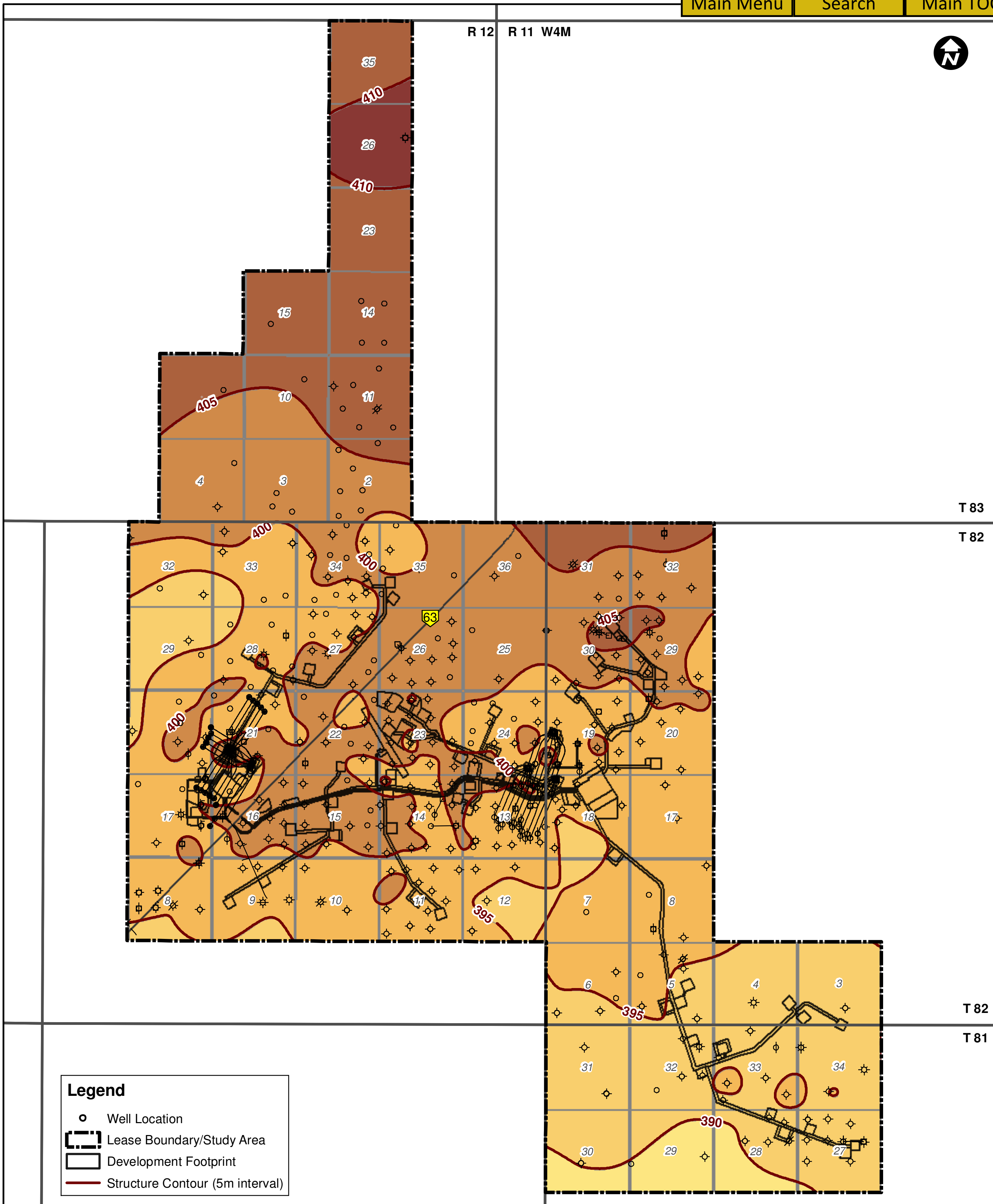
TITLE:

Wabiskaw Structure Map

DRAWN:	SL
CHECKED:	DM
DATE:	Apr21/10
PROJECT:	07-104

FIGURE:

B.2.2-5



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA
Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

TITLE:

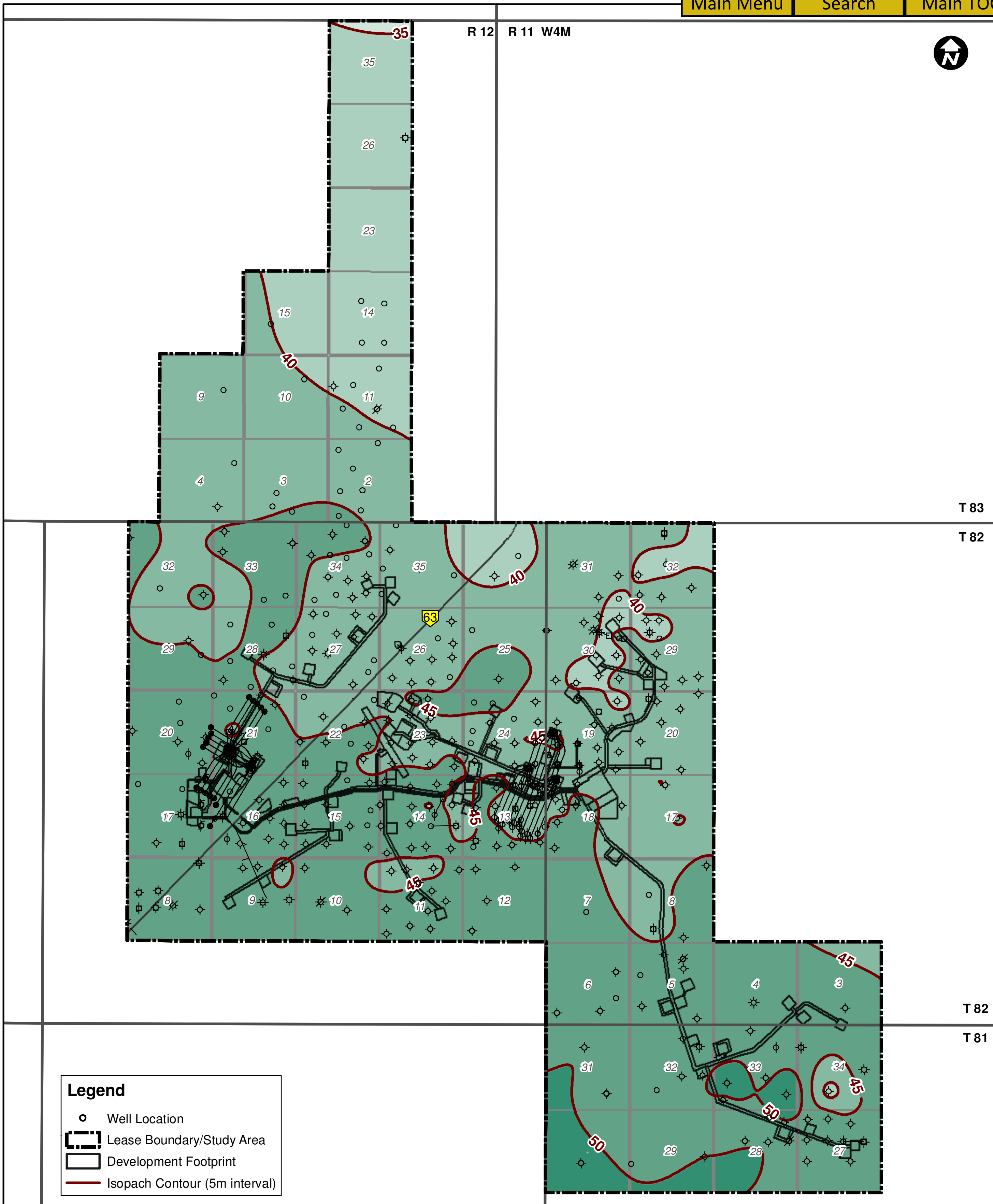
Lower Grand Rapids Structure Map

Connacher OIL AND GAS LIMITED

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 21/10
PROJECT:	07-104

FIGURE:

B.2.2-6



PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

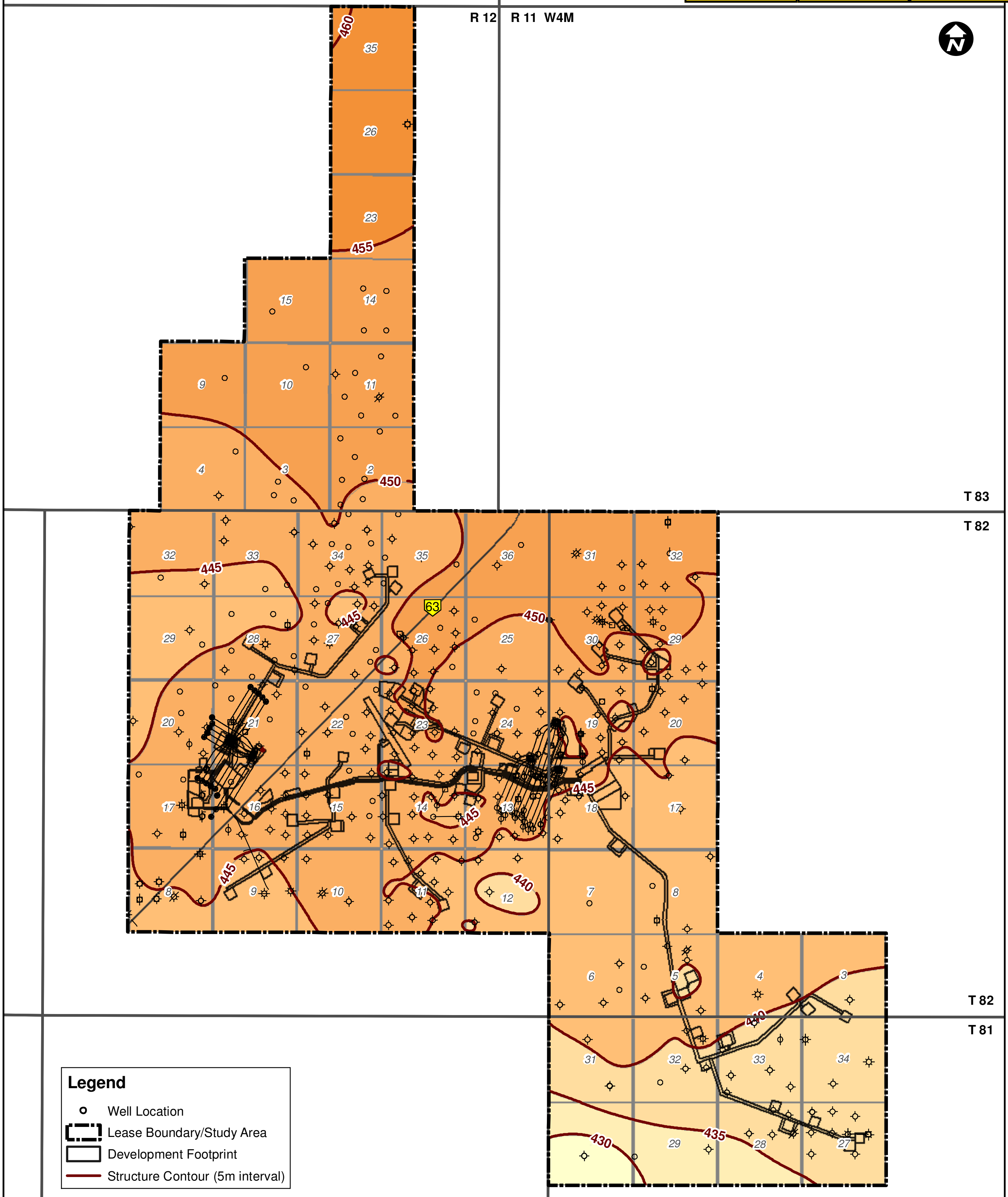
TITLE:

Lower Grand Rapids Sands Isopach Map

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 19/10
PROJECT:	07-104

FIGURE: **B.2.2-7**

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.



REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

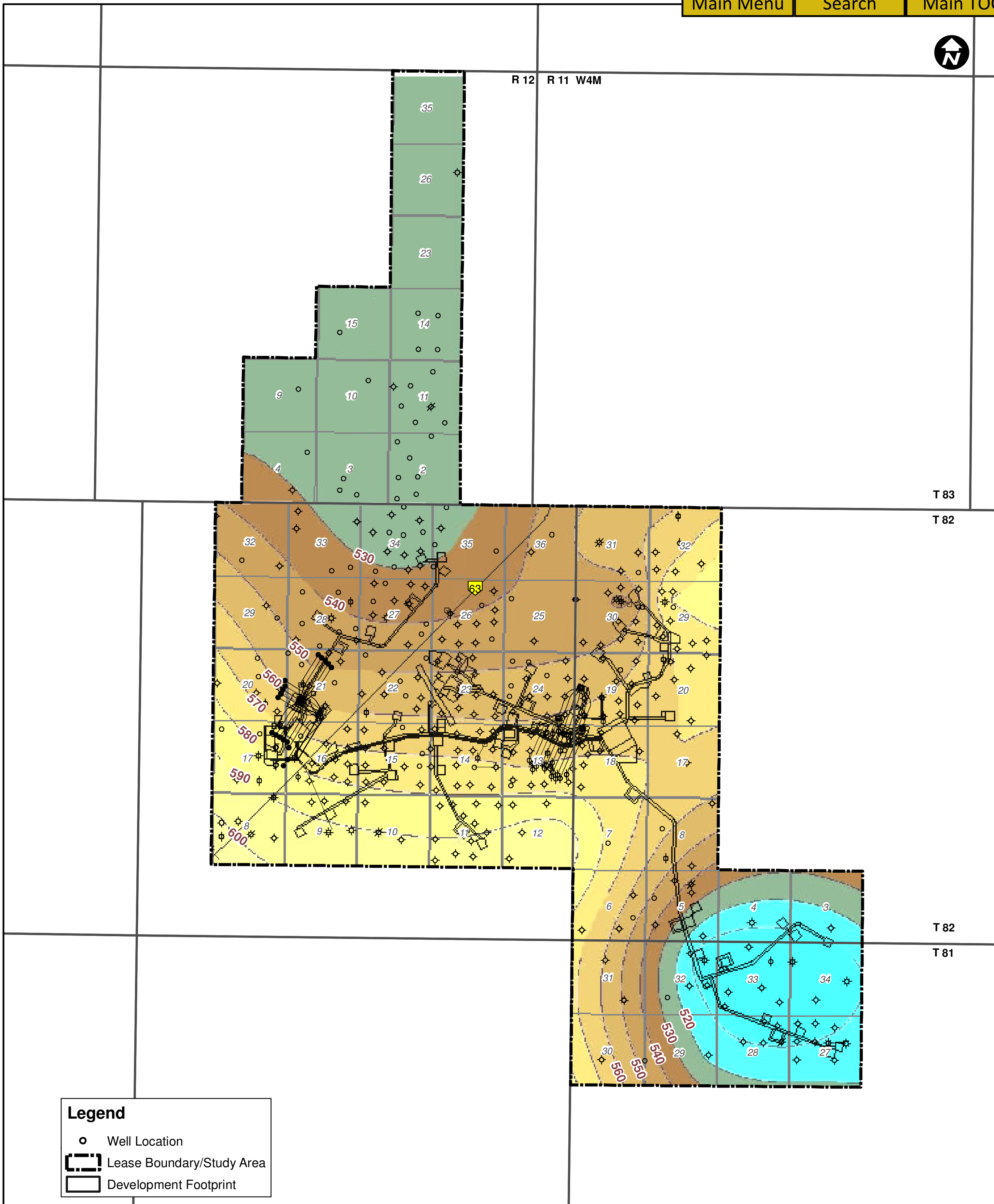
Connacher OIL AND GAS LIMITED

TITLE:

Upper Grand Rapids Structure Map

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104

FIGURE: **B.2.2-8**



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010. Westwater Environmental Ltd., 2007.

PROJECT:

Great Divide SAGD Expansion Project

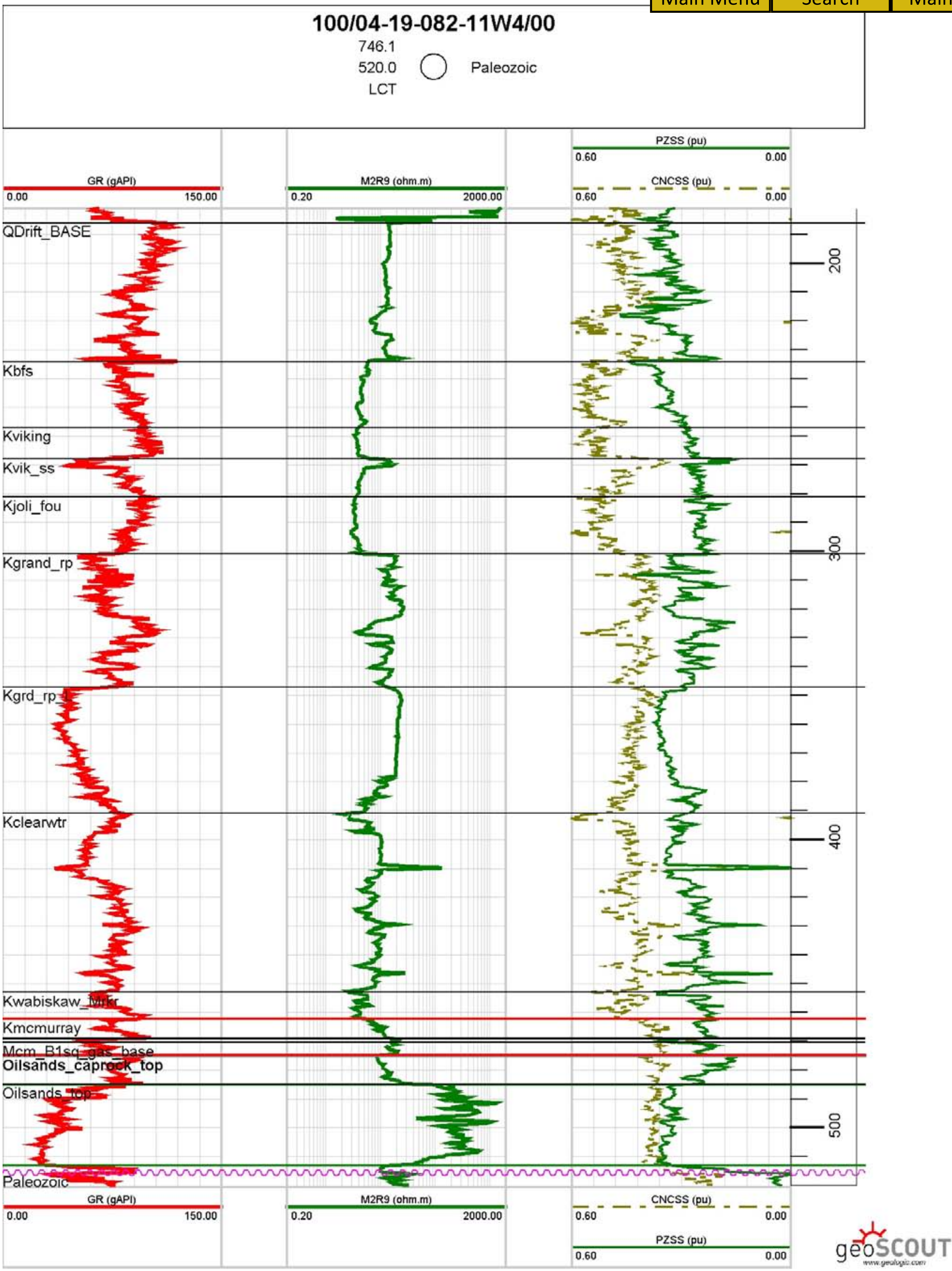
Connacher OIL AND GAS LIMITED

TITLE:

Quaternary Structure Map

DRAWN:	PS
CHECKED:	DM
DATE:	Apr 23/10
PROJECT:	07-104

FIGURE: **B.2.2-9**



PROJECT:

Great Divide SAGD Expansion Project

TITLE:

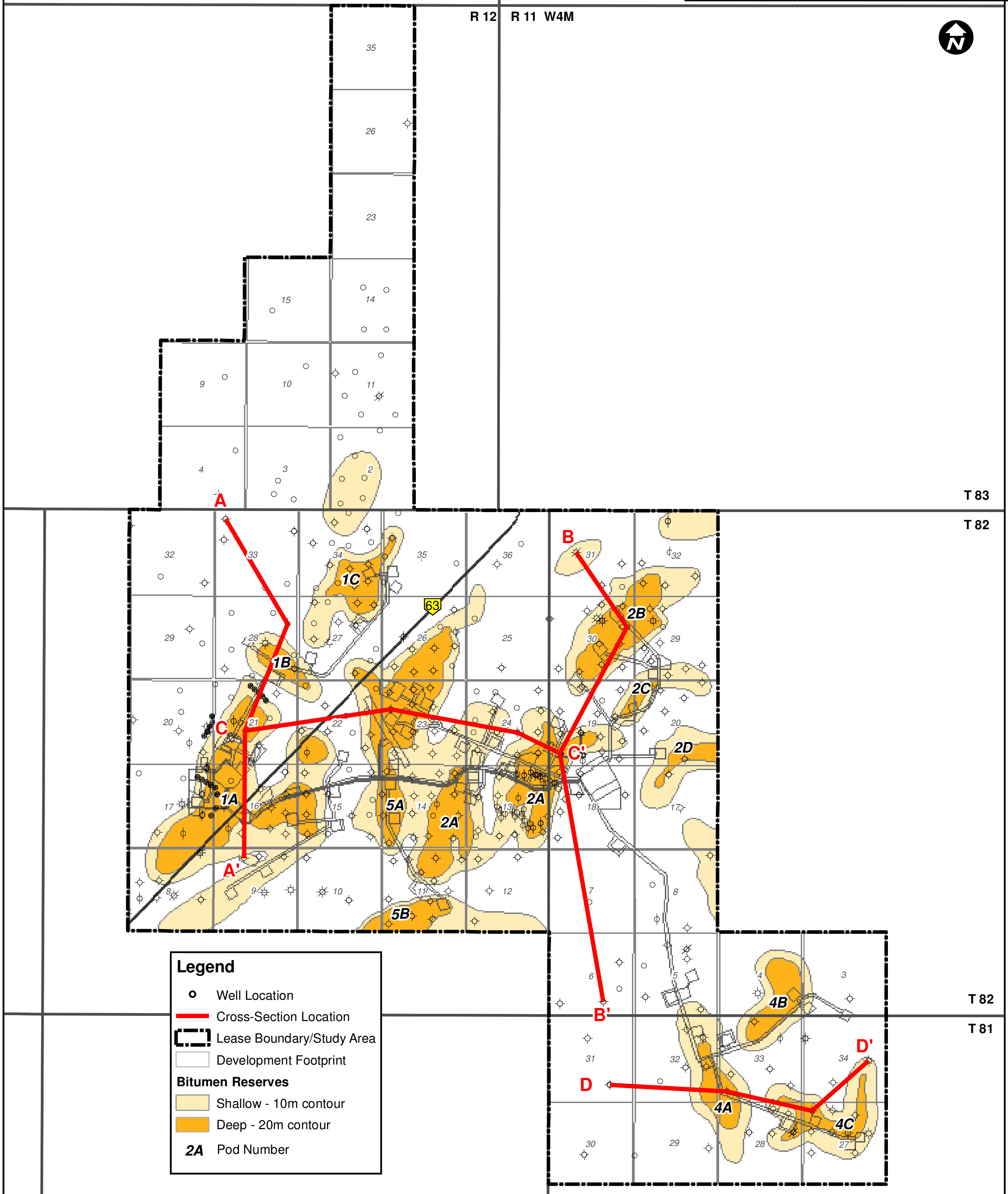
4-19 Type Log

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104

FIGURE: **B.2.3-1**

Connacher OIL AND GAS LIMITED

REF: Connacher, 2007



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

Connacher
OIL AND GAS LIMITED

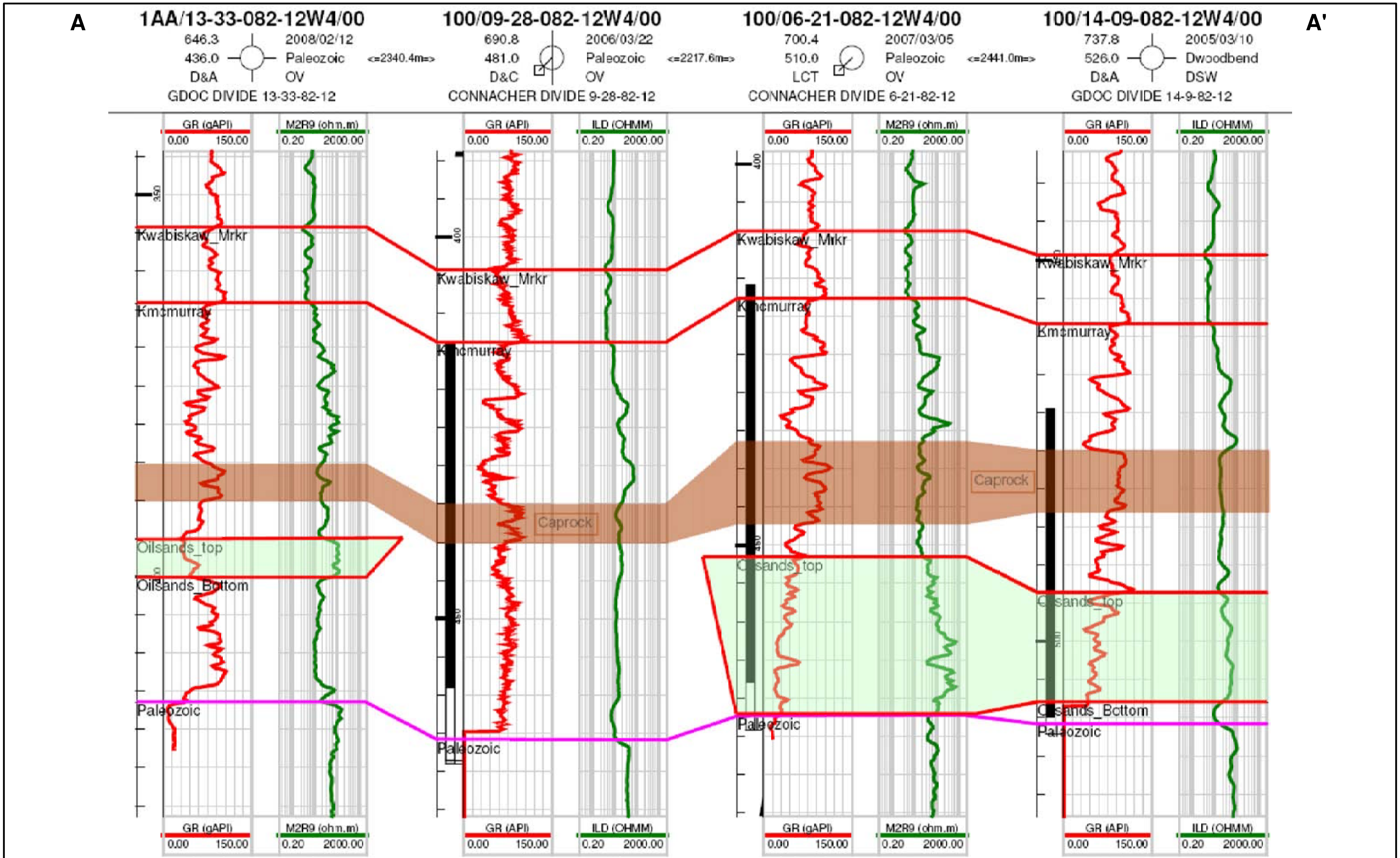
TITLE:

Oilsands Pods and Cross-Sections

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 19/10
PROJECT:	07-104

FIGURE:

B.2.3-2



REF: Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

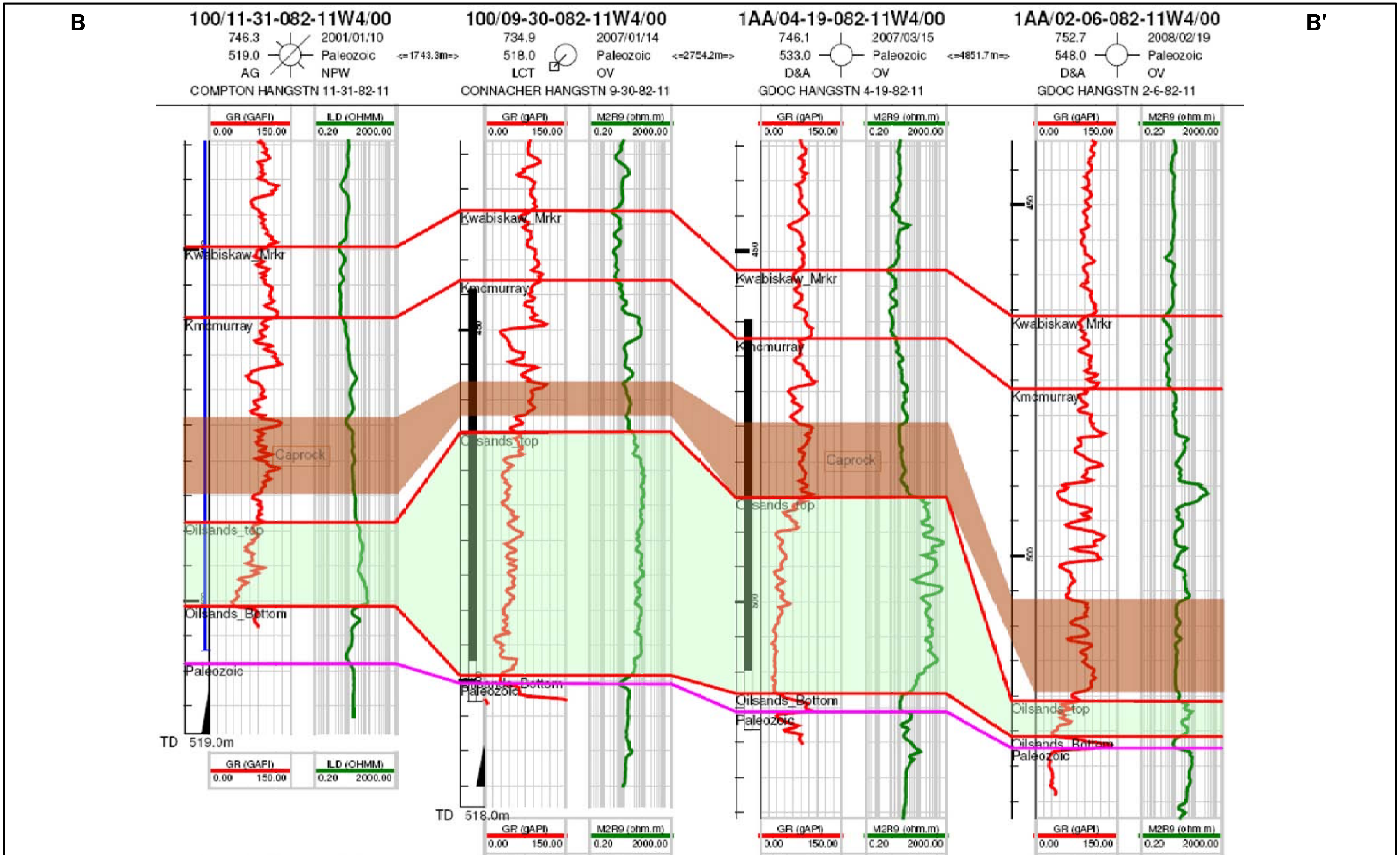
TITLE:

Section A-A' North-South I

Connacher OIL AND GAS LIMITED

DRAWN: SL
CHECKED: DM
DATE: Apr 20/10
PROJECT: 07-104

FIGURE: **B.2.3-3**



PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

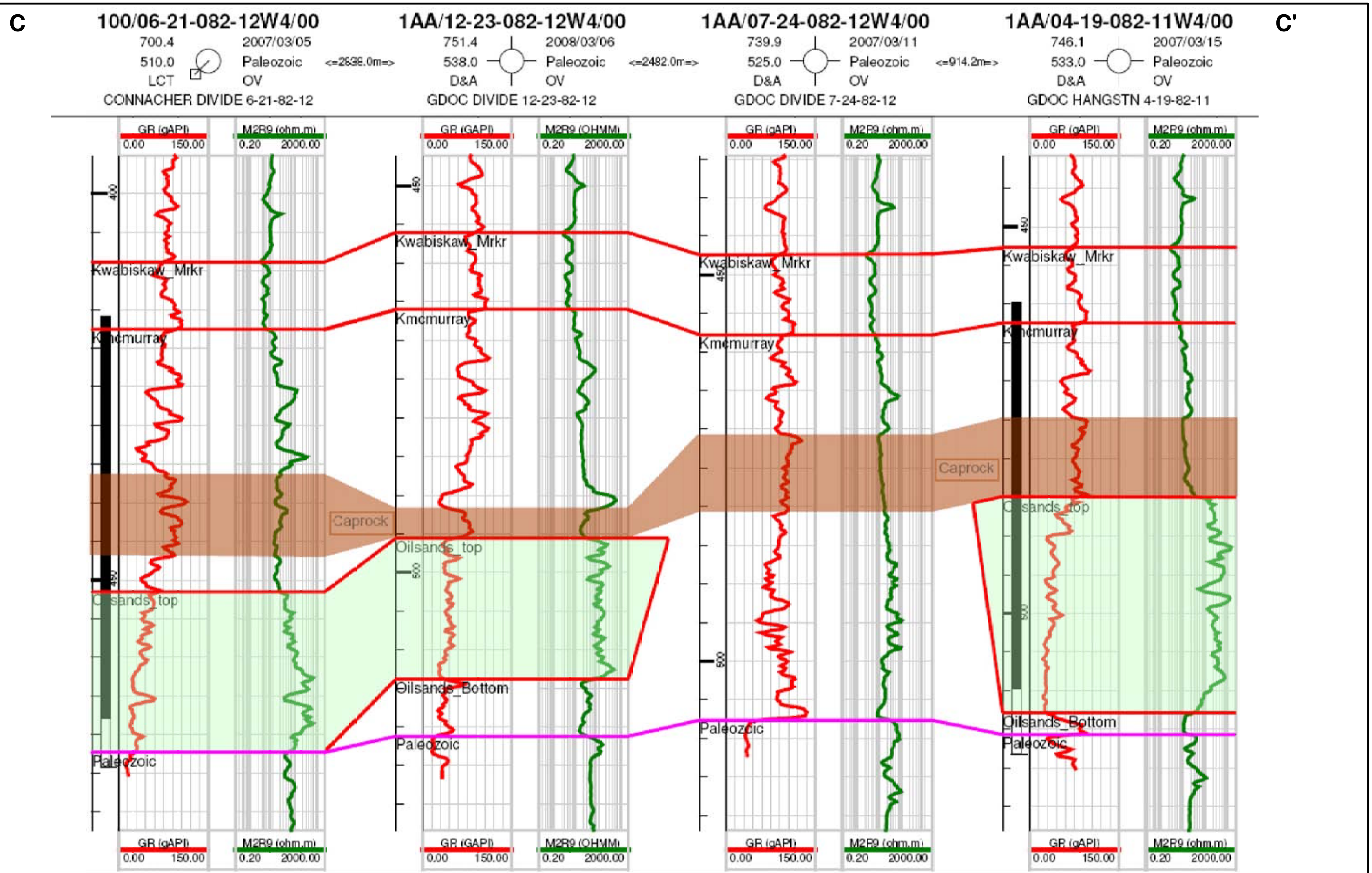
TITLE:

Section B-B' North-South II

DRAWN: SL
CHECKED: DM
DATE: Apr 20/10
PROJECT: 07-104

FIGURE: **B.2.3-4**

REF: Connacher, 2010.



REF: Connacher, 2010.

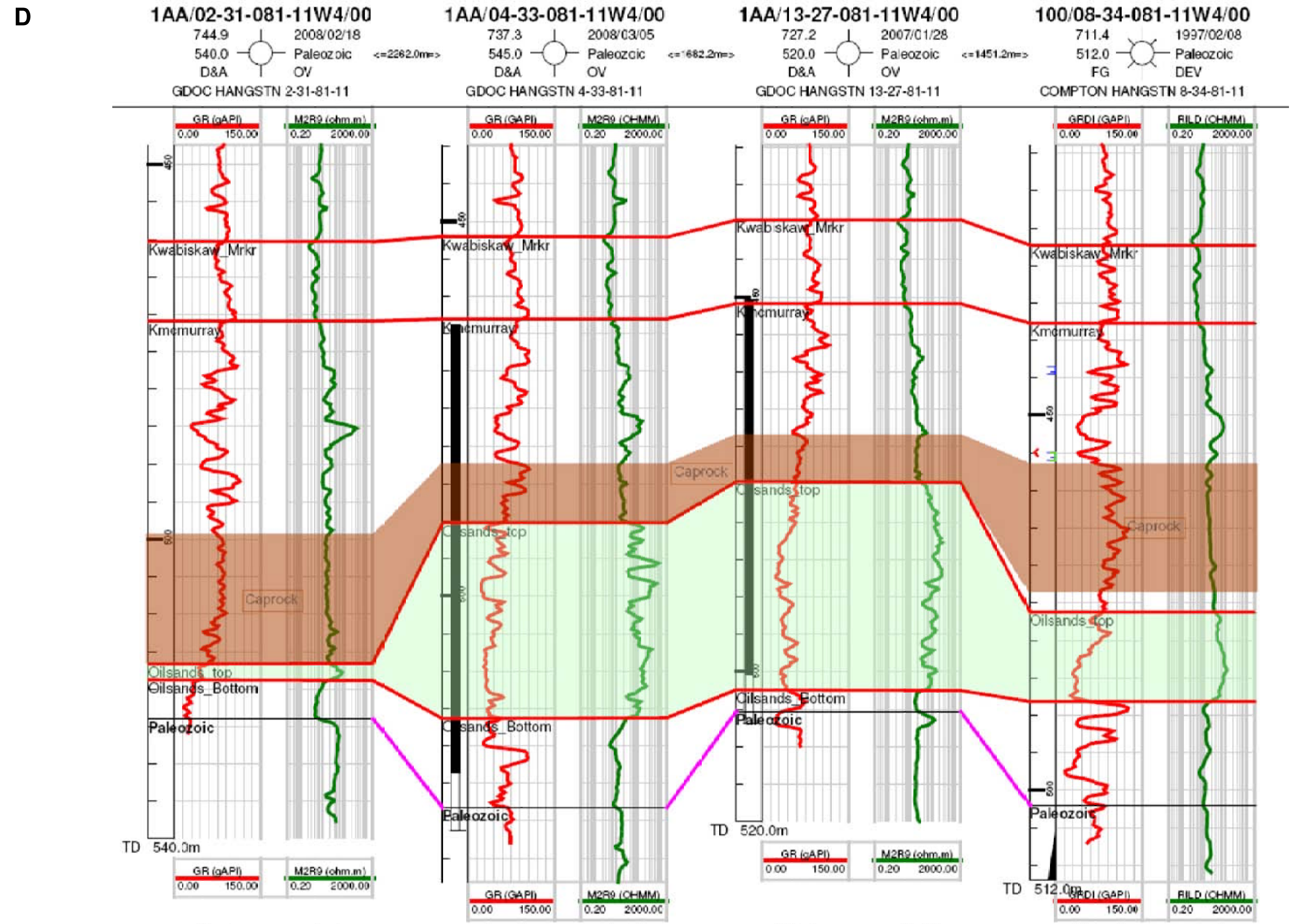
PROJECT:
Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

TITLE:
Section C-C' East-West I

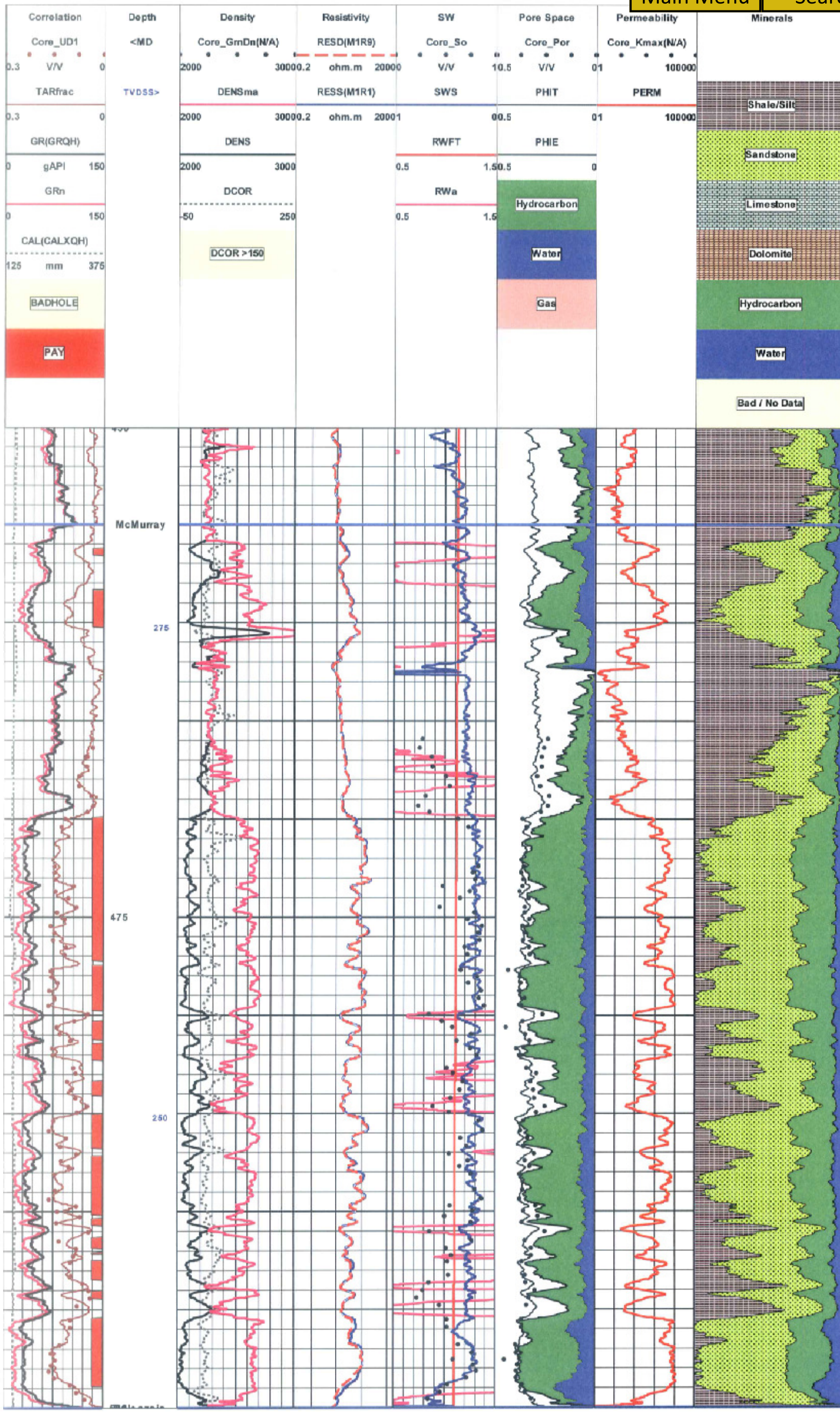
DRAWN: SL
CHECKED: DM
DATE: Apr 20/10
PROJECT: 07-104

FIGURE: **B.2.3-5**



PROJECT:	
Great Divide SAGD Expansion Project	Connacher OIL AND GAS LIMITED
TITLE: **Section D-D' East-West II**	DRAWN: SL CHECKED: DM DATE: Apr 20/10 PROJECT: 07-104
FIGURE:	**B.2.3-6**

REF: Connacher, 2010.



REF: Connacher, 2007

PROJECT:

Great Divide SAGD Expansion Project

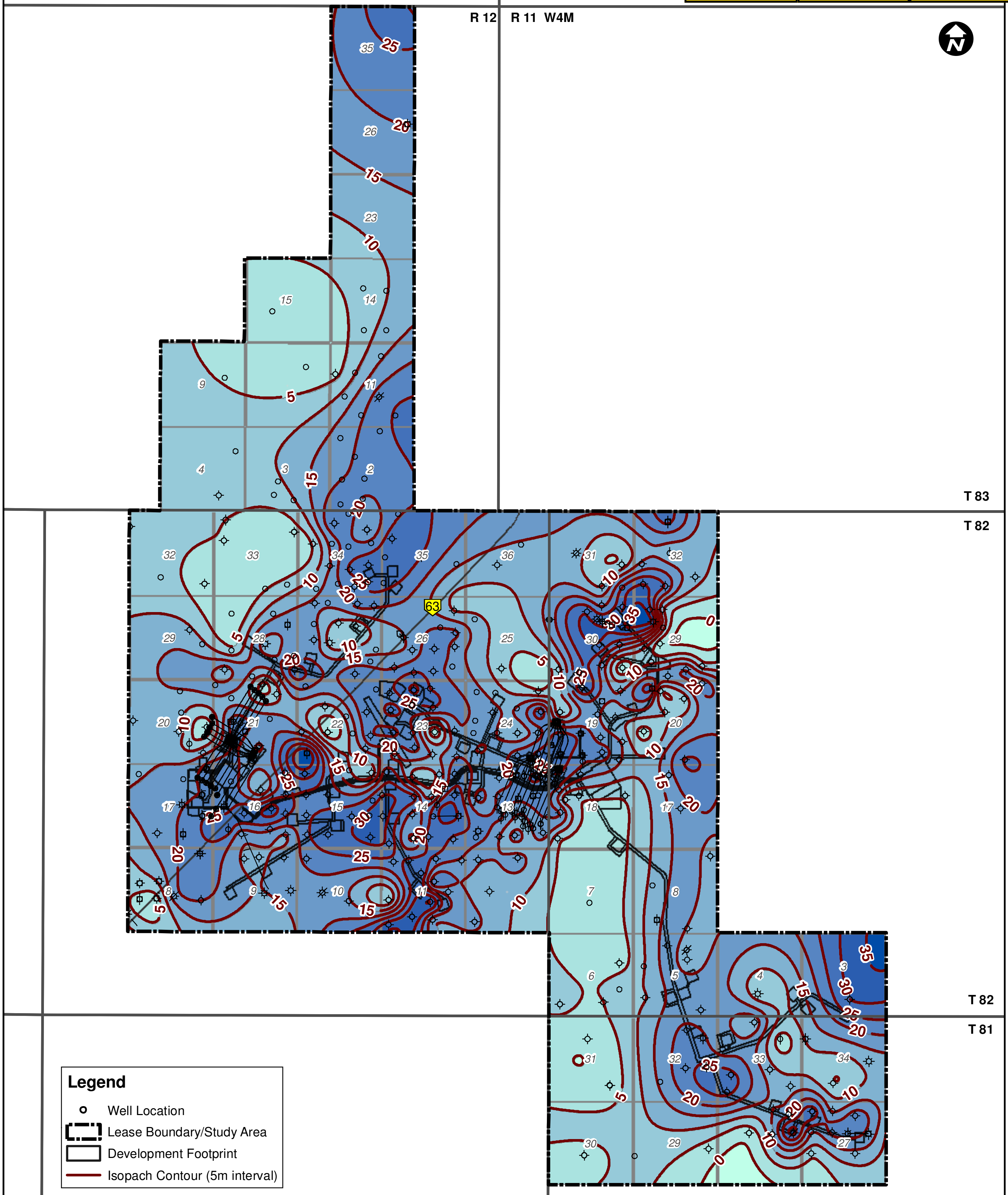
TITLE:

8-30 Log Interpretation

Connacher OIL AND GAS LIMITED

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104

FIGURE: **B.2.3-7**



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

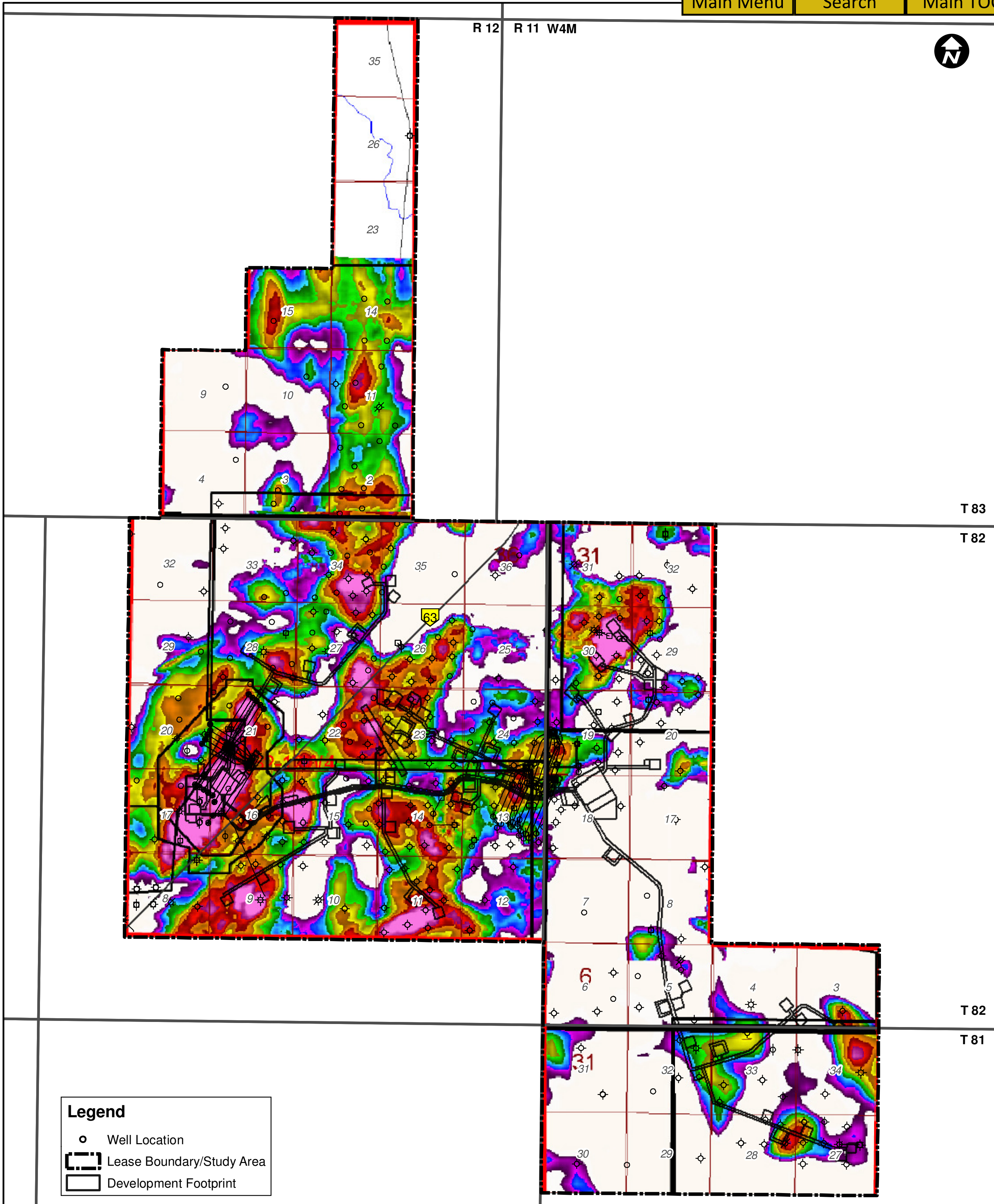
Connacher
OIL AND GAS LIMITED

TITLE:

Isopach of the Oil Sands

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104
FIGURE:	**B.2.3-8**

Main Menu | Search | Main TOC



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

TITLE:

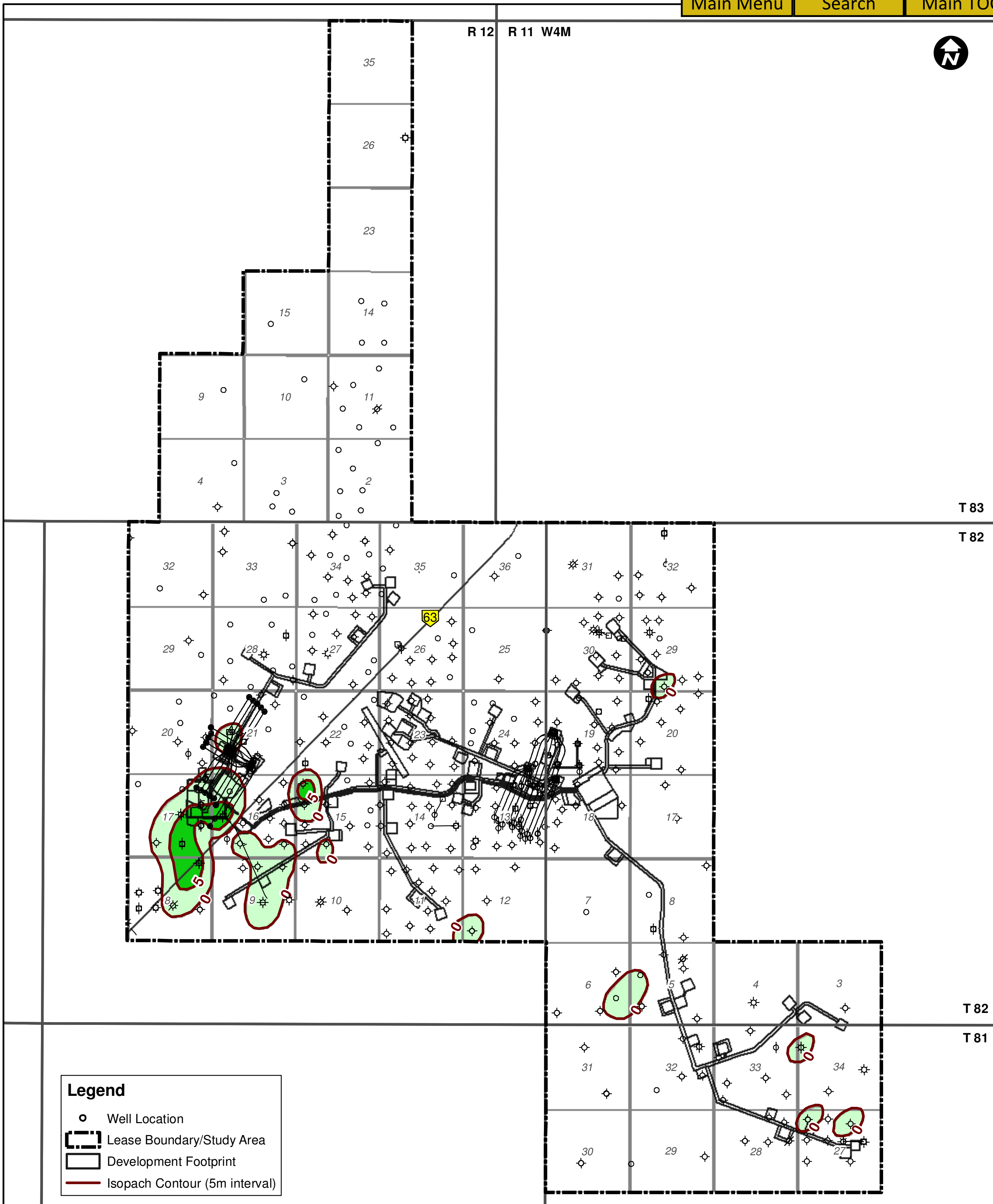
3D Seismic Isochron Interpretation of the Oil Sands

Connacher OIL AND GAS LIMITED

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104

FIGURE: **B.2.3-9**

Main Menu | Search | Main TOC



REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

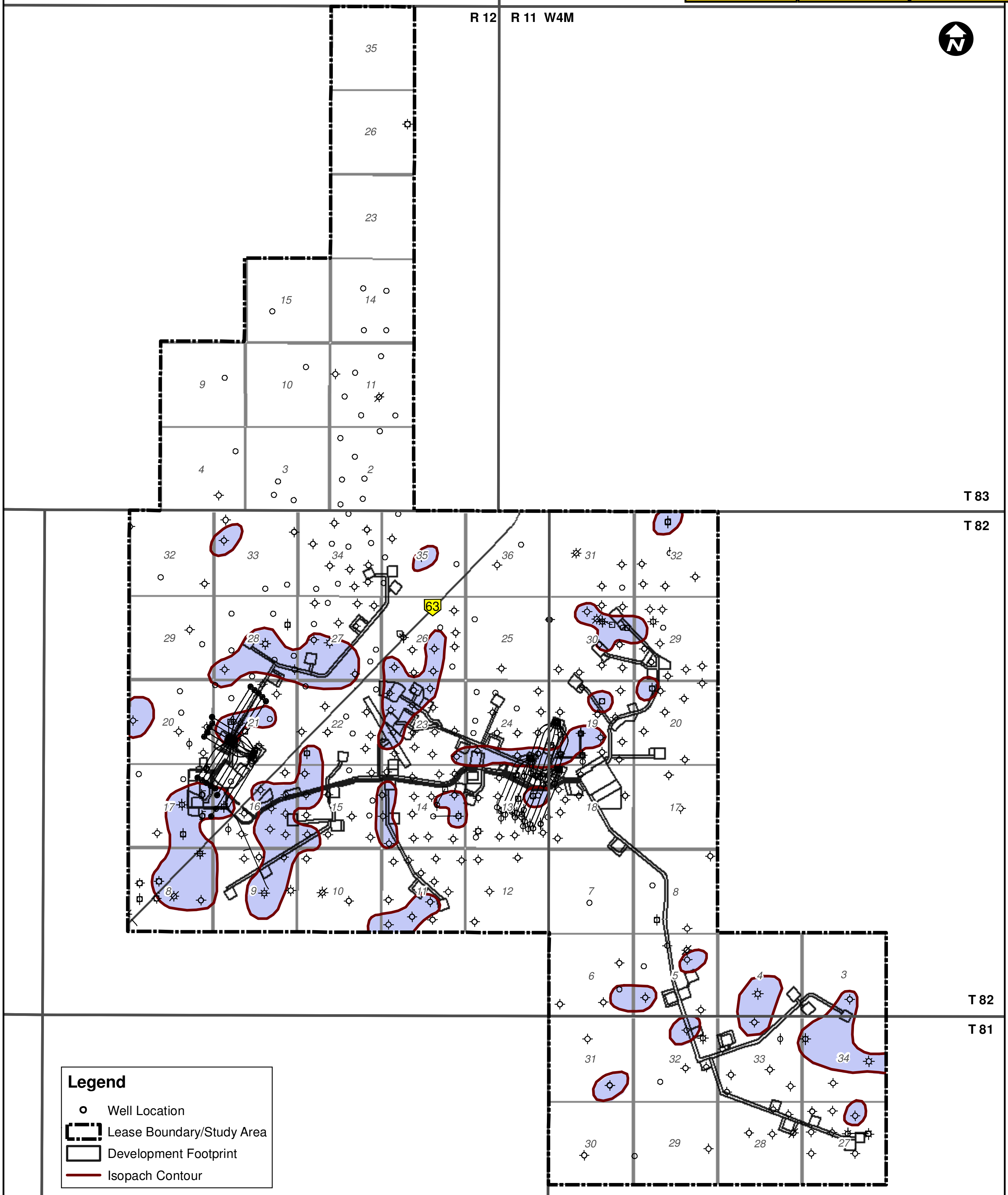
Connacher Oil and Gas Limited

TITLE:

Isopach of Associated McMurray Gas

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 21/10
PROJECT:	07-104

FIGURE: **B.2.4-1**



0 1 2 4

Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

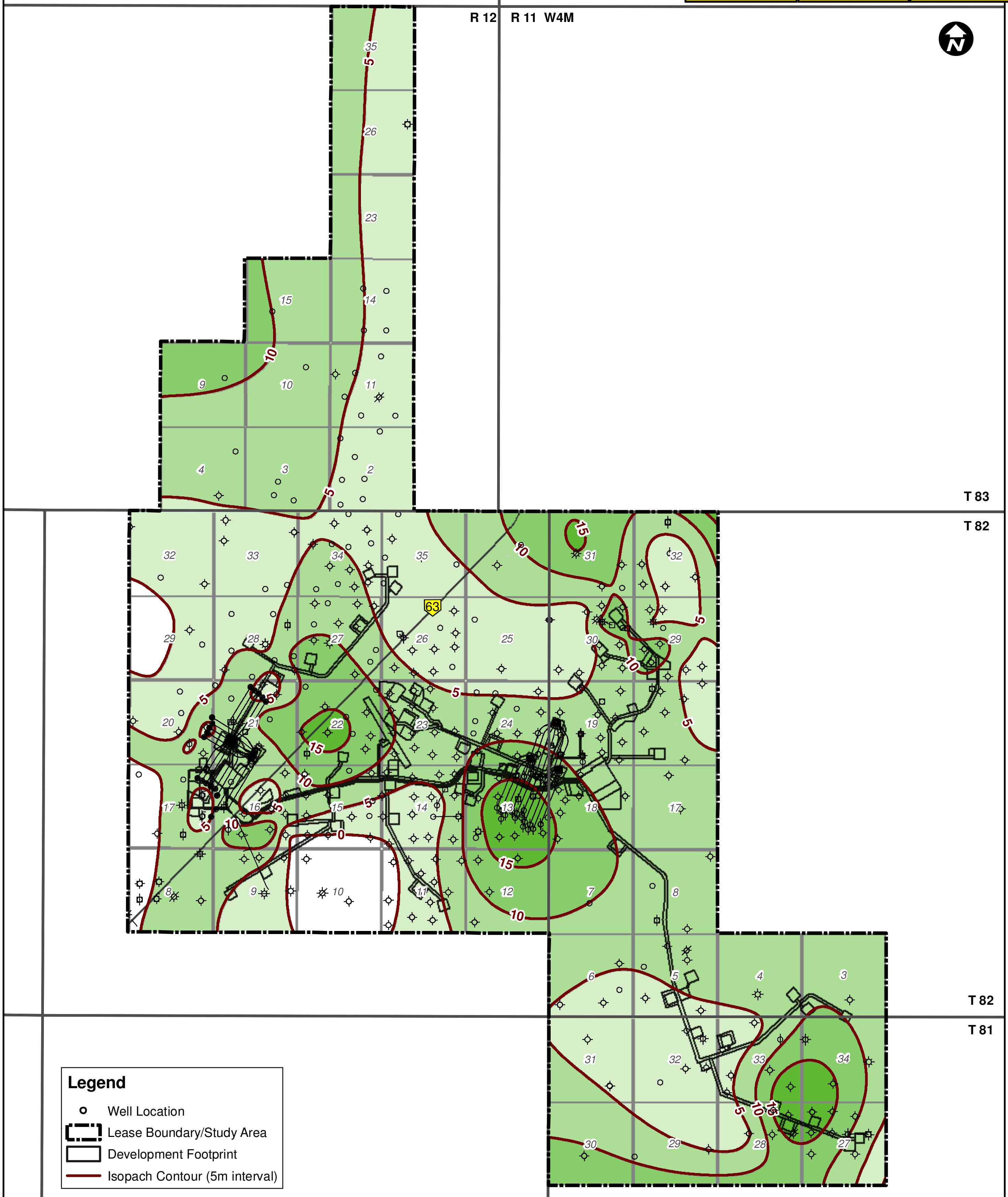
Connacher OIL AND GAS LIMITED

TITLE:

Isopach of Non-Associated Gas

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104

FIGURE: **B.2.4-2**



0 1 2 4
Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

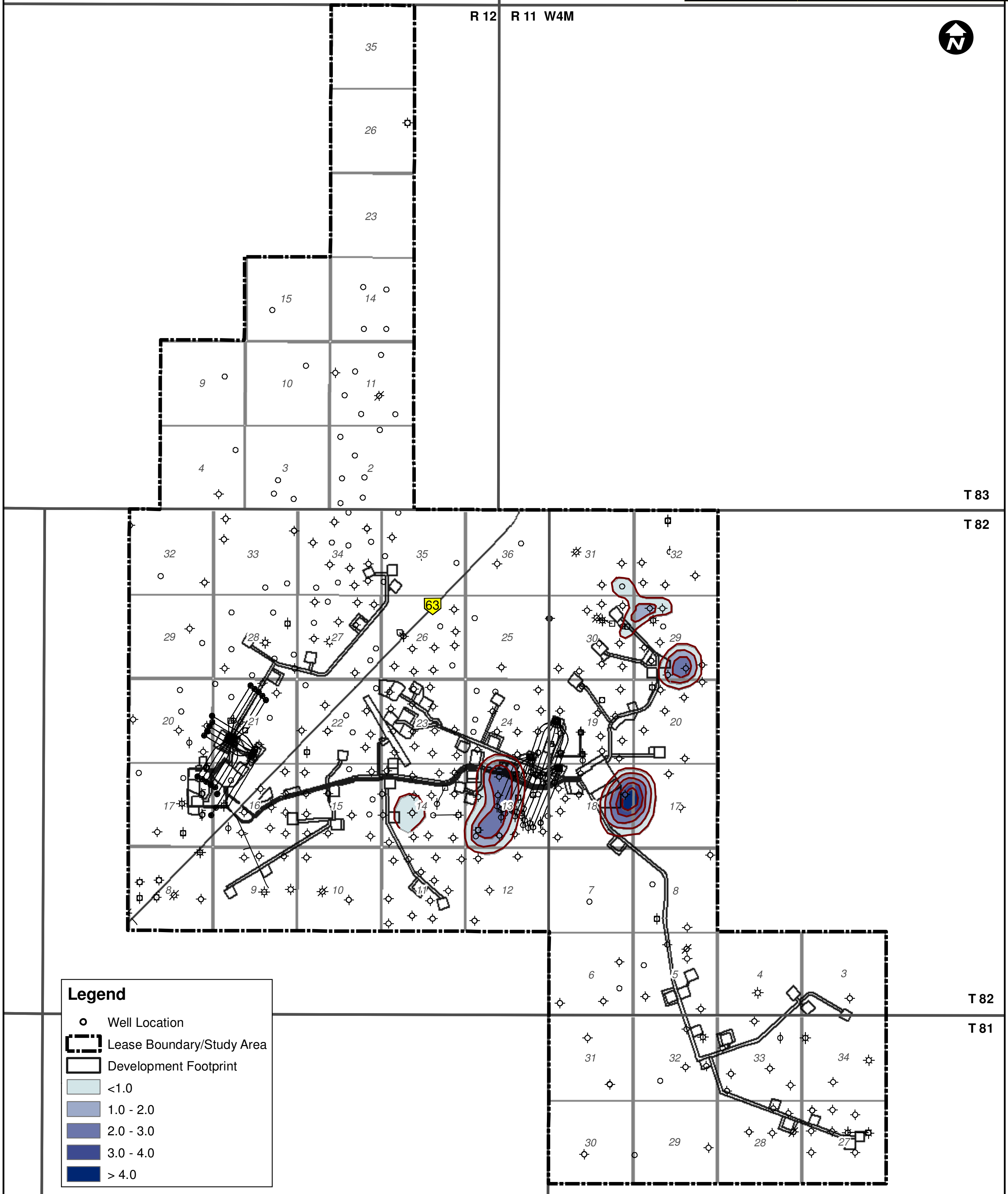
Connacher OIL AND GAS LIMITED

TITLE:

Overall Thickness and Distribution of the Caprock

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 21/10
PROJECT:	07-104
FIGURE:	B.2.4-3

Main Menu | Search | Main TOC



REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

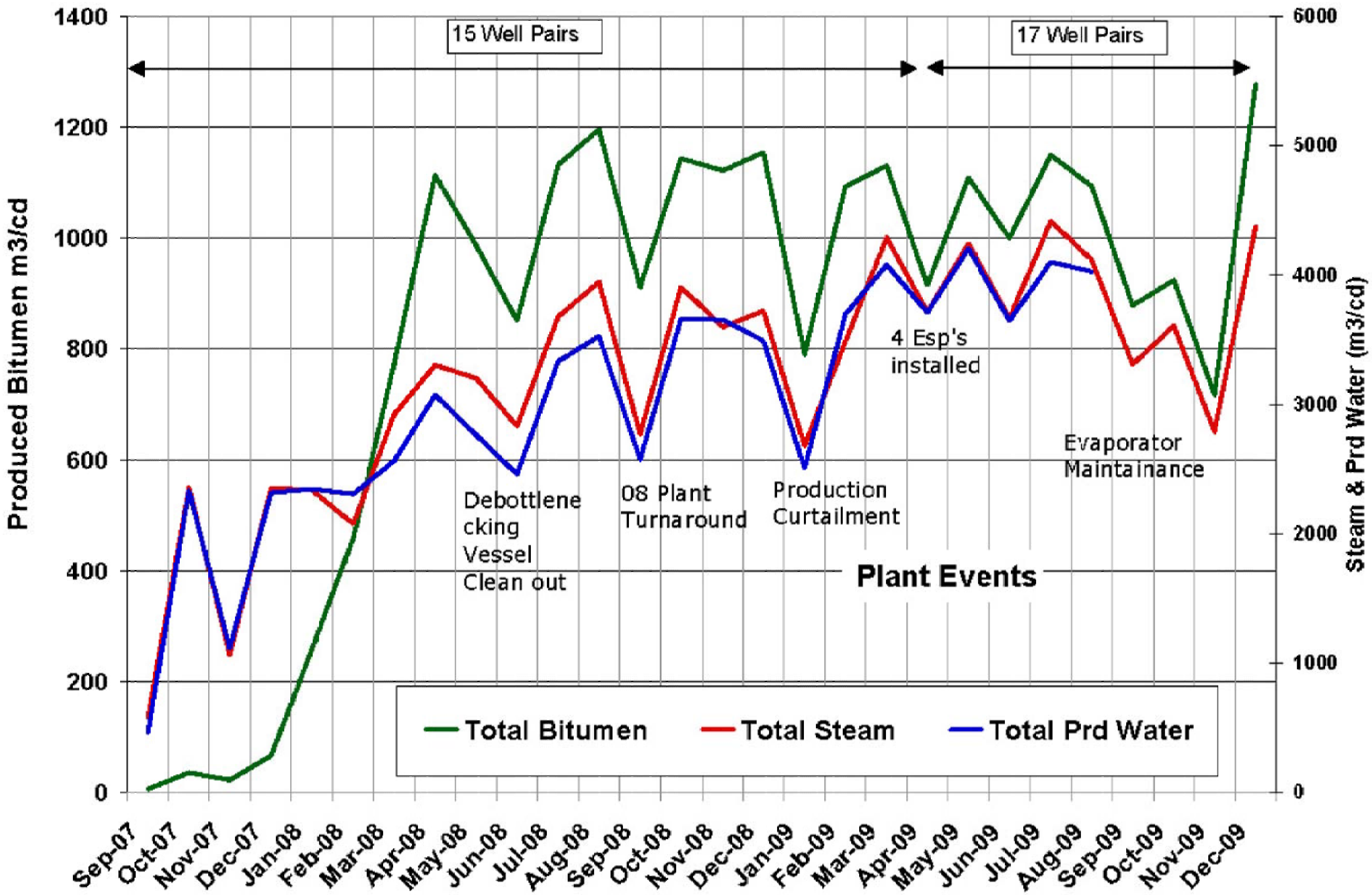
Connacher OIL AND GAS LIMITED

TITLE:

McMurray Base Water

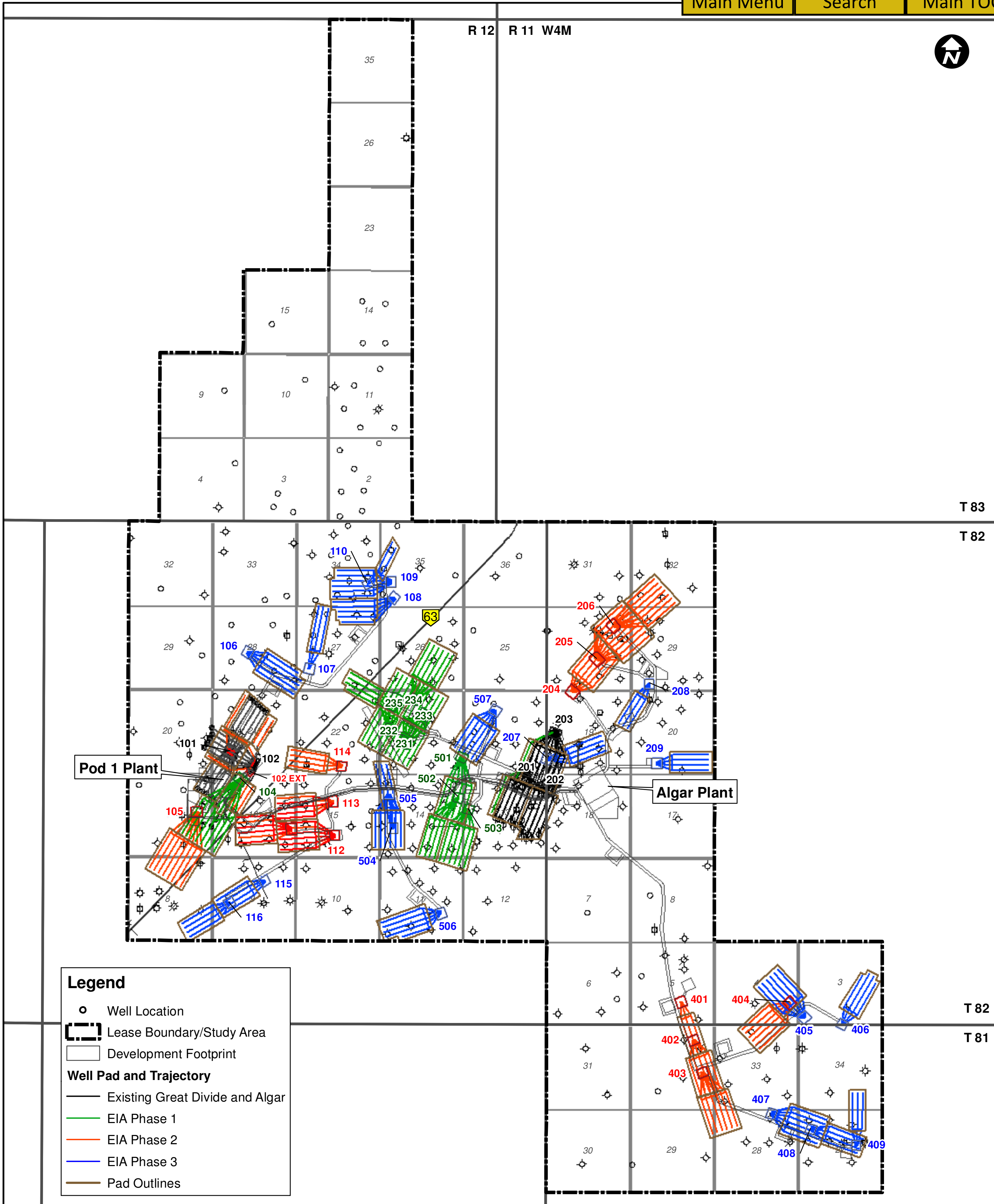
DRAWN:	SL
CHECKED:	DM
DATE:	Apr 21/10
PROJECT:	07-104

FIGURE: **B.2.4-4**



REF: Connacher, 2010.

PROJECT: Great Divide SAGD Expansion Project	Connacher Oil and Gas Limited	
TITLE: Pod 1- Initial Performance of 17 Well Pairs	DRAWN: SL CHECKED: DM DATE: Apr 20/10 PROJECT: 07-104	FIGURE: B.3.3-1



0 1 2 4

Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

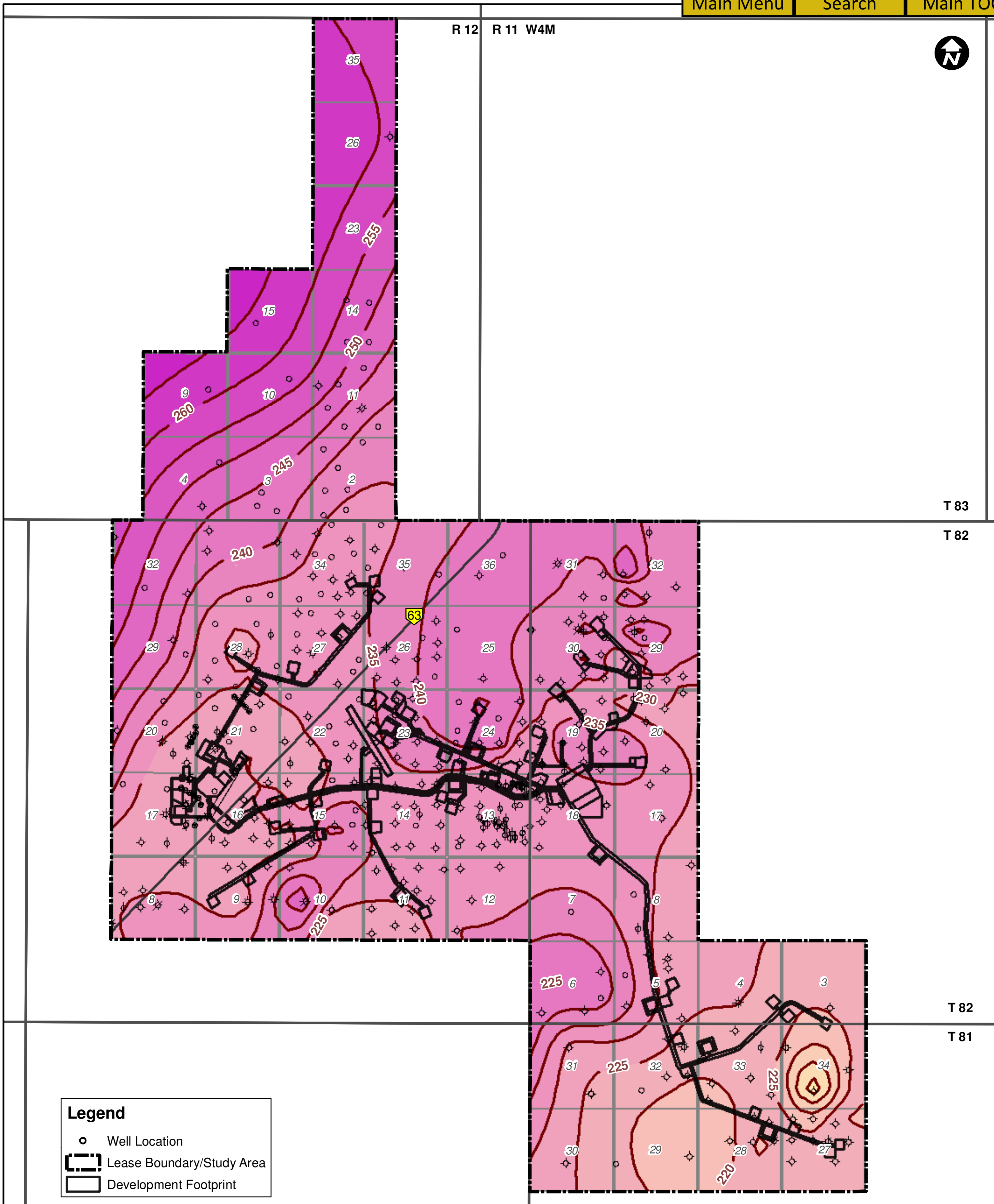
TITLE:

Life of Project Development Plan

Connacher OIL AND GAS LIMITED

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104

FIGURE: **B.3.3-2**



0 1 2 4

Kilometres

REF: D. Loucks Consulting Drifter Projects Ltd. EIA Master Plan Rev 5, 27Oct09; Connacher, 2010.

PROJECT:

Great Divide SAGD Expansion Project

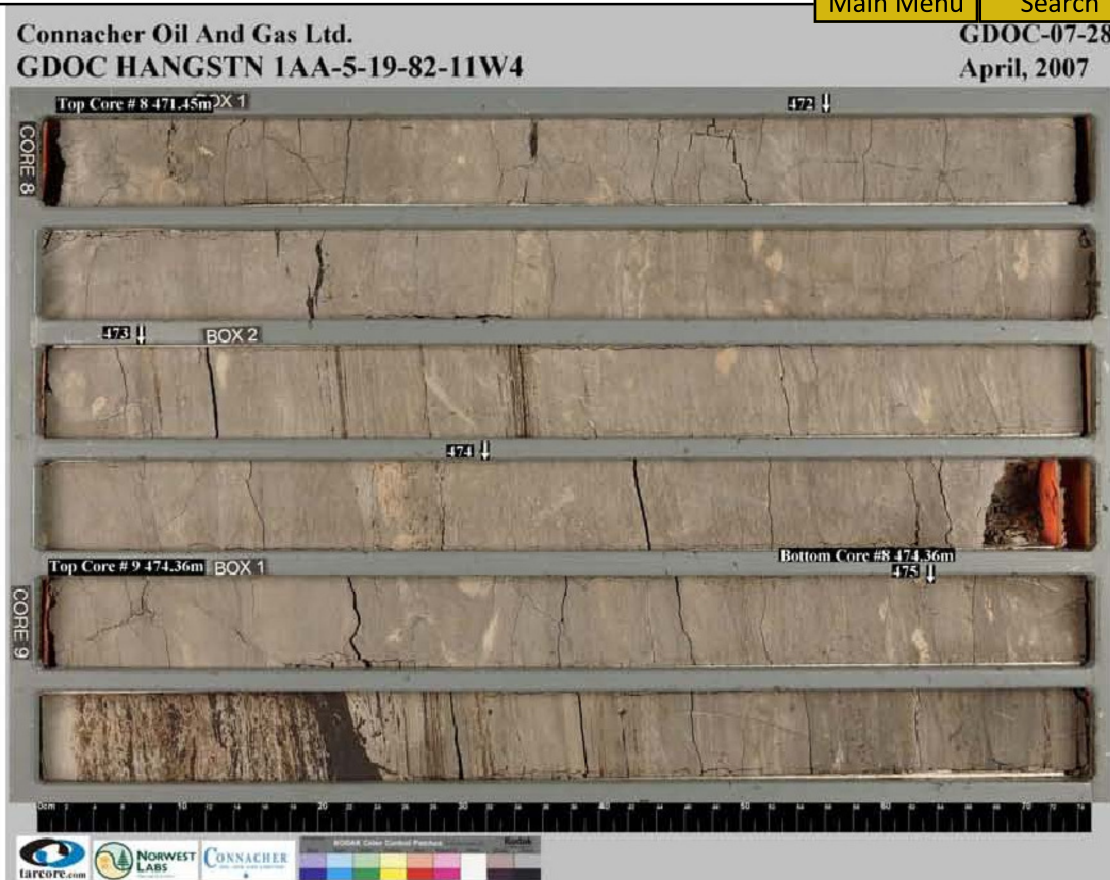
Connacher OIL AND GAS LIMITED

TITLE:

Base of Oilsands

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 21/10
PROJECT:	07-104

FIGURE: **B.3.3-3**



PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

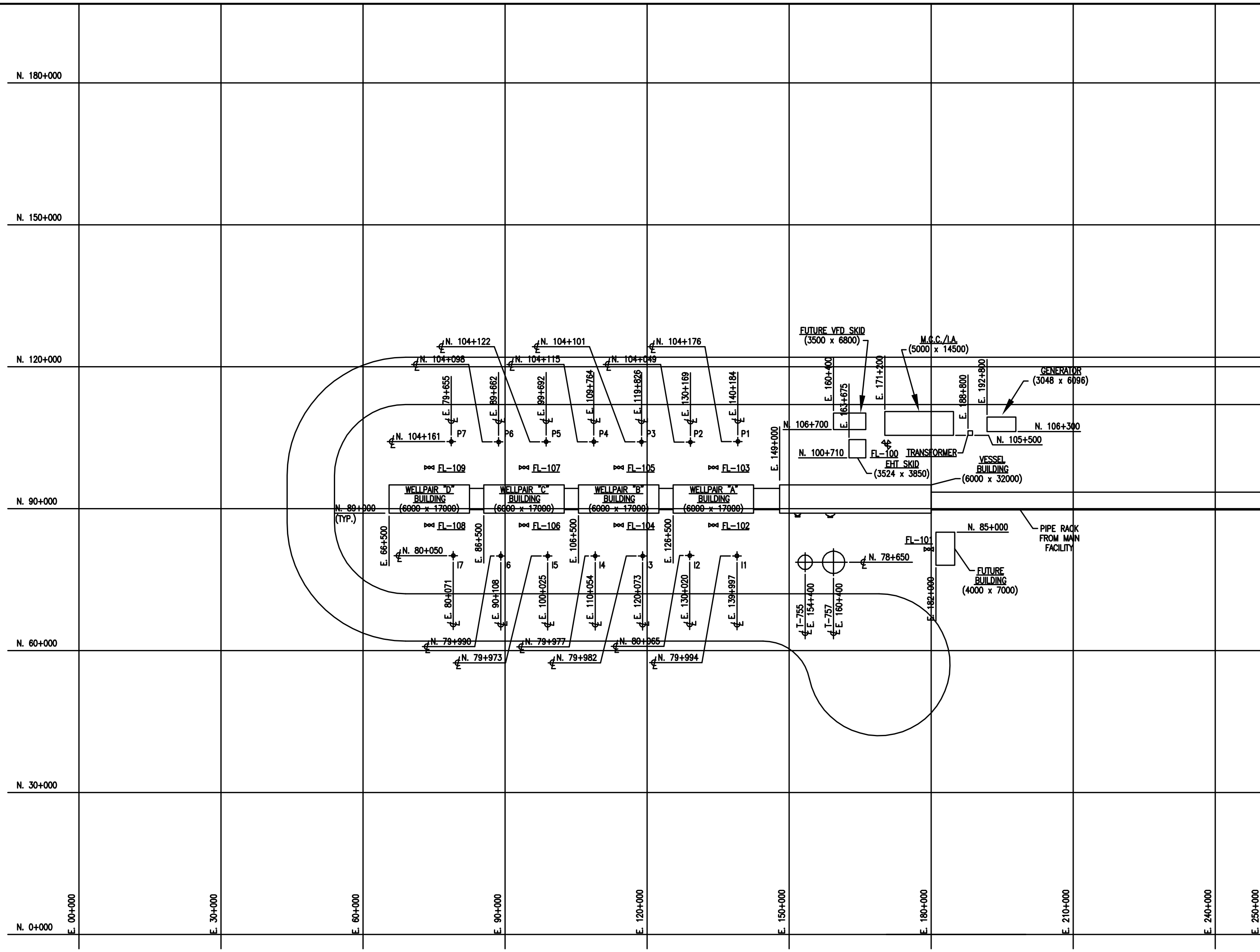
TITLE:

Core Photos of Caprock from LSD5-19-082-11-W5

DRAWN:	SL
CHECKED:	DM
DATE:	Apr 20/10
PROJECT:	07-104

FIGURE: **B.3.5-1**

REF: Connacher, 2007



GENERAL NOTES:

1. "POST CONSTRUCTION DRAWINGS" ARE GENERATED FROM CONSTRUCTION CHANGE INFORMATION FORWARDED TO AMEC BDR LIMITED BY THE OWNER'S FIELD SUPERVISORS AND OR HIRED CONTRACTORS. ANY CHANGES NOT DOCUMENTED WILL NOT APPEAR ON THE DRAWINGS AND THEREFORE THE DRAWING MAY NOT BE AN ACCURATE REPRESENTATION OF THE CONSTRUCTED FACILITY.
2. PRIOR TO THE COMMENCEMENT OF ANY CONSTRUCTION AND OR EXCAVATION IT SHALL BE THE RESPONSIBILITY OF THE OWNERS REPRESENTATIVE TO VERIFY THE LOCATION AND STATUS OF ANY PIPING, ELECTRICAL, EQUIPMENT OR BUILDINGS.
3. ANY REVISIONS MADE TO EXISTING EQUIPMENT, PIPING OR ELECTRICAL ON A FACILITY NOT DESIGNED BY AMEC BDR LIMITED IS ONLY SHOWN AS A REPRESENTATION OF WHAT EXISTS AND MUST BE VERIFIED BY THE OWNER.

0 25 50m

Scale 1 : 1 250

Source: AMEC BDR Limited, 74429-A-00-04.dwg, REV. 0.

PROJECT:

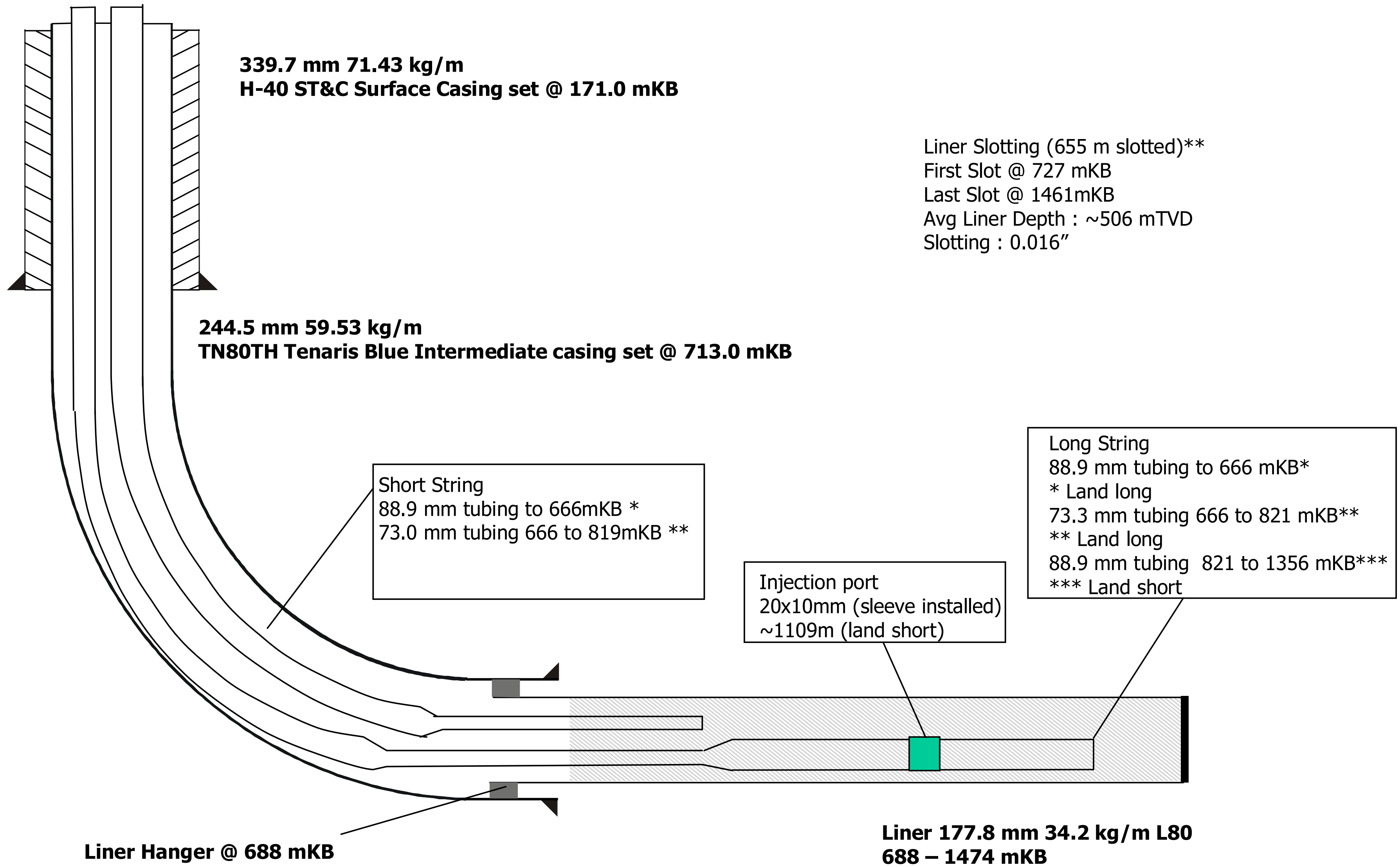
Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

FILE: ...Final Docs\Fig B.4.1-1 Well Pad Schematic.dwg

Typical Well Pad Schematic

DRAWN:	Others	FIGURE:
CHECKED:	DM	**B.4.1-1**
DATE:	May 3/10	
PROJECT:	07-104	



PROJECT:

Great Divide SAGD Expansion Project

Connacher OIL AND GAS LIMITED

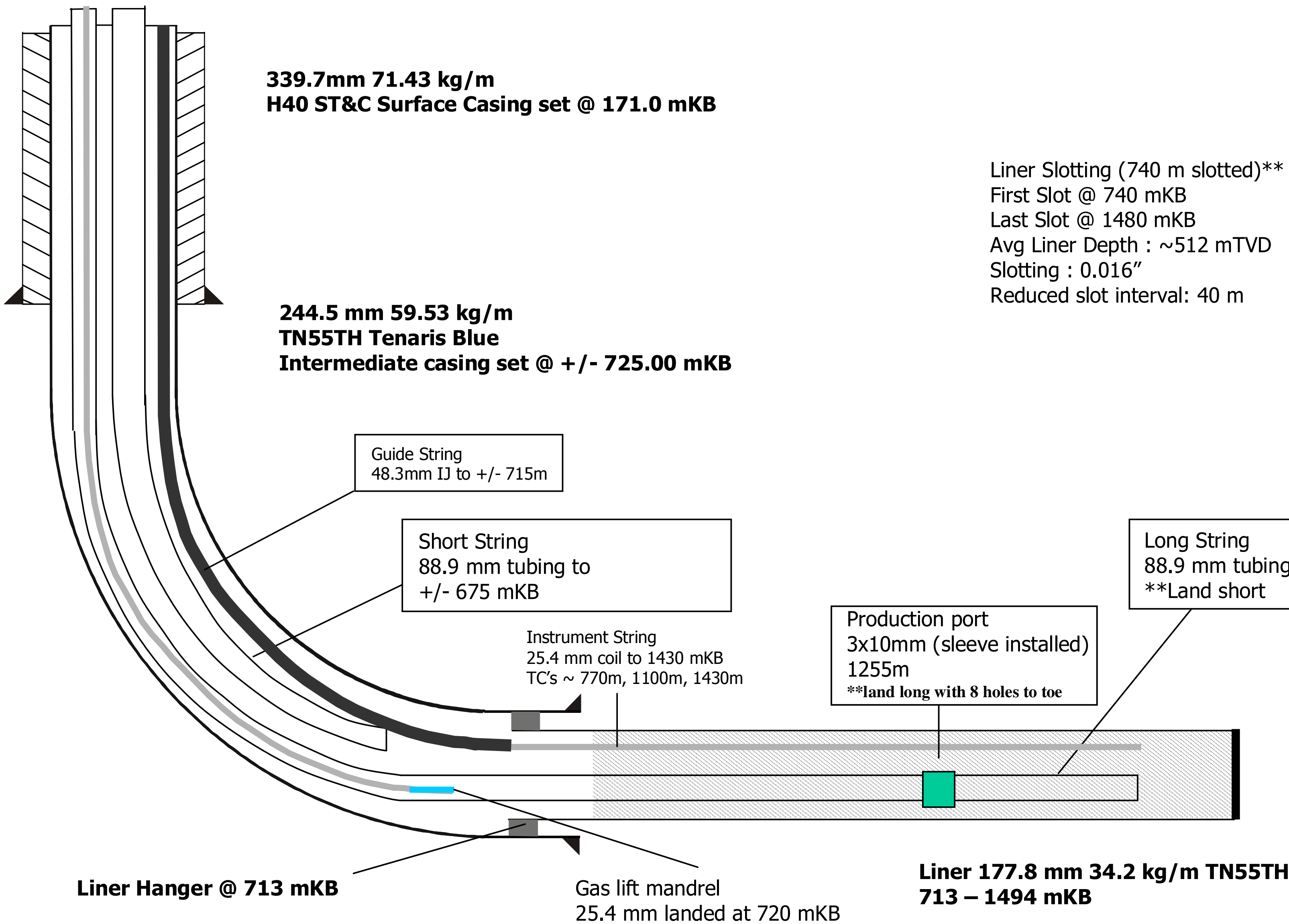
TITLE:

Typical Injection Well Schematic

DRAWN: SL
CHECKED: DM
DATE: May 5/10
PROJECT: 07-104

FIGURE: **B.4.2-1**

REF: Connacher, 2010.



REF: Connacher, 2010.

PROJECT: **Great Divide SAGD Expansion Project**

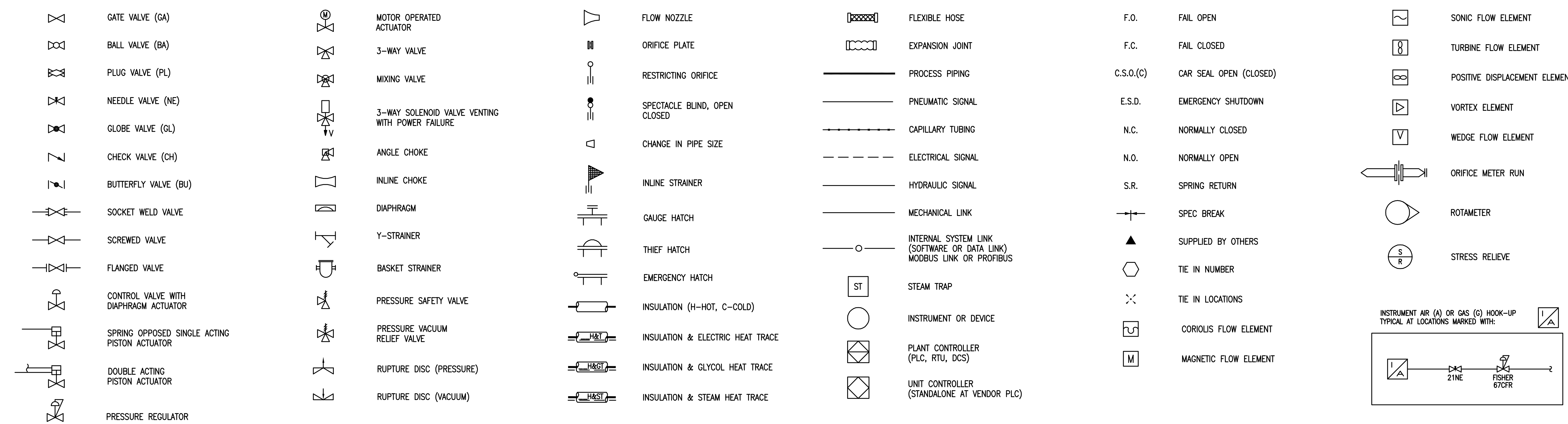
Connacher OIL AND GAS LIMITED

TITLE: **Typical Production Well Schematic**

DRAWN: SL
CHECKED: DM
DATE: May 5/10
PROJECT: 07-104

FIGURE: **B.4.2-2**

SYMBOL LEGEND



INSTRUMENT BALLOON LETTERING LEGEND

NOTE: WHEN AN INSTRUMENT IS CLASSIFIED WITH ONLY TWO LETTERS, USE THE FIRST AND THIRD LETTER MEANINGS.
WHEN AN INSTRUMENT IS CLASSIFIED WITH ONLY ONE LETTER, USE THE SECOND LETTER MEANINGS.

1ST. LETTER	MEANING(S)	2ND. LETTER	MEANING(S)	3RD. LETTER	MEANING(S)
A	ANALYZE, ACTUATE	A	ALARM	A	ALARM
B	BURNER	B	–	B	–
BD	BLOWDOWN	BD	–	BD	–
C	COMBUSTIBLE, CONCENTRATION	C	CONTROL	C	CONTROLLER, CLOSED
D	DEW, MOISTURE	D	DETECT	D	DETECT, DEVICE
E	VOLTAGE, EMERGENCY	E	–	E	ELEMENT
F	FLOW	F	RATIO, FRACTIONAL	F	FORWARD
FF	FLAME FAILURE	FF	–	FF	–
G	GAS	G	–	G	GLASS, GAUGE
H	HAND	H	–	H	HATCH, HIGH
I	ELECTRICAL CURRENT	I	INDICATOR, IGNITOR	I	INDICATOR, IGNITOR
J	POWER	J	–	J	–
K	TIME, TIME SCHEDULE	K	–	K	CONTROL STATION
L	LEVEL	L	–	L	LOW
M	MOTOR	M	MOMENTARY	M	MANAGE(R)
N	USERS CHOICE	N	USERS CHOICE	N	USERS CHOICE
O	USERS CHOICE	O	USERS CHOICE	O	ORIFICE, OPEN
P	PRESSURE, VACUUM	P	POINT/TEST CONNECTION	P	–
PD	PRESSURE DIFFERENTIAL	PD	–	PD	–
PV	PRESSURE & VACUUM	PV	–	PV	–
Q	QUANTITY	Q	TOTALIZE, INTEGRATE	Q	–
R	RADIATION, RESTRICT	R	RECORD, REGULATE, RUN, RELIEF	R	RECORD, REVERSE, RUN
S	SPEED, FREQUENCY, SOLENOID, SURGE	S	SAFETY, SCAN, STOP/START, SWITCH	S	SWITCH, SYSTEM, STATUS
SD	SHUTDOWN	SD	SHUTDOWN	SD	SHUTDOWN
T	TEMPERATURE, THIEF	T	–	T	TRANSMITTER
TD	TEMPERATURE DIFFERENTIAL	TD	–	TD	–
U	MULTIVARIABLE, UNIT	U	MULTIFUNCTION	U	MULTIFUNCTION
V	VIBRATION	V	VACUUM	V	VALVE, DAMPNER, LOUVRE
W	WEIGHT, FORCE	W	–	W	WELL
X	UNCLASSIFIED	X	UNCLASSIFIED	X	UNCLASSIFIED
Y	EVENT, STATE, PRESENCE	Y	CONVERT, COMPUTE, RELAY	Y	–
Z	POSITION	Z		Z	UNCLASSIFIED, FCE (FINAL CONTROL ELEMENT)

VALVE DESIGNATIONS

114 BA- 1 0 1 S X

VALVE SIZE

VALVE TYPE
BA-BALL
BS-BASKET STRAINER
BU-BUTTERFLY
CH-CHECK
GA-GATE
GL-GLOBE
NE-NEEDLE
PL-PLUG
YS-Y STRAINER

RATING
1-150# ANSI
3-300# ANSI
6-600# ANSI
9-900# ANSI
15-1500# ANSI
25-2500# ANSI

BODY STYLE MODIFIER

END CONNECTIONS
1-RF FLANGED
2-RTJ FLANGED
3-THREADED
4-WELDED (SOCKET)
5-WELDED (BUTT)
6-MxF (GAUGE VALVES)
7-FLAT FACE FLANGED
8-CLAMP
9-WELDED (SOCKET) x THREADED

SOUR

TEMPERATURE SERVICE
V - BELOW -45°C
W - -45°C TO -29°C
X - -29°C TO 121°C
Y - 121°C TO 200°C
Z - ABOVE 200°C

BODY STYLE MODIFIER	0	1	2	3	4	5
BALL	R.P. FLOATING	F.P. FLOATING	R.P. TRUNNION	F.P. TRUNNION		
BUTTERFLY	RUBBER LINED NON-LUGGED	RUBBER LINED LUGGED	TFE SEATED NON-LUGGED	TFE SEATED LUGGED	METAL SEATED NON-LUGGED	METAL SEATED LUGGED
CHECK	F.P. SWING	R.P. SWING	WAFER TYPE SWING	PISTON TYPE	PISTON TYPE WAFER	
GATE	R.P. WEDGE	FLEX WEDGE	F.P. SLAB	R.P. SLAB	F.P. WEDGE	
GLOBE	STD. BODY	ANGLE BODY	"Y" BODY			
NEEDLE	THREADED BONNET METAL SEAT	THREADED BONNET SOFT SEAT	OS&Y BONNET METAL SEAT	OS&Y BONNET SOFT SEAT	GAUGE VALVE THREADED BONNET METAL SEAT	GAUGE VALVE THREADED BONNET SOFT SEAT
PLUG	REGULAR PATTERN	SHORT PATTERN	JACKET			
BASKET STRAINER						
"Y" STRAINER						

GENERAL NOTES:

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2. PRIOR TO THE COMMENCEMENT OF ANY CONSTRUCTION AND OR EXCAVATION IT SHALL BE THE RESPONSIBILITY OF THE OWNERS REPRESENTATIVE TO VERIFY THE LOCATION AND STATUS OF ANY PIPING, ELECTRICAL, EQUIPMENT OR BUILDINGS.
3. ANY REVISIONS MADE TO EXISTING EQUIPMENT, PIPING OR ELECTRICAL ON A FACILITY NOT DESIGNED BY B.D.R. ENG. LTD. IS ONLY SHOWN AS A REPRESENTATION OF WHAT EXISTS AND MUST BE VERIFIED BY THE OWNER.

LINE NUMBERING SYSTEM

114 -	150	C	PS	X	- 121
LINE SIZE (mm OD)	PRIMARY PRESSURE RATING	LINE MATERIAL CODE	PIPING SYSTEM CODE	TEMP. INDEX	LINE NUMBER

PRIMARY PRESSURE RATING

CLASS	RATING
150	ANSI 150#
300	ANSI 300#
600	ANSI 600#
900	ANSI 900#
1500	ANSI 1500#
2500	ANSI 2500#

LINE MATERIAL CODE

COATED PIPING	C
FIBRE GLASS	F
STAINLESS STEEL	S
POLY	P

PIPING SYSTEM CODE

SERVICE	SYMBOL
INSTRUMENT AIR	IA
PROCESS PIPING (ANSI B31.3 CODE)	
- SWEET PROCESS HYDROCARBONS, CAUSTIC, PROCESS DRAINS, AND VENT SYSTEMS	P
- SOUR PROCESS HYDROCARBONS, CAUSTIC, SOUR LIQUIDS, HYDROCARBONS, AND WATER, PROCESS DRAINS, AND VENT SYSTEMS	PS

TEMPERATURE INDEX

SERVICE	SYMBOL
BELOW -45°C	V
-45°C TO -29°C	W
-29°C TO 121°C	X
121°C TO 200°C	Y
ABOVE 200°C	Z

STAMPS

PROJECT:
Great Divide SAGD Expansion Project

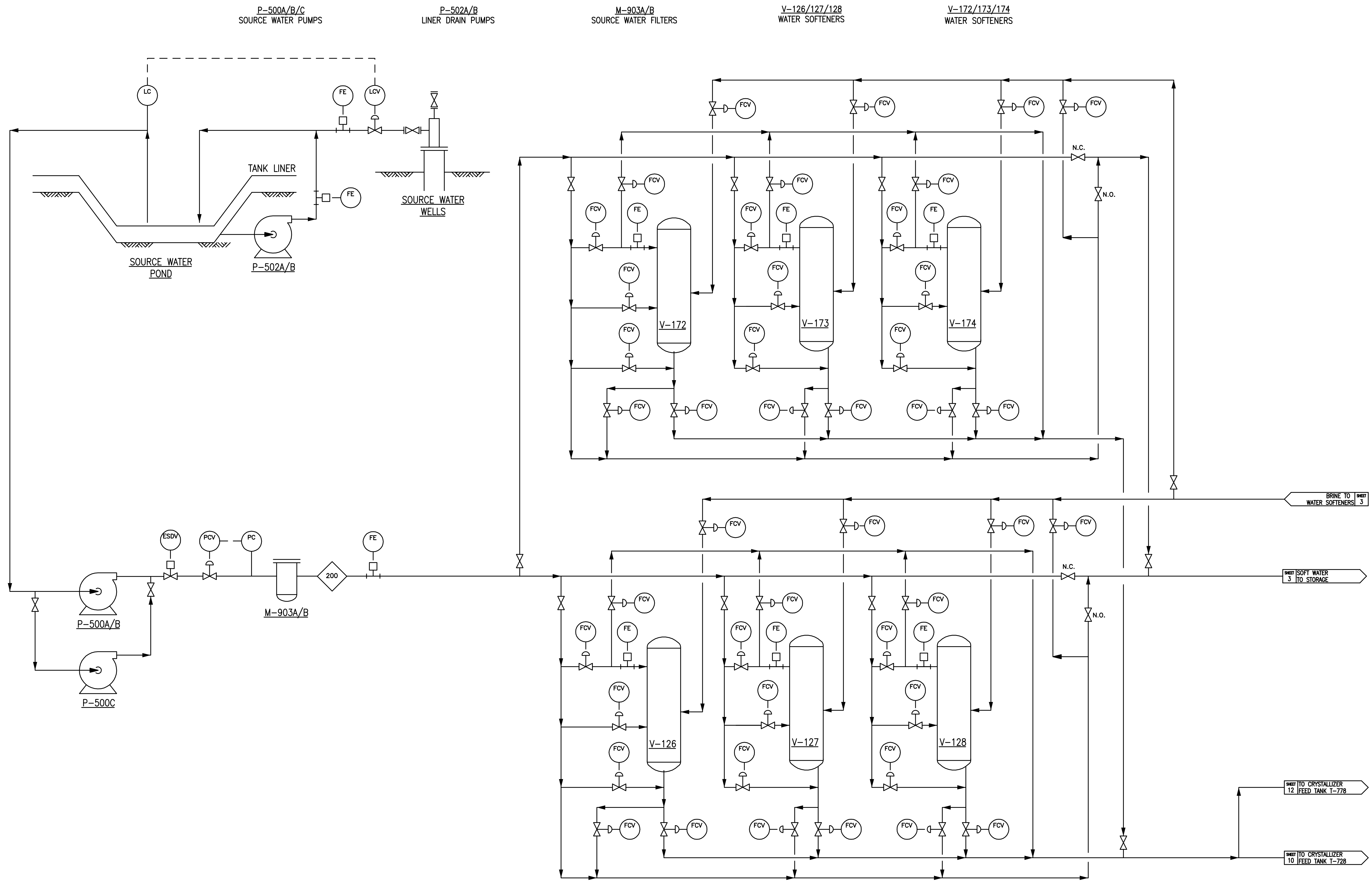
Connacher
OIL AND GAS LIMITED

FILE: ...Final Docs\Fig B.5.0-1 Water_Steam.dwg

Process Flowsheets for Water and Steam

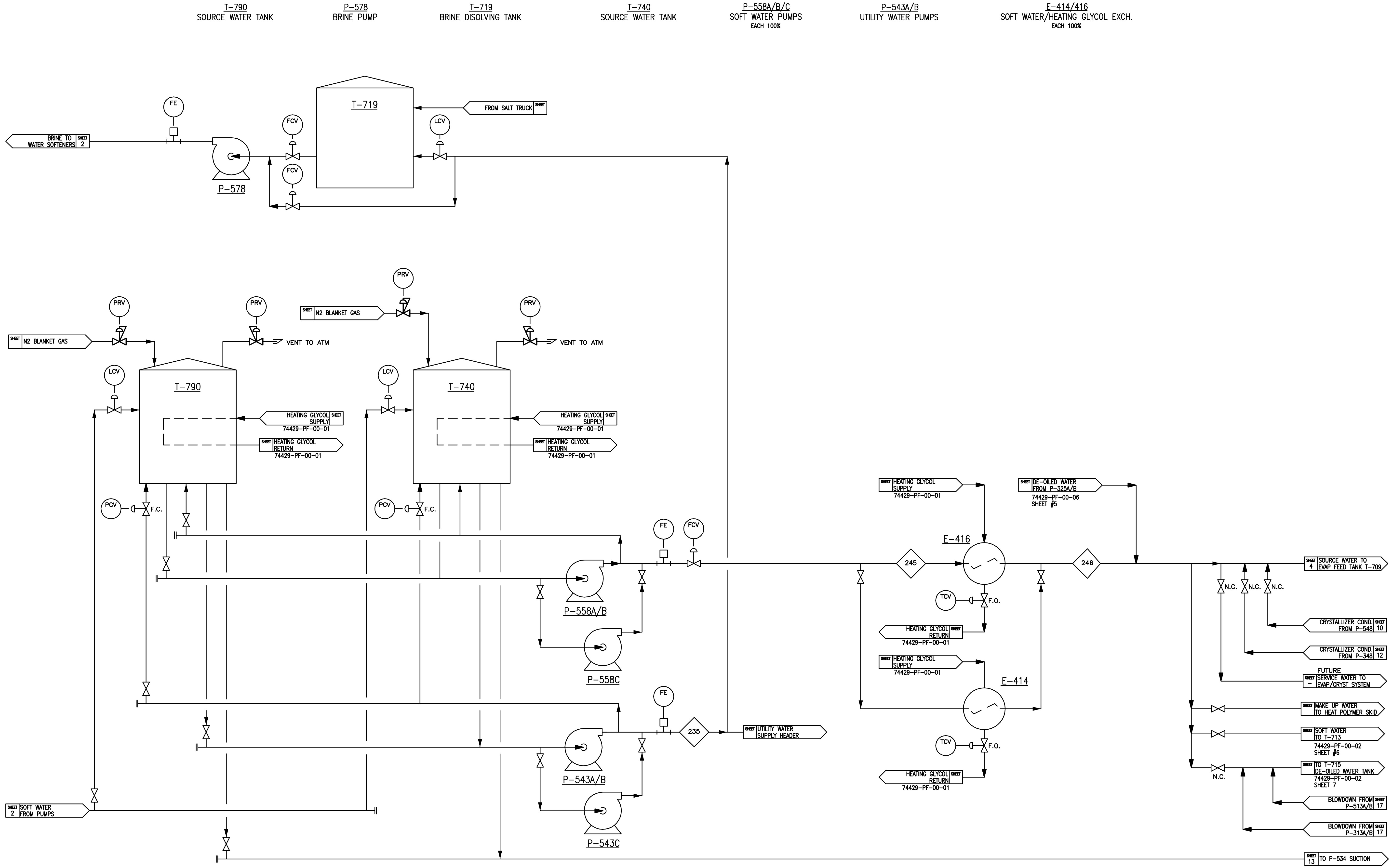
DRAWN:	Others	SHEET NUMBER:	1 of 17
CHECKED:	DM		
DATE:	May 3/10	FIGURE:	B.5.0-1
PROJECT:	07-104		

Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

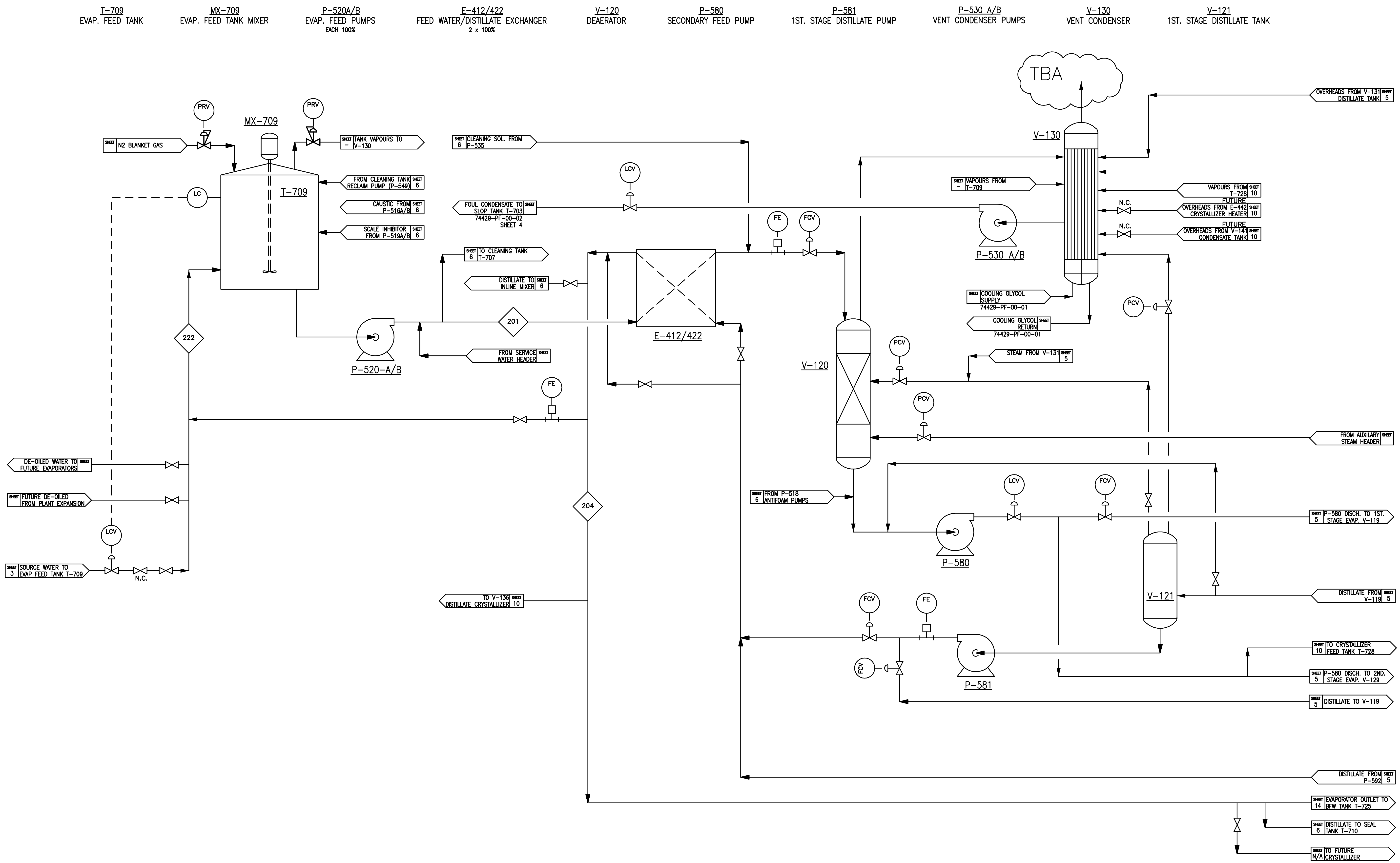
SHEET NUMBER: 2 of 17
FIGURE: B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

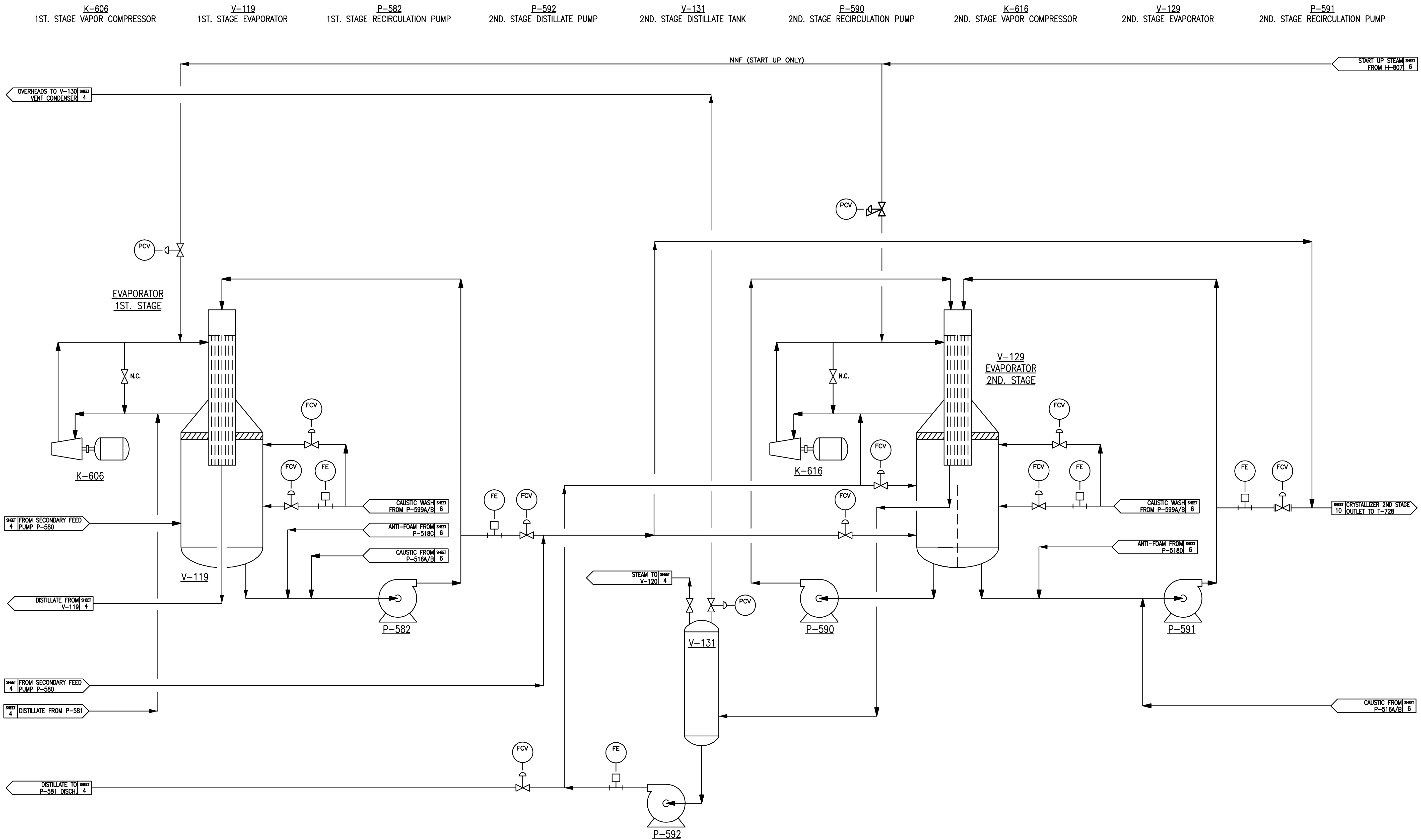
SHEET NUMBER:
3 of 17

FIGURE:
B.5.0-1



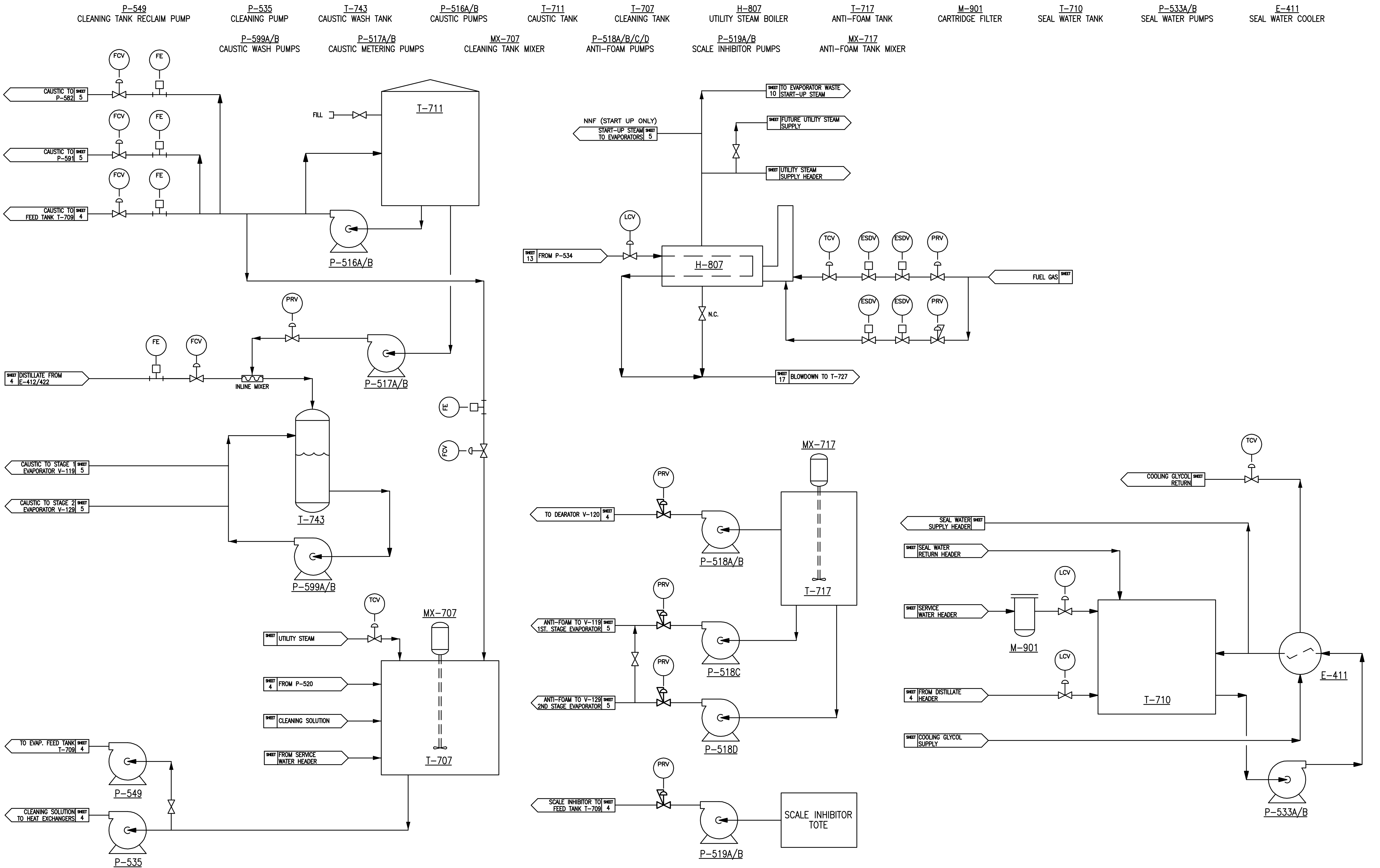
Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

SHEET NUMBER:
4 of 17
FIGURE:
B.5.0-1



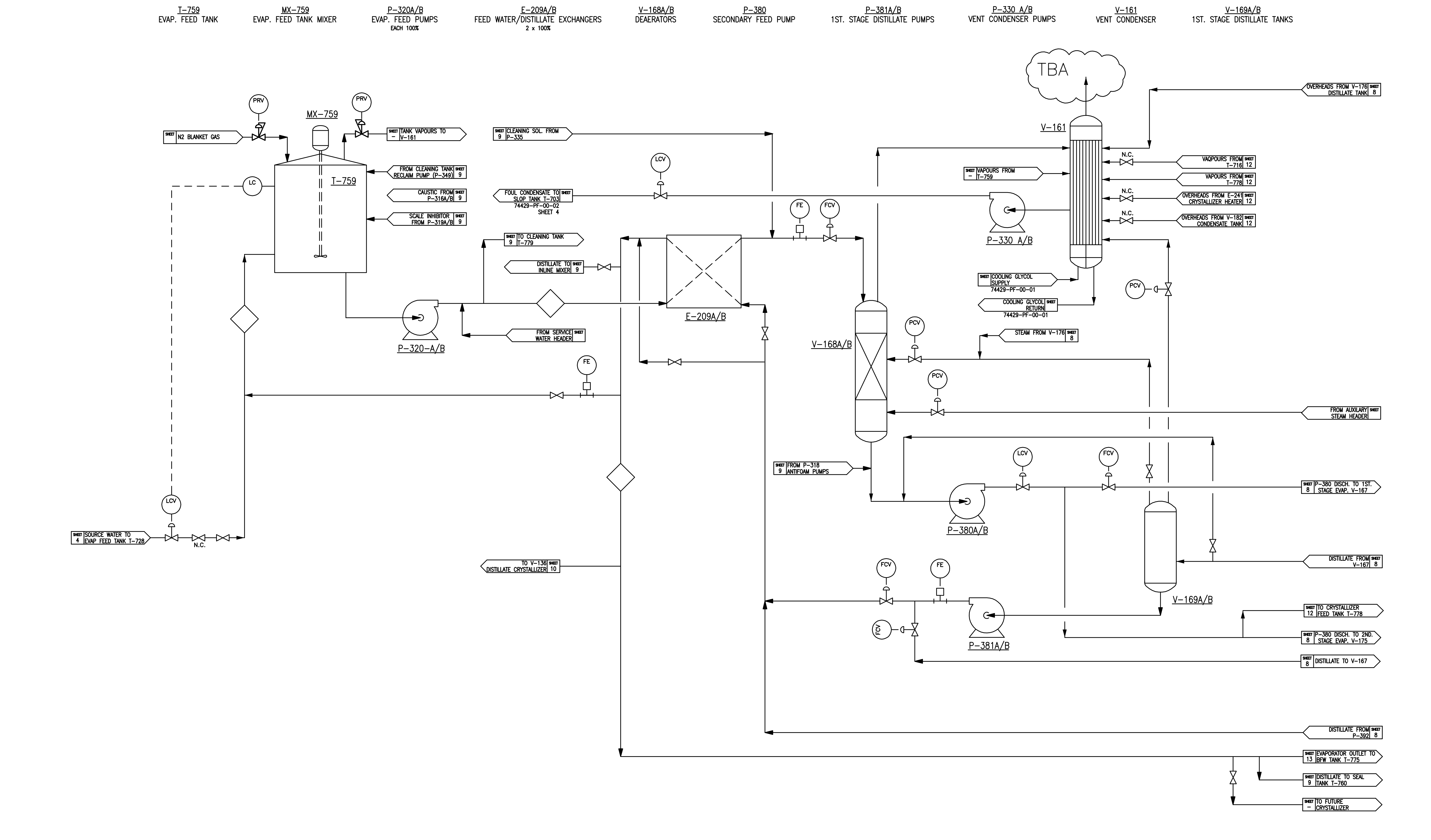
Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

SHEET NUMBER:
5 of 17
FIGURE:
B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

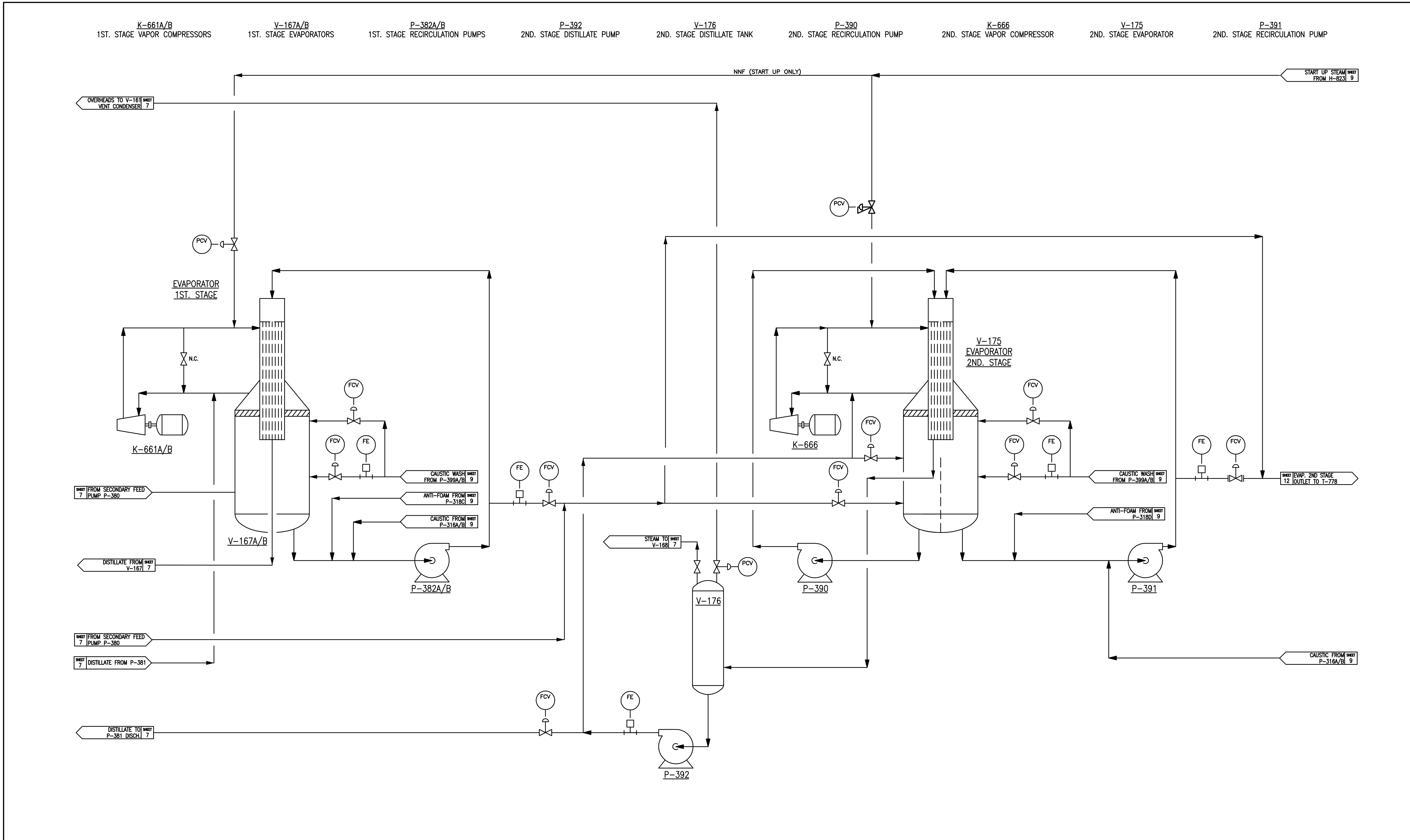
SHEET NUMBER:
6 of 17
FIGURE:
B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

SHEET NUMBER:
7 of 17

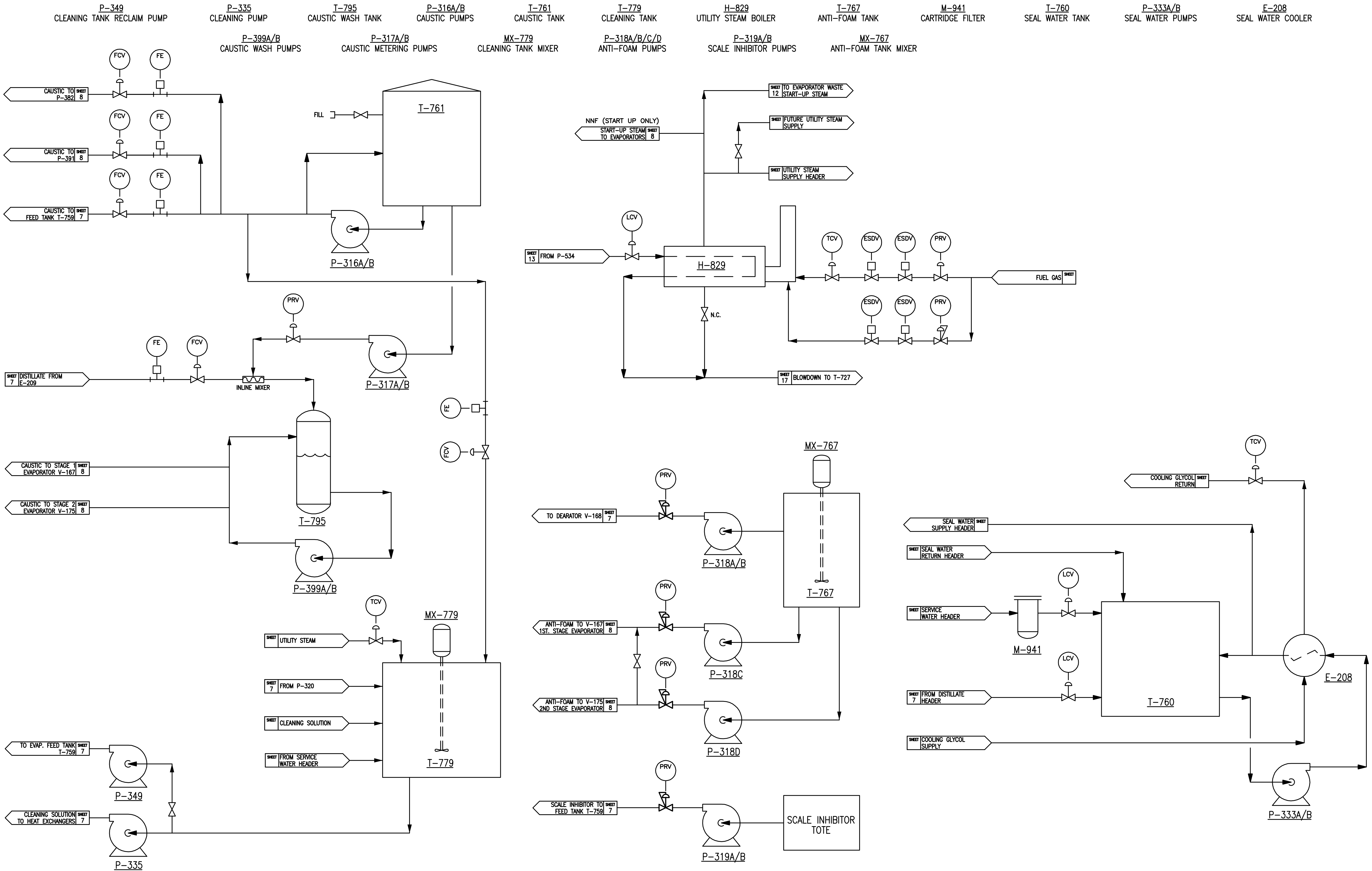
FIGURE:
B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

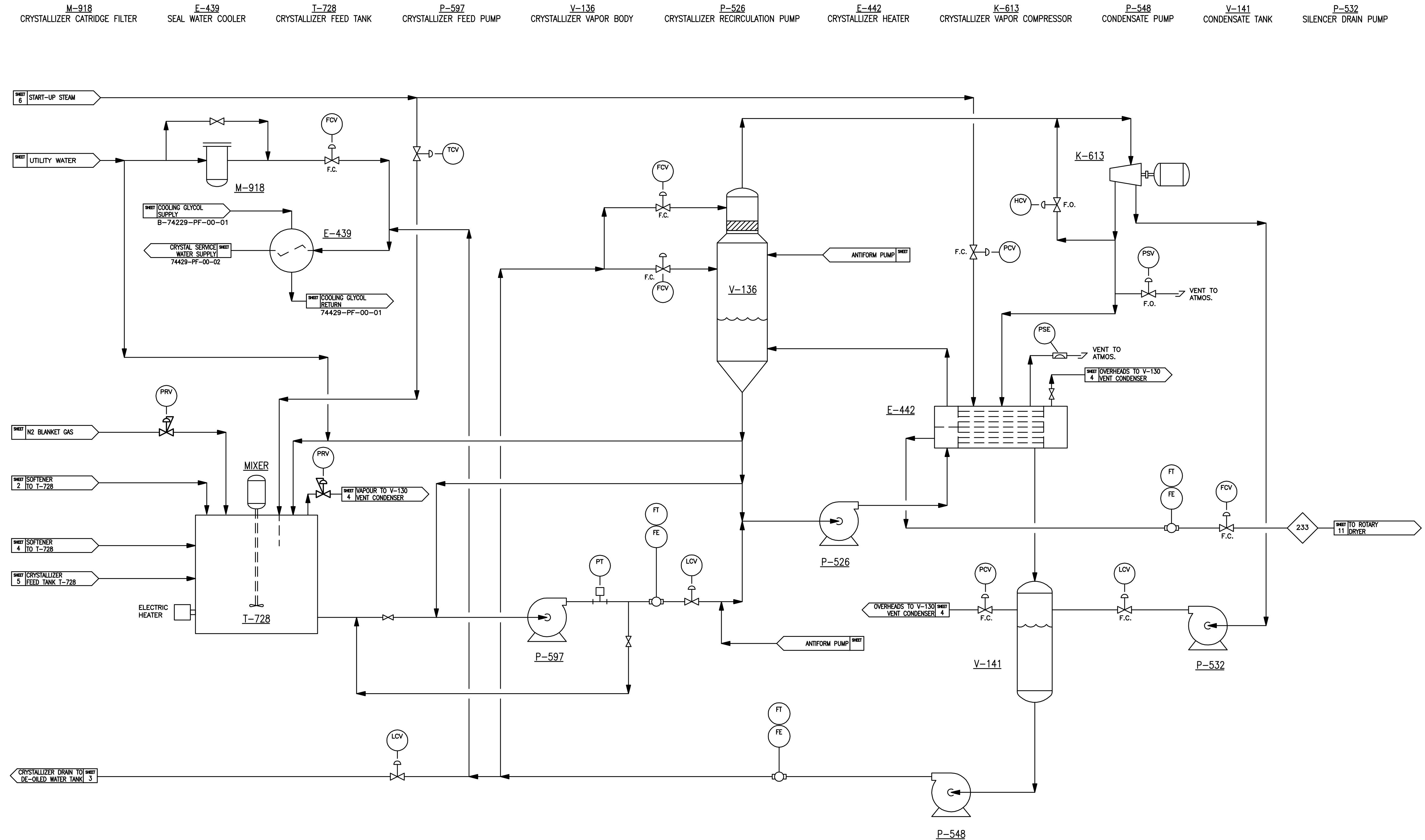
SHEET NUMBER:
8 of 17

FIGURE:
B.5.0-1



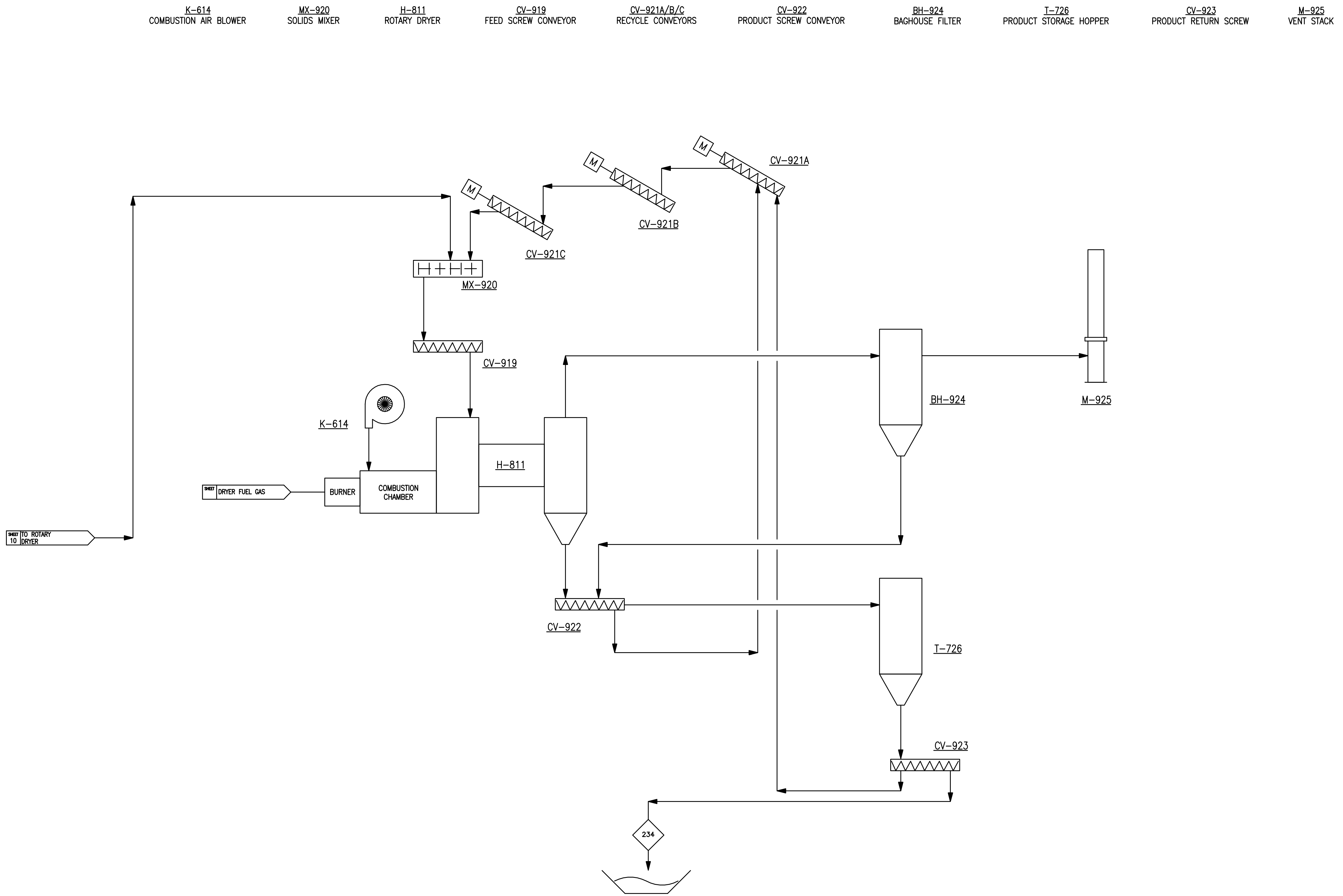
Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

SHEET NUMBER:
9 of 17
FIGURE:
B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

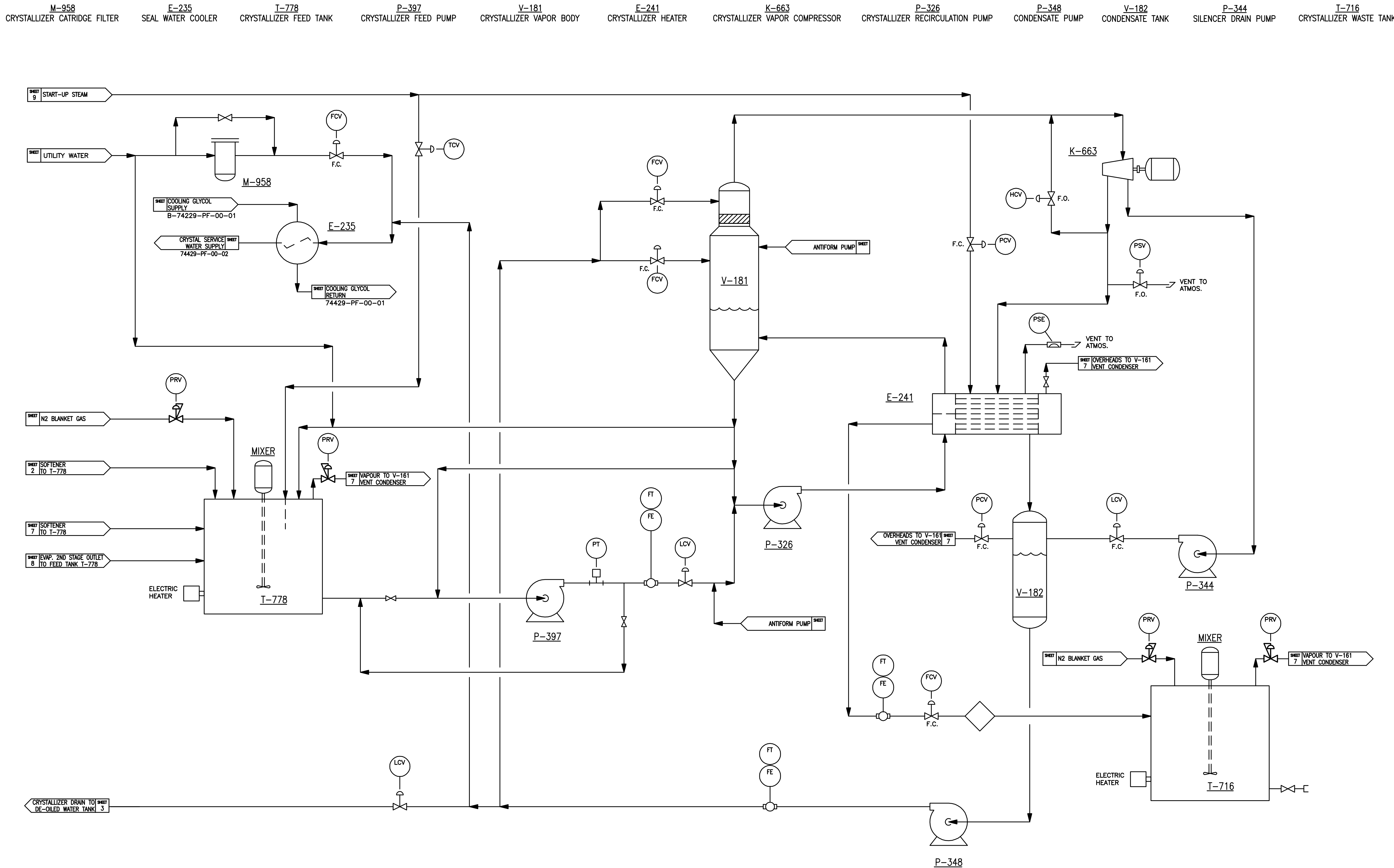
FIGURE:
B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

SHEET NUMBER: 11 of 17

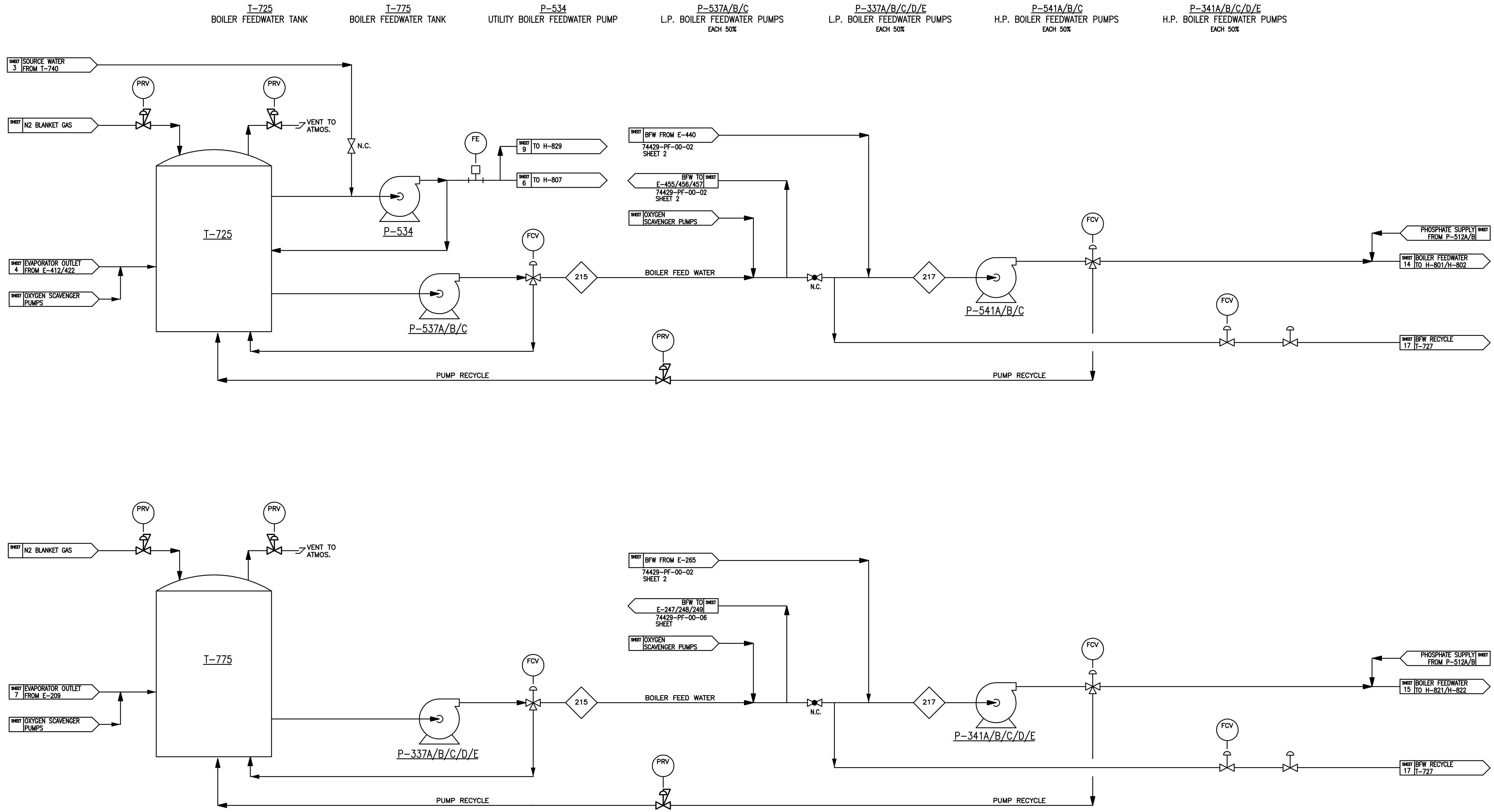
FIGURE: B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

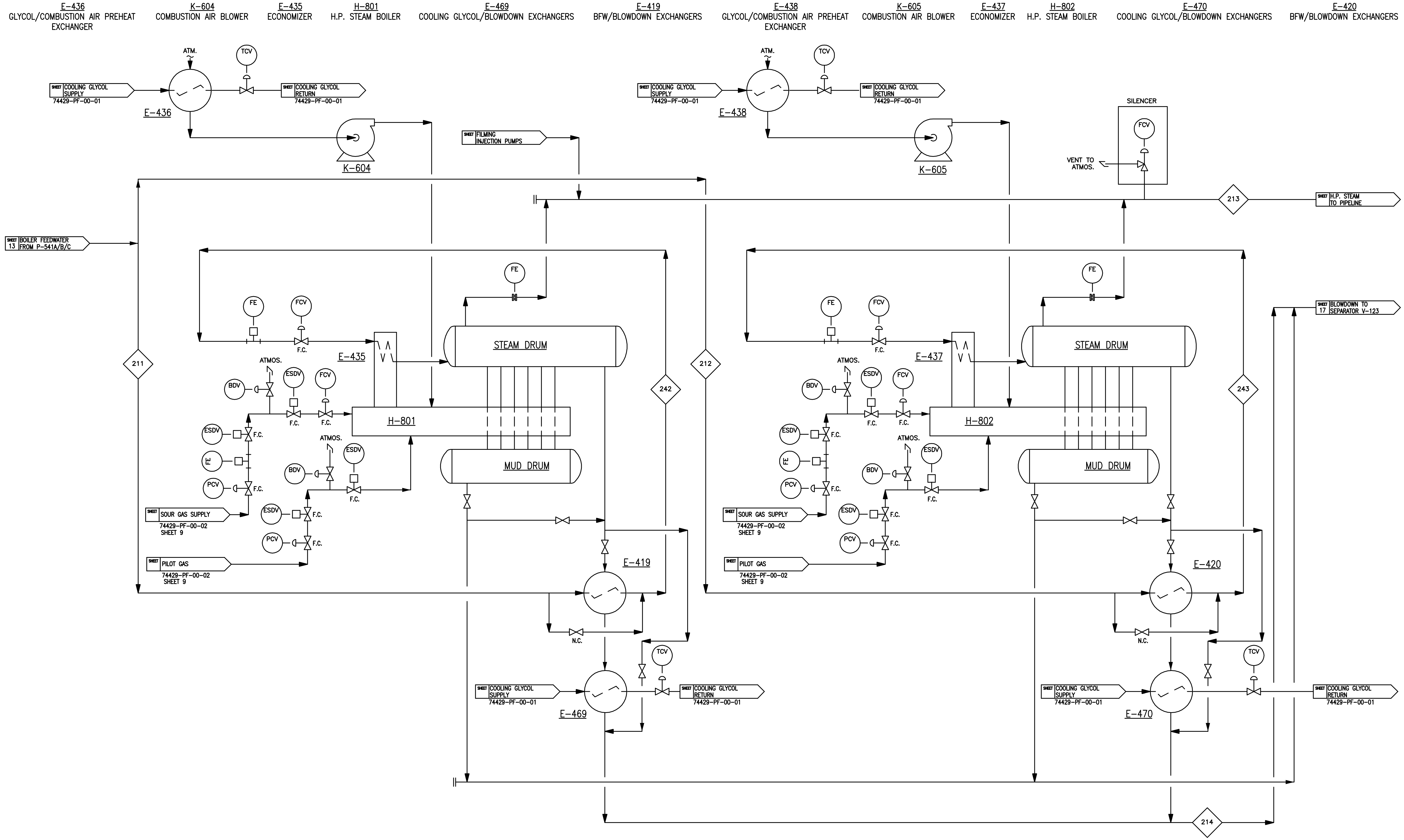
SHEET NUMBER:
12 of 17

FIGURE:
B.5.0-1



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

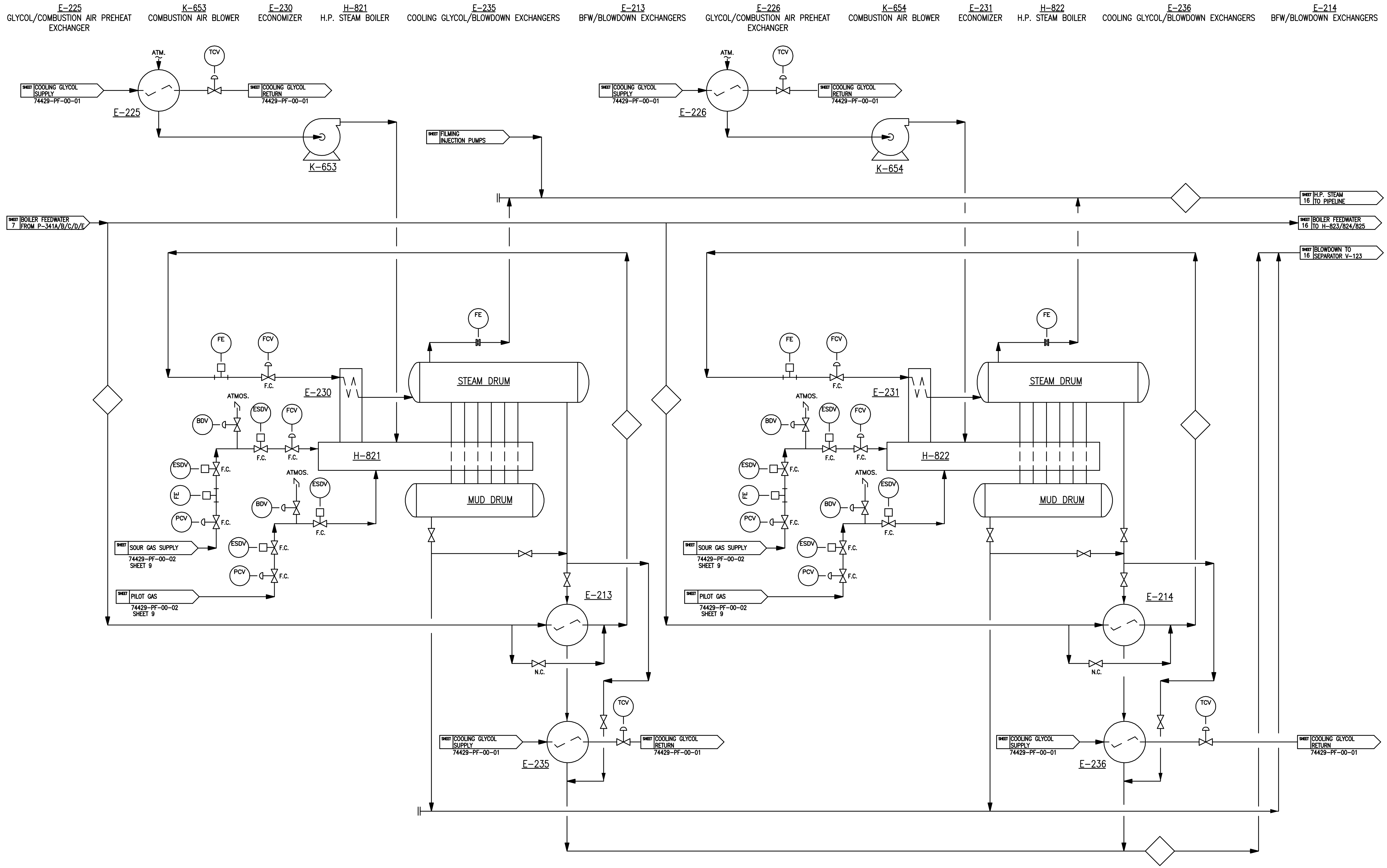
SHEET NUMBER:
13 of 17
FIGURE:
B.5.0-1



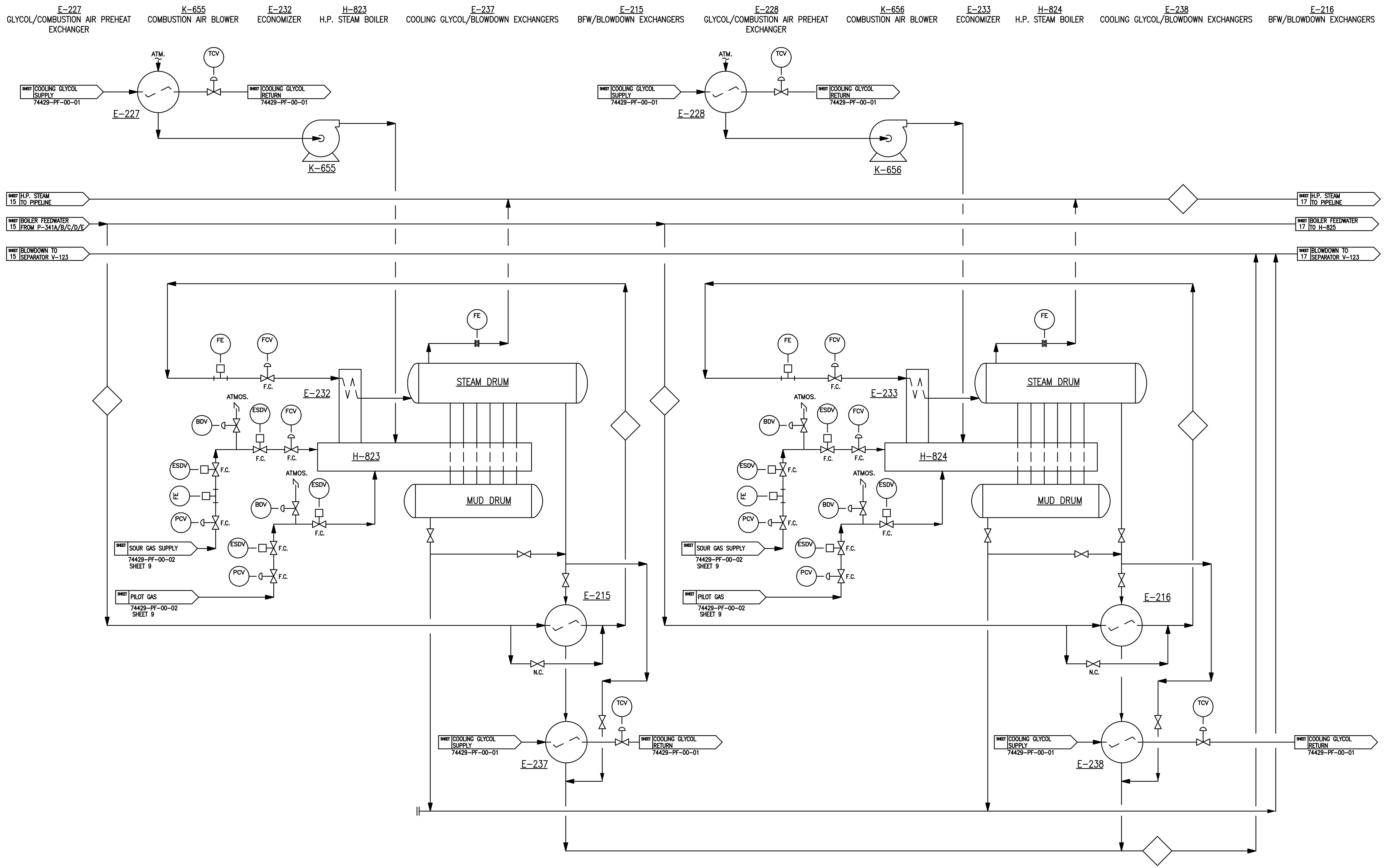
Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev.1.

SHEET NUMBER: 14 of 17

FIGURE: B.5.0-1



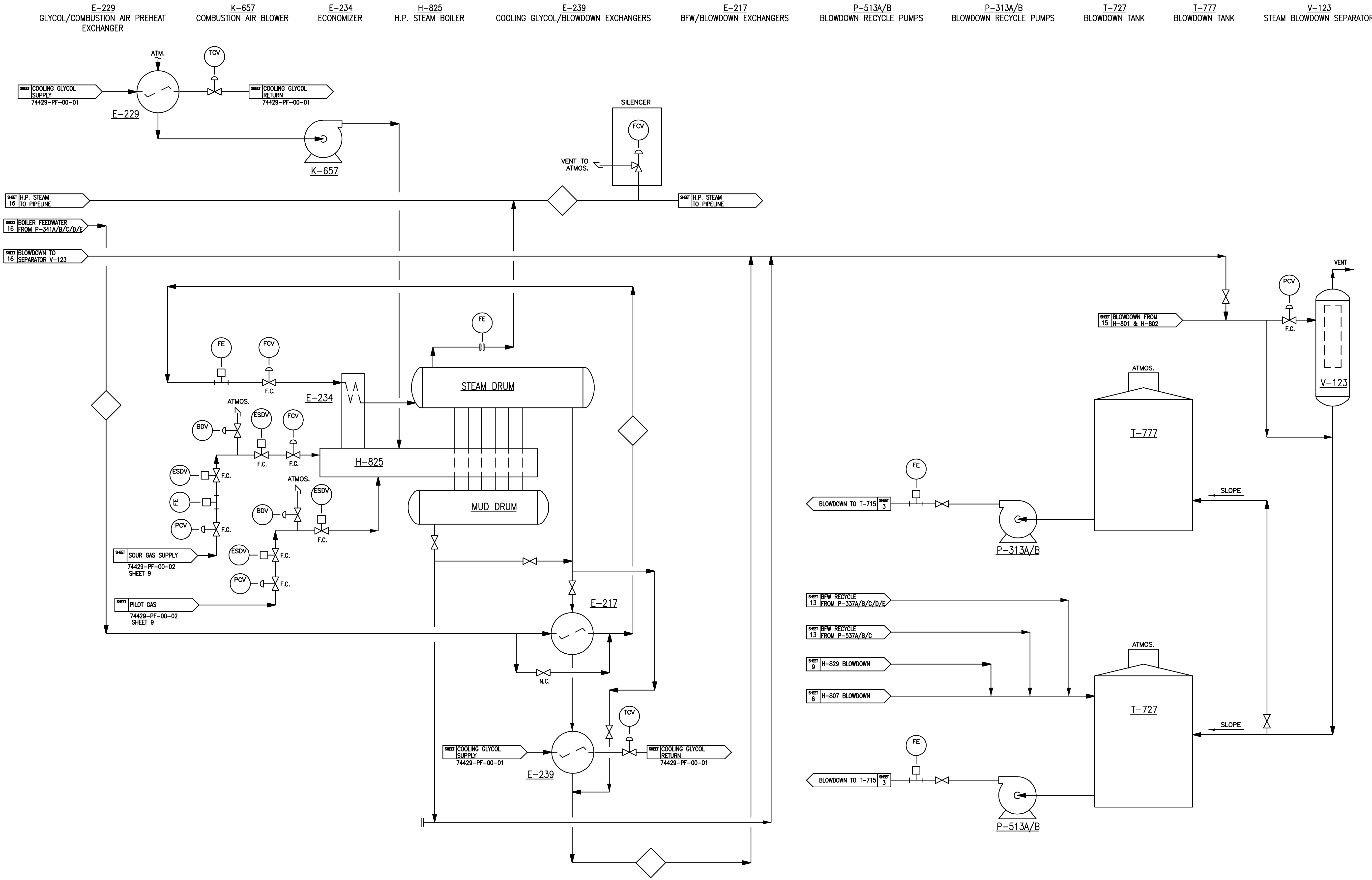
Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.



Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

SHEET NUMBER: 16 of 17

FIGURE: B.5.0-1

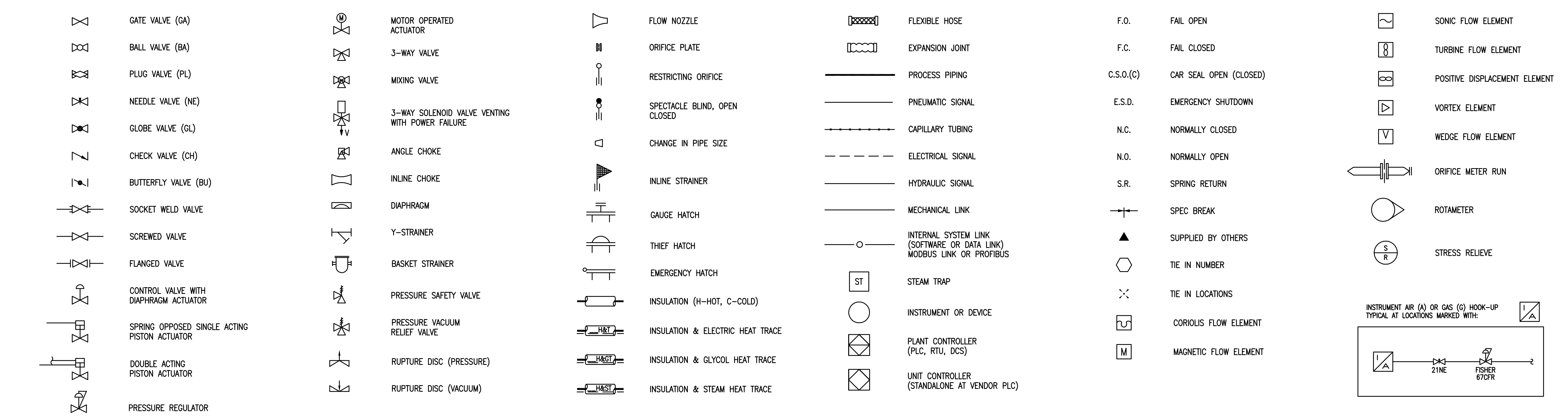


SHEET NUMBER: 17 of 17

FIGURE: B.5.0-1

Source: BDR Engineering Ltd., 74429-PF-00-07.dwg, Rev. 1.

SYMBOL LEGEND



INSTRUMENT BALLOON LETTERING LEGEND

NOTE: WHEN AN INSTRUMENT IS CLASSIFIED WITH ONLY TWO LETTERS, USE THE FIRST AND THIRD LETTER MEANINGS.
WHEN AN INSTRUMENT IS CLASSIFIED WITH ONLY ONE LETTER, USE THE SECOND LETTER MEANINGS.

1ST. LETTER	MEANING(S)	2ND. LETTER	MEANING(S)	3RD. LETTER	MEANING(S)
A	ANALYZE, ACTUATE	A	ALARM	A	ALARM
B	BURNER	B	–	B	–
BD	BLOWDOWN	BD	–	BD	–
C	COMBUSTIBLE, CONCENTRATION	C	CONTROL	C	CONTROLLER, CLOSED
D	DEW, MOISTURE	D	DETECT	D	DETECT, DEVICE
E	VOLTAGE, EMERGENCY	E	–	E	ELEMENT
F	FLOW	F	RATIO, FRACTIONAL	F	FORWARD
FF	FLAME FAILURE	FF	–	FF	–
G	GAS	G	–	G	GLASS, GAUGE
H	HAND	H	–	H	HATCH, HIGH
I	ELECTRICAL CURRENT	I	INDICATOR, IGNITOR	I	INDICATOR, IGNITOR
J	POWER	J	–	J	–
K	TIME, TIME SCHEDULE	K	–	K	CONTROL STATION
L	LEVEL	L	–	L	LOW
M	MOTOR	M	MOMENTARY	M	MANAGE(R)
N	USERS CHOICE	N	USERS CHOICE	N	USERS CHOICE
O	USERS CHOICE	O	–	O	ORIFICE, OPEN
P	PRESSURE, VACUUM	P	POINT/TEST CONNECTION	P	–
PD	PRESSURE DIFFERENTIAL	PD	–	PD	–
PV	PRESSURE & VACUUM	PV	–	PV	–
Q	QUANTITY	Q	TOTALIZE, INTEGRATE	Q	–
R	RADIATION, RESTRICT	R	RECORD, REGULATE, RUN, RELIEF	R	RECORD, REVERSE, RUN
S	SPEED, FREQUENCY, SOLENOID, SURGE	S	SAFETY, SCAN, STOP/START, SWITCH	S	SWITCH, SYSTEM, STATUS
SD	SHUTDOWN	SD	SHUTDOWN	SD	SHUTDOWN
T	TEMPERATURE, THIEF	T	–	T	TRANSMITTER
TD	TEMPERATURE DIFFERENTIAL	TD	–	TD	–
U	MULTIVARIABLE, UNIT	U	MULTIFUNCTION	U	MULTIFUNCTION
V	VIBRATION	V	VACUUM	V	VALVE, DAMPNER, LOUVRE
W	WEIGHT, FORCE	W	–	W	WELL
X	UNCLASSIFIED	X	UNCLASSIFIED	X	UNCLASSIFIED
Y	EVENT, STATE, PRESENCE	Y	CONVERT, COMPUTE, RELAY	Y	–
Z	POSITION	Z		Z	UNCLASSIFIED, FCE (FINAL CONTROL ELEMENT)

VALVE DESIGNATIONS

114 BA- 1 0 1 S X

VALVE SIZE

VALVE TYPE
BA–BALL
BS–BASKET STRAINER
BU–BUTTERFLY
CH–CHECK
GA–GATE
GL–GLOBE
NE–NEEDLE
PL–PLUG
YS–Y STRAINER

RATING
1–150# ANSI
3–300# ANSI
6–600# ANSI
9–900# ANSI
15–1500# ANSI
25–2500# ANSI

TEMPERATURE SERVICE
V – BELOW –45°C
W – –45°C TO –29°C
X – –29°C TO 121°C
Y – 121°C TO 200°C
Z – ABOVE 200°C

SOUR

END CONNECTIONS
1–RF FLANGED
2–RTJ FLANGED
3–THREADED
4–WELDED (SOCKET)
5–WELDED (BUTT)
6–MxF (GAUGE VALVES)
7–FLAT FACE FLANGED
8–CLAMP
9–WELDED (SOCKET) x THREADED

BODY STYLE MODIFIER

BODY STYLE MODIFIER	0	1	2	3	4	5
BALL	R.P. FLOATING	F.P. FLOATING	R.P. TRUNNION	F.P. TRUNNION		
BUTTERFLY	RUBBER LINED NON-LUGGED	RUBBER LINED LUGGED	TFE SEATED NON-LUGGED	TFE SEATED LUGGED	METAL SEATED NON-LUGGED	METAL SEATED LUGGED
CHECK	F.P. SWING	R.P. SWING	WAFER TYPE SWING	PISTON TYPE	PISTON TYPE WAFER	
GATE	R.P. WEDGE	FLEX WEDGE	F.P. SLAB	R.P. SLAB	F.P. WEDGE	
GLOBE	STD. BODY	ANGLE BODY	"Y" BODY			
NEEDLE	THREADED BONNET METAL SEAT	THREADED BONNET SOFT SEAT	OS&Y BONNET METAL SEAT	OS&Y BONNET SOFT SEAT	GAUGE VALVE THREADED BONNET METAL SEAT	GAUGE VALVE THREADED BONNET SOFT SEAT
PLUG	REGULAR PATTERN	SHORT PATTERN	JACKET			
BASKET STRAINER						
"Y" STRAINER						

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LINE NUMBERING SYSTEM

114 –	150	C	PS	X	– 121
LINE SIZE (mm OD)	PRIMARY PRESSURE RATING	LINE MATERIAL CODE	PIPING SYSTEM CODE	TEMP. INDEX	LINE NUMBER

PRIMARY PRESSURE RATING

CLASS	RATING
150	ANSI 150#
300	ANSI 300#
600	ANSI 600#
900	ANSI 900#
1500	ANSI 1500#
2500	ANSI 2500#

LINE MATERIAL CODE

COATED PIPING	C
FIBRE GLASS	F
STAINLESS STEEL	S
POLY	P

PIPING SYSTEM CODE

SERVICE	SYMBOL
INSTRUMENT AIR	IA
PROCESS PIPING (ANSI B31.3 CODE)	
– SWEET PROCESS HYDROCARBONS, CAUSTIC, PROCESS DRAINS, AND VENT SYSTEMS	P
– SOUR PROCESS HYDROCARBONS, CAUSTIC, SOUR LIQUIDS, HYDROCARBONS, AND WATER, PROCESS DRAINS, AND VENT SYSTEMS	PS

TEMPERATURE INDEX

SERVICE	SYMBOL
BELOW –45°C	V
–45°C TO –29°C	W
–29°C TO 121°C	X
121°C TO 200°C	Y
ABOVE 200°C	Z

STAMPS

PROJECT:
Great Divide SAGD Expansion Project

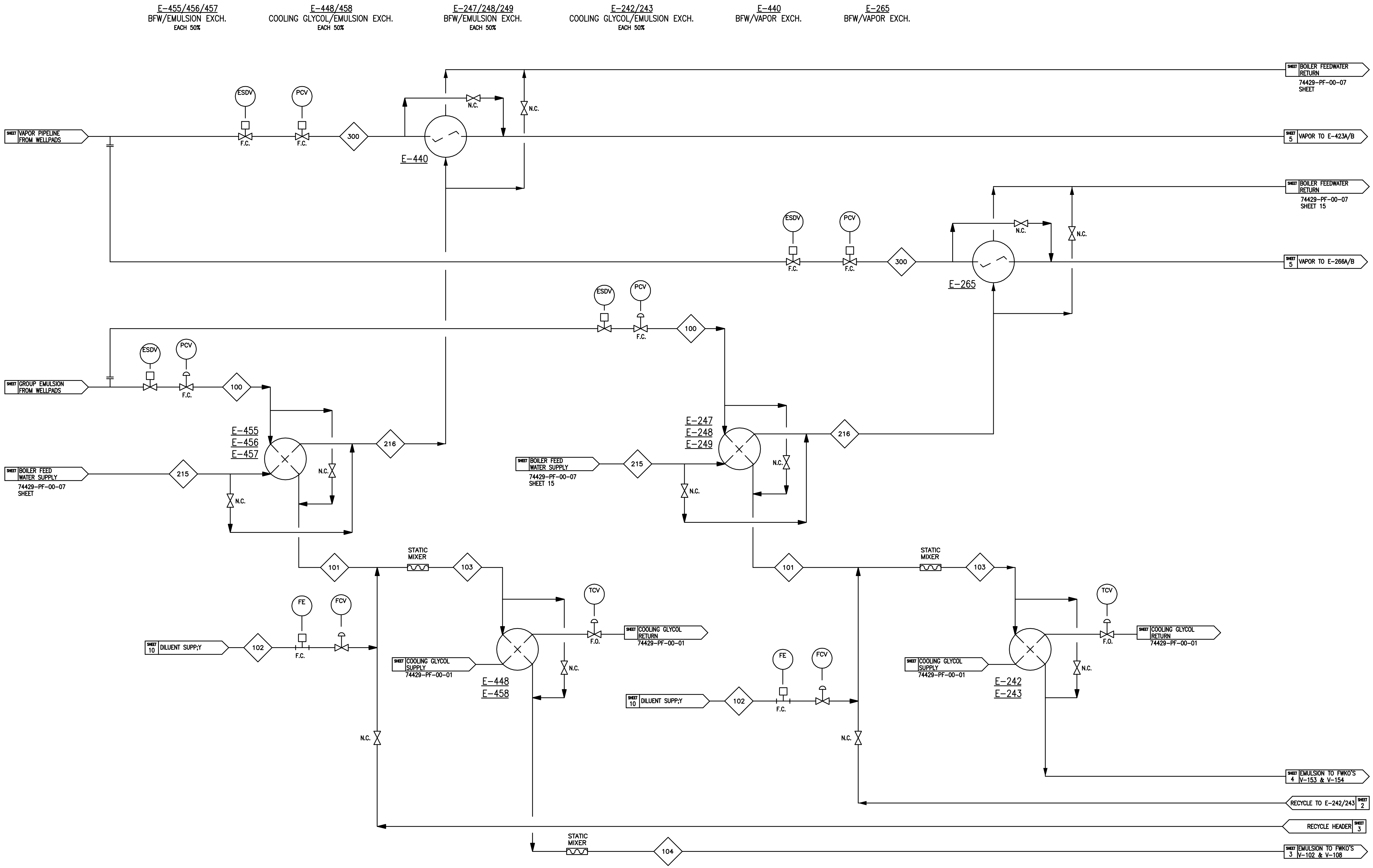
Process Flowsheets for Oil Treating

Connacher
OIL AND GAS LIMITED

FILE: ...Final Docs\Fig B.5.0-2 Oil Treating.dwg

DRAWN:	Others	SHEET NUMBER:	**1 of 13**
CHECKED:	DM		
DATE:	May 3/10	FIGURE:	**B.5.0-2**
PROJECT:	07-104		

Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

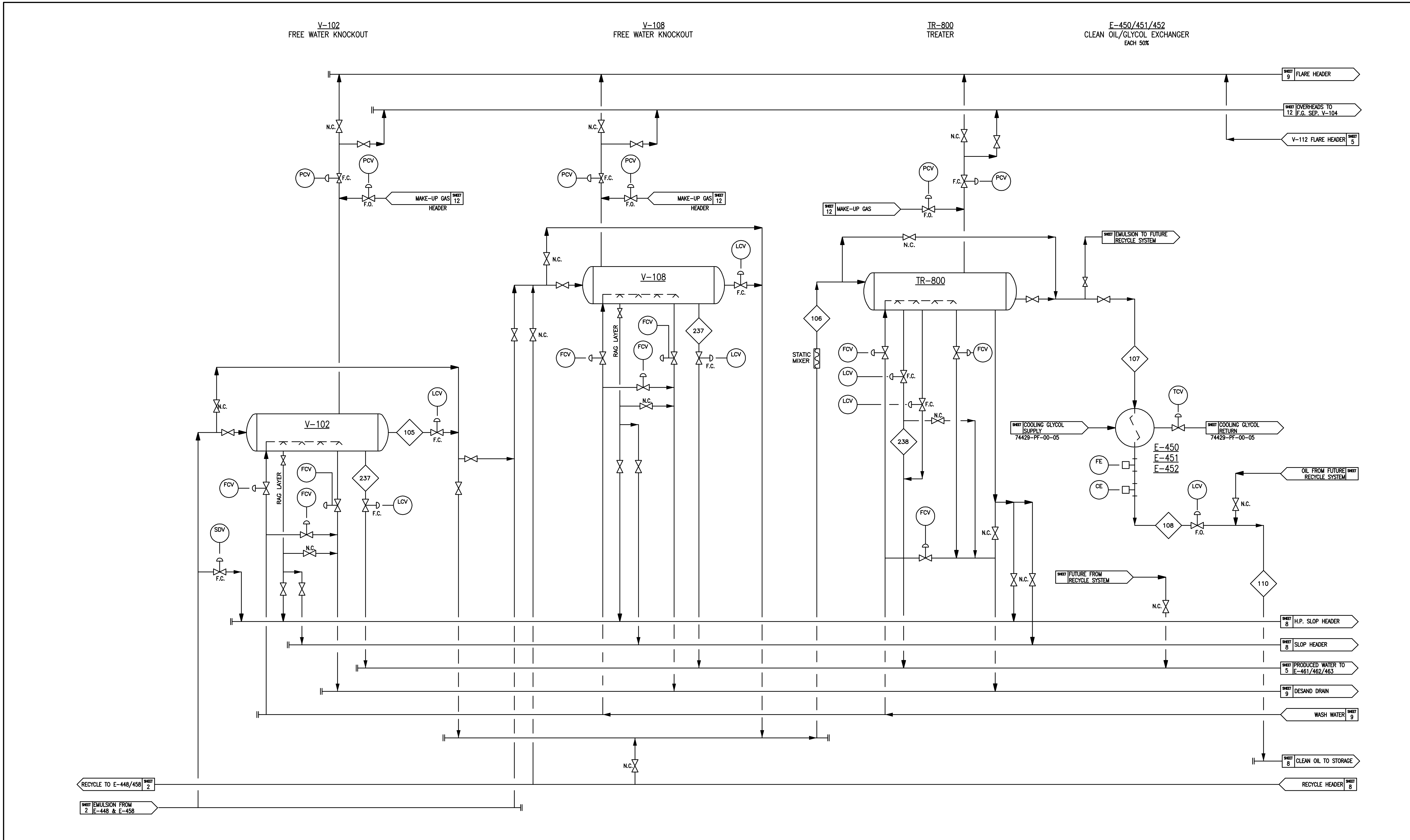


Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER: 2 of 13

FIGURE: B.5.0-2

Main Menu | Search | Main TOC

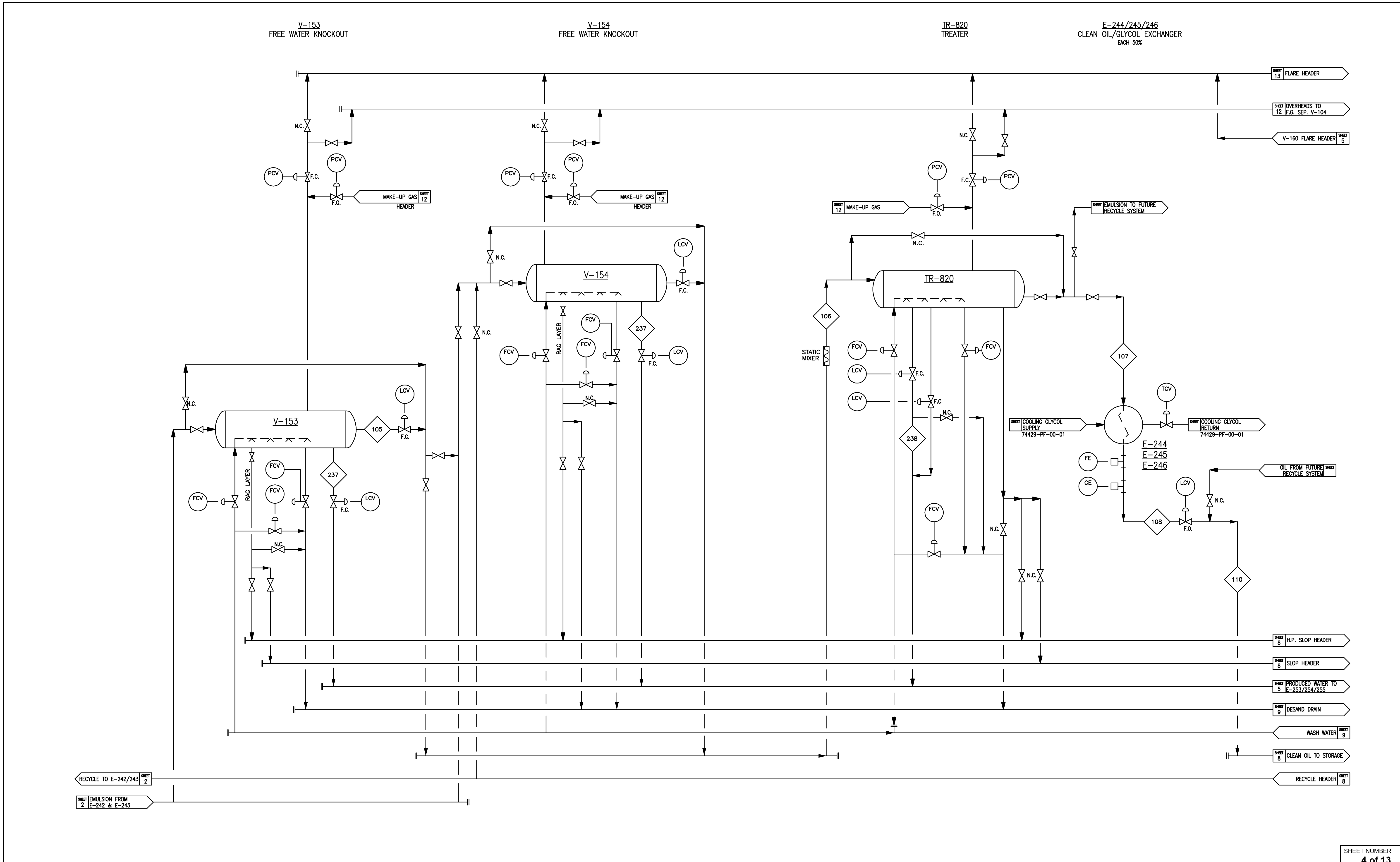


Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER:
3 of 13

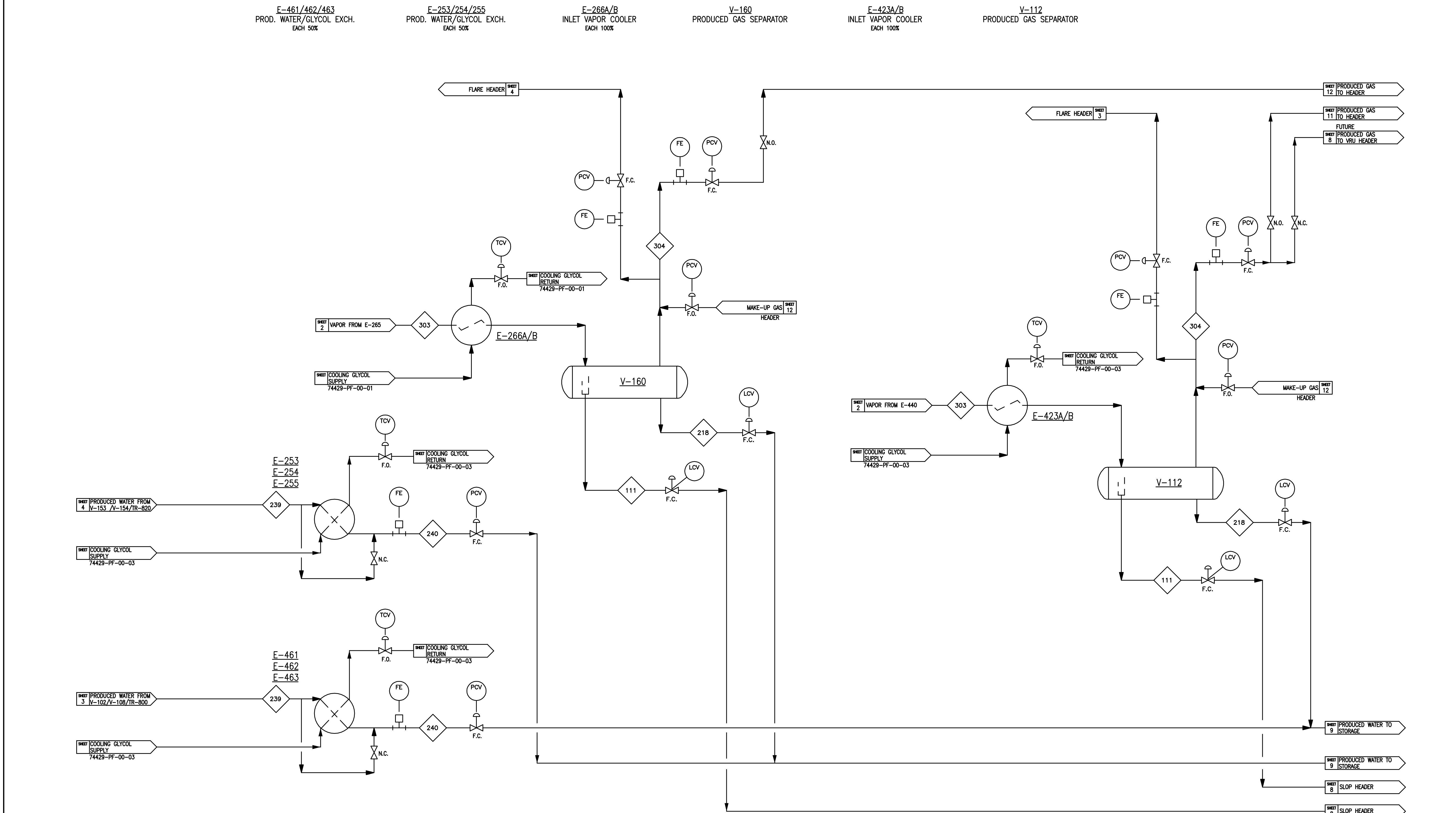
FIGURE:
B.5.0-2

Main Menu Search Main TOC



Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

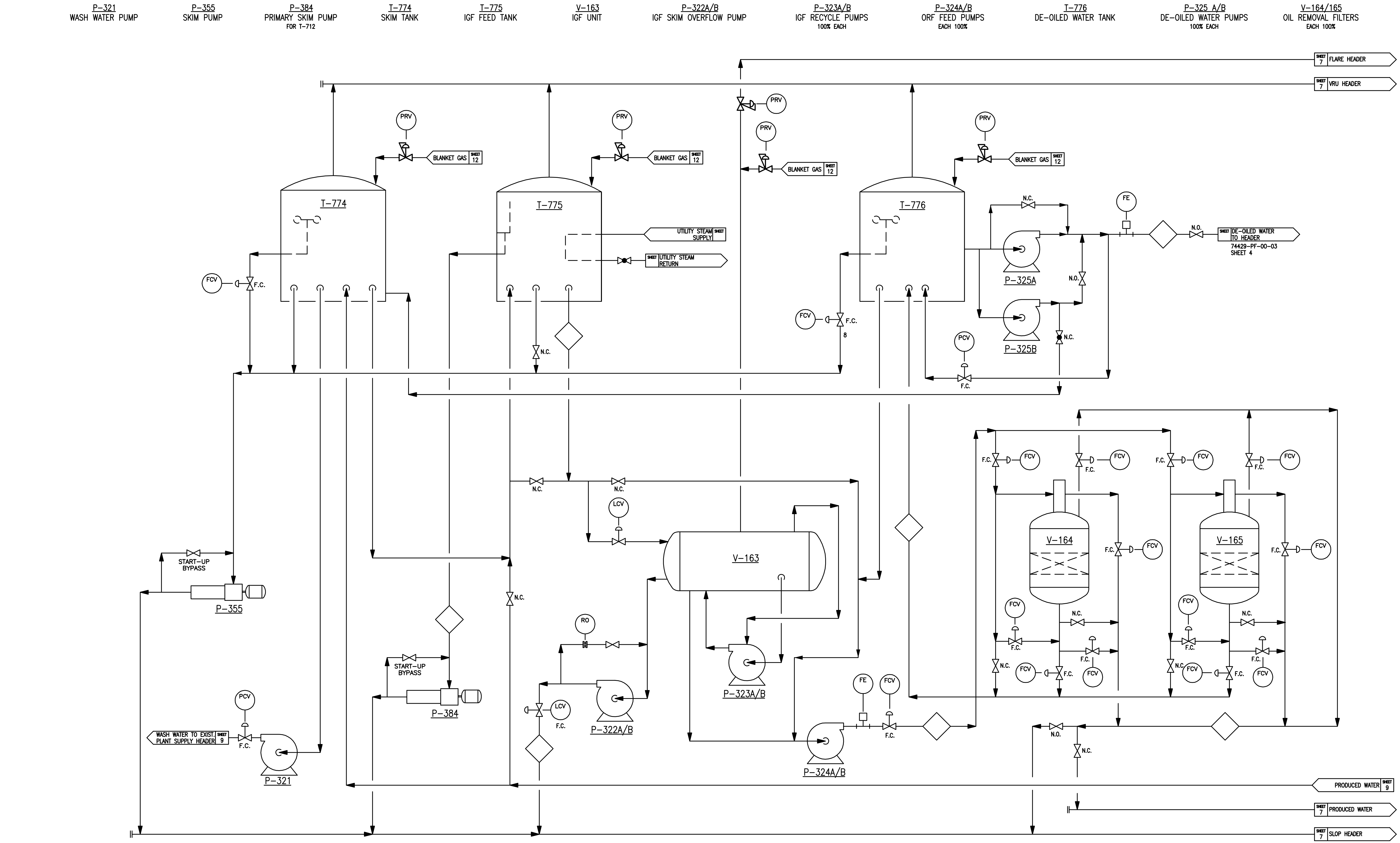
SHEET NUMBER:
4 of 13
FIGURE:
B.5.0-2



Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

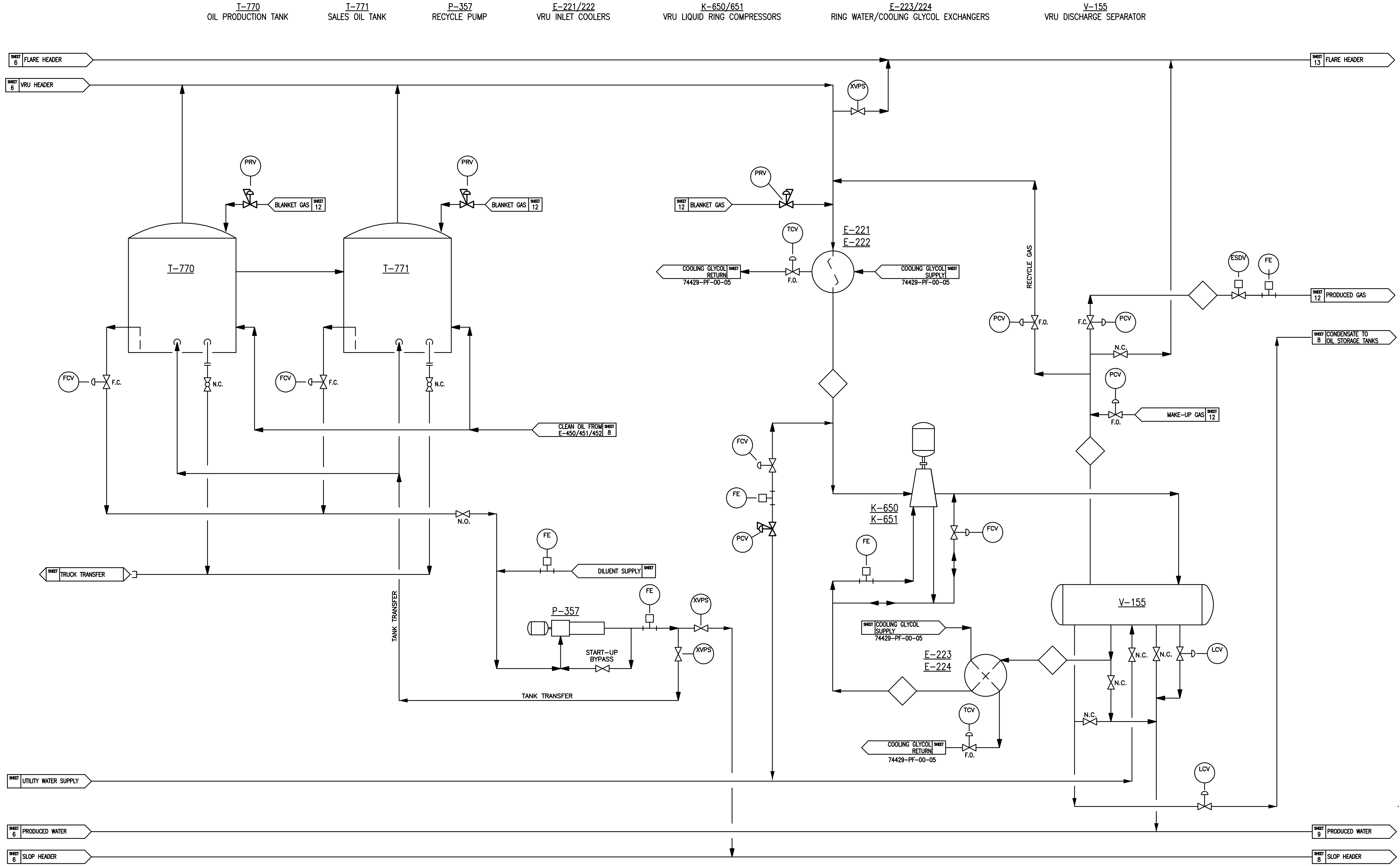
SHEET NUMBER: 5 of 13

FIGURE: B.5.0-2



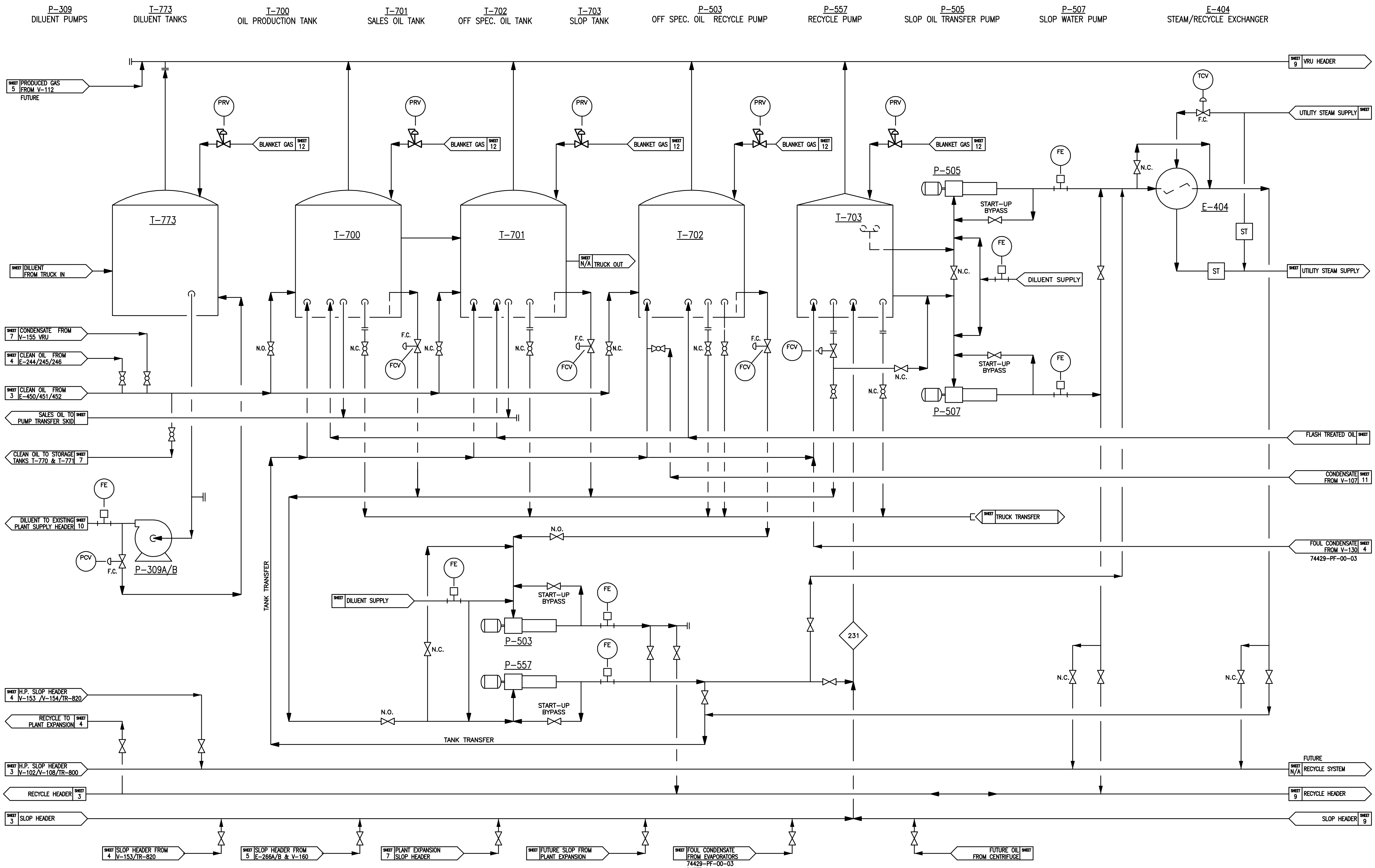
Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER:
6 of 13
FIGURE:
B.5.0-2



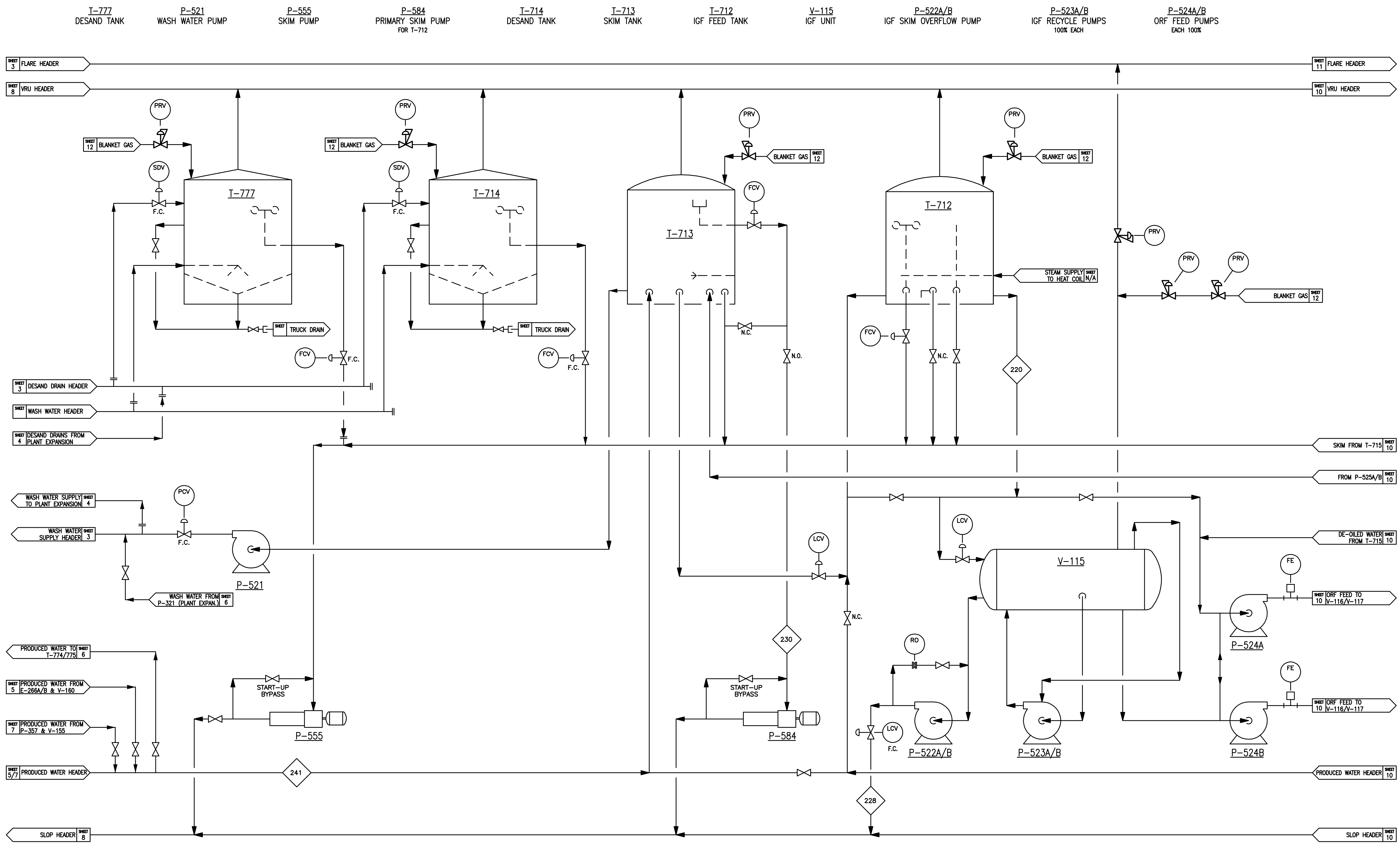
Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER:
7 of 13
FIGURE:
B.5.0-2



Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

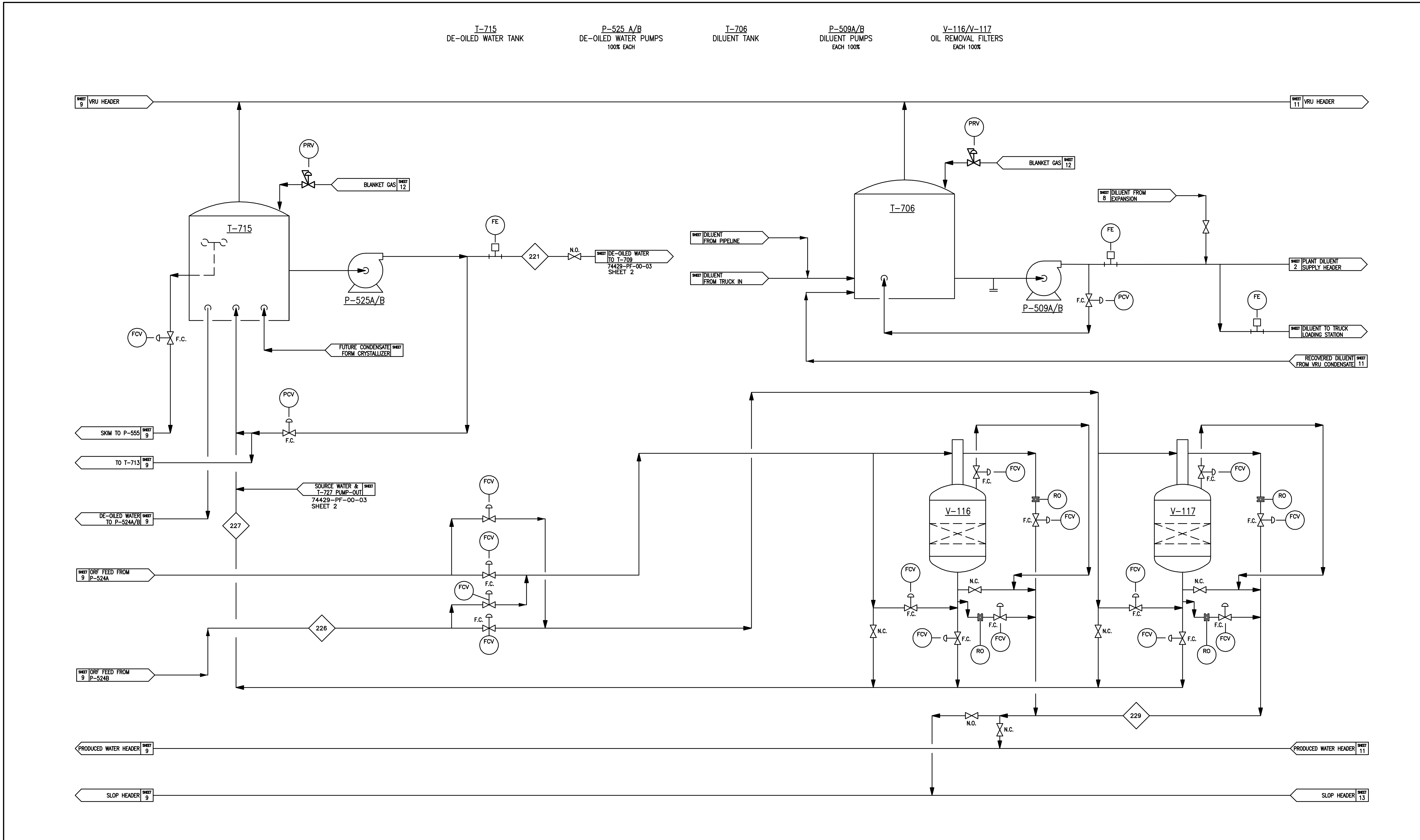
SHEET NUMBER:
8 of 13
FIGURE:
B.5.0-2



Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER: 9 of 13

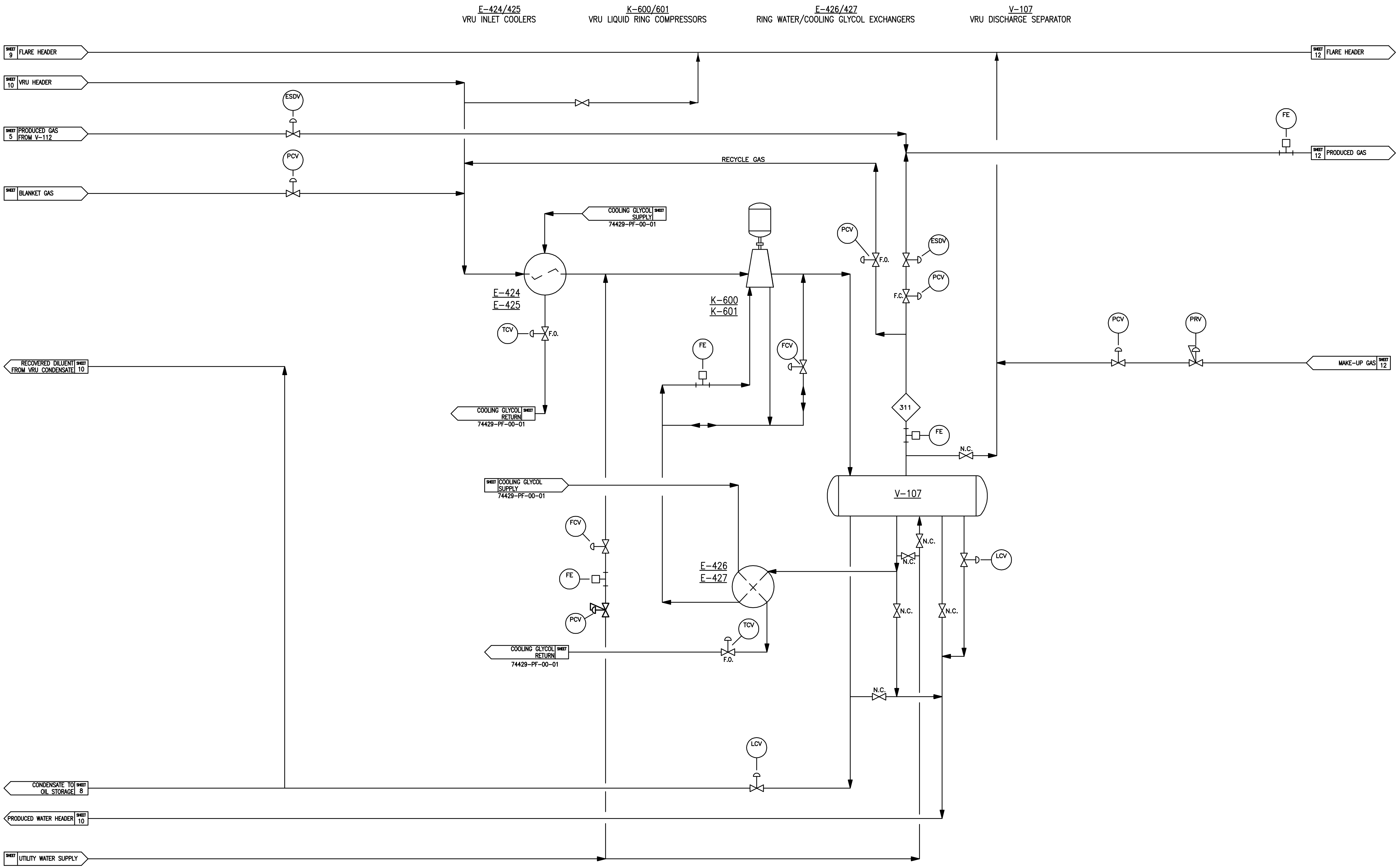
FIGURE: B.5.0-2



Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER: 10 of 13

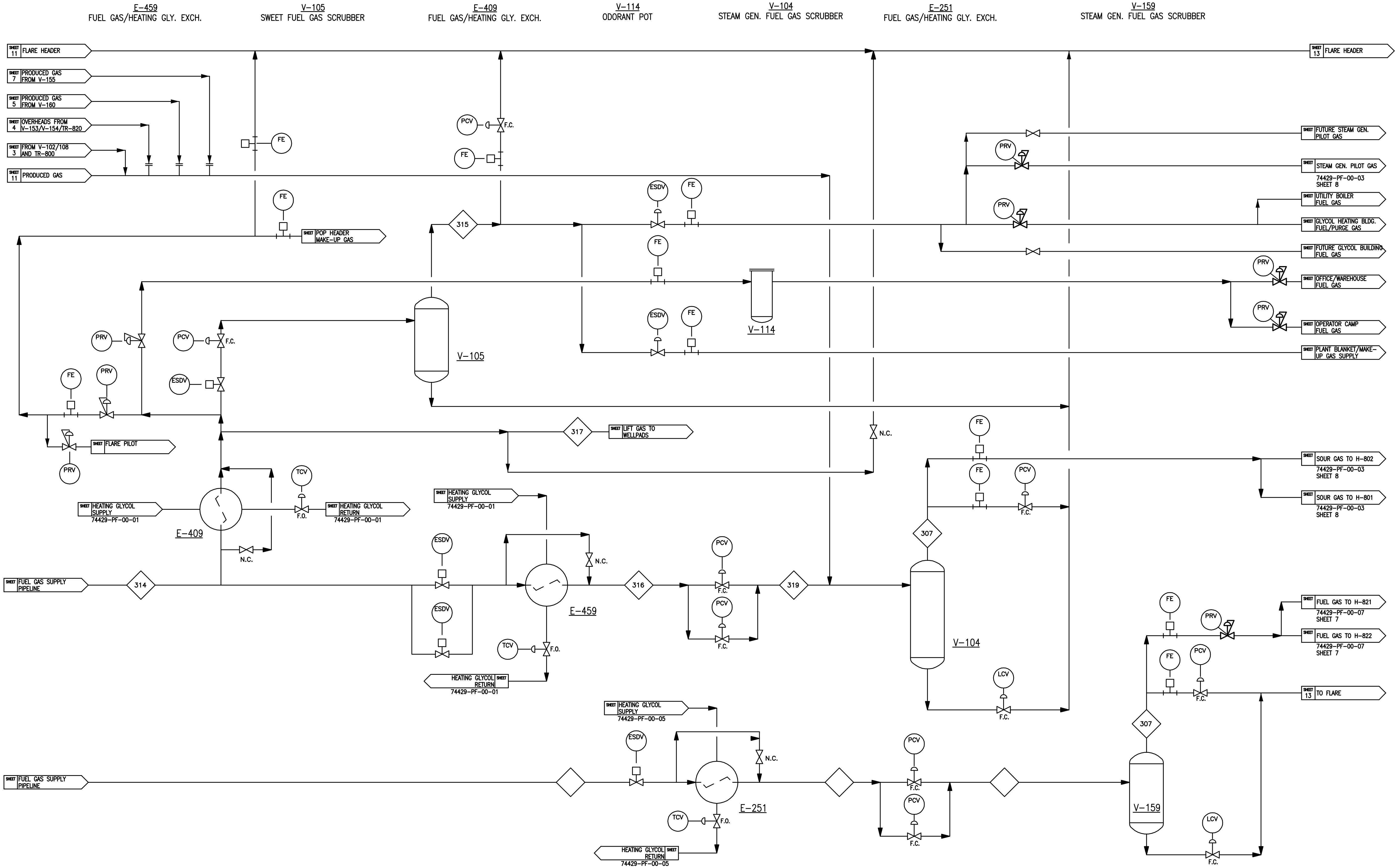
FIGURE: B.5.0-2



Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER: 11 of 13

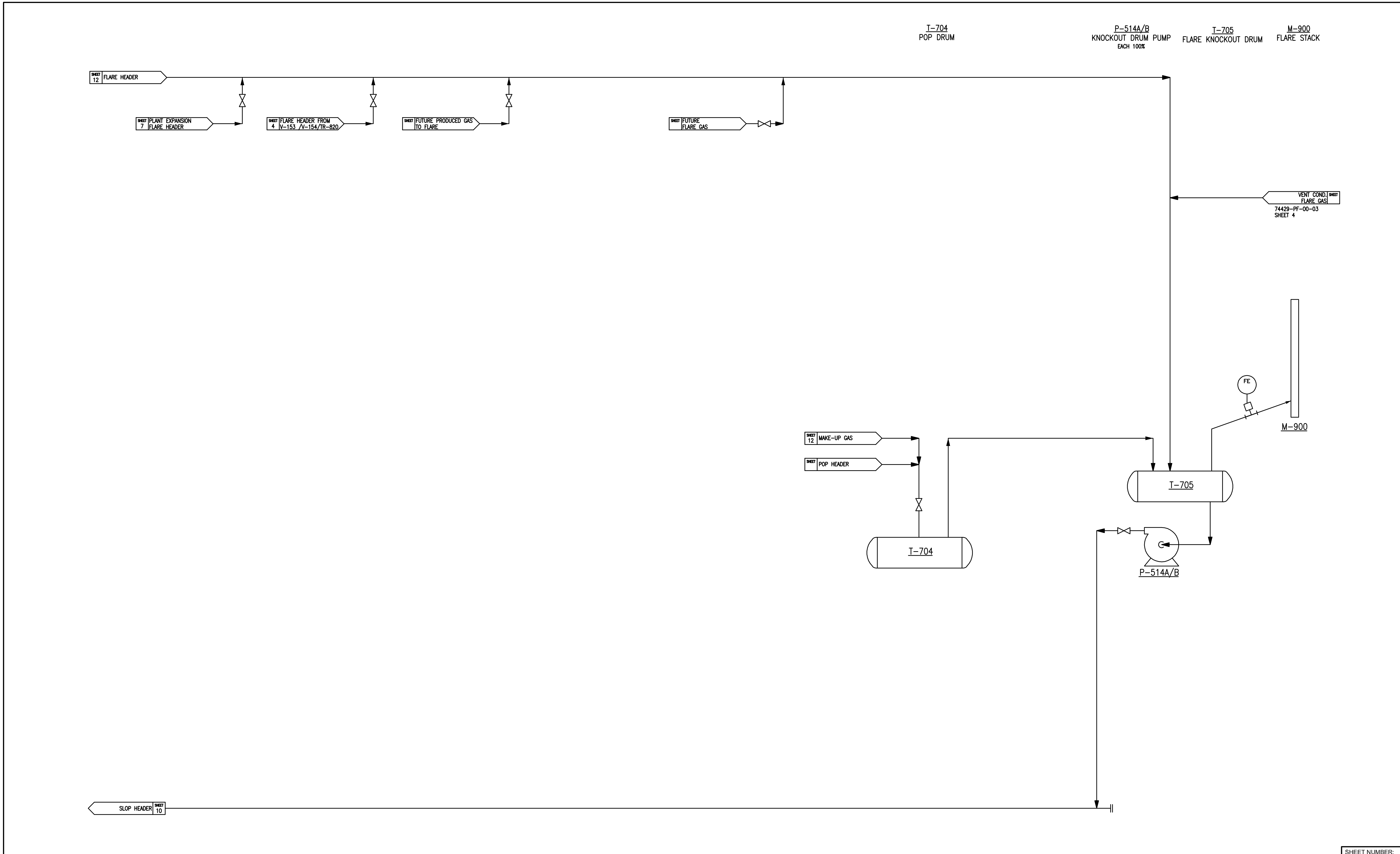
FIGURE: B.5.0-2



Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER:
12 of 13

FIGURE:
B.5.0-2

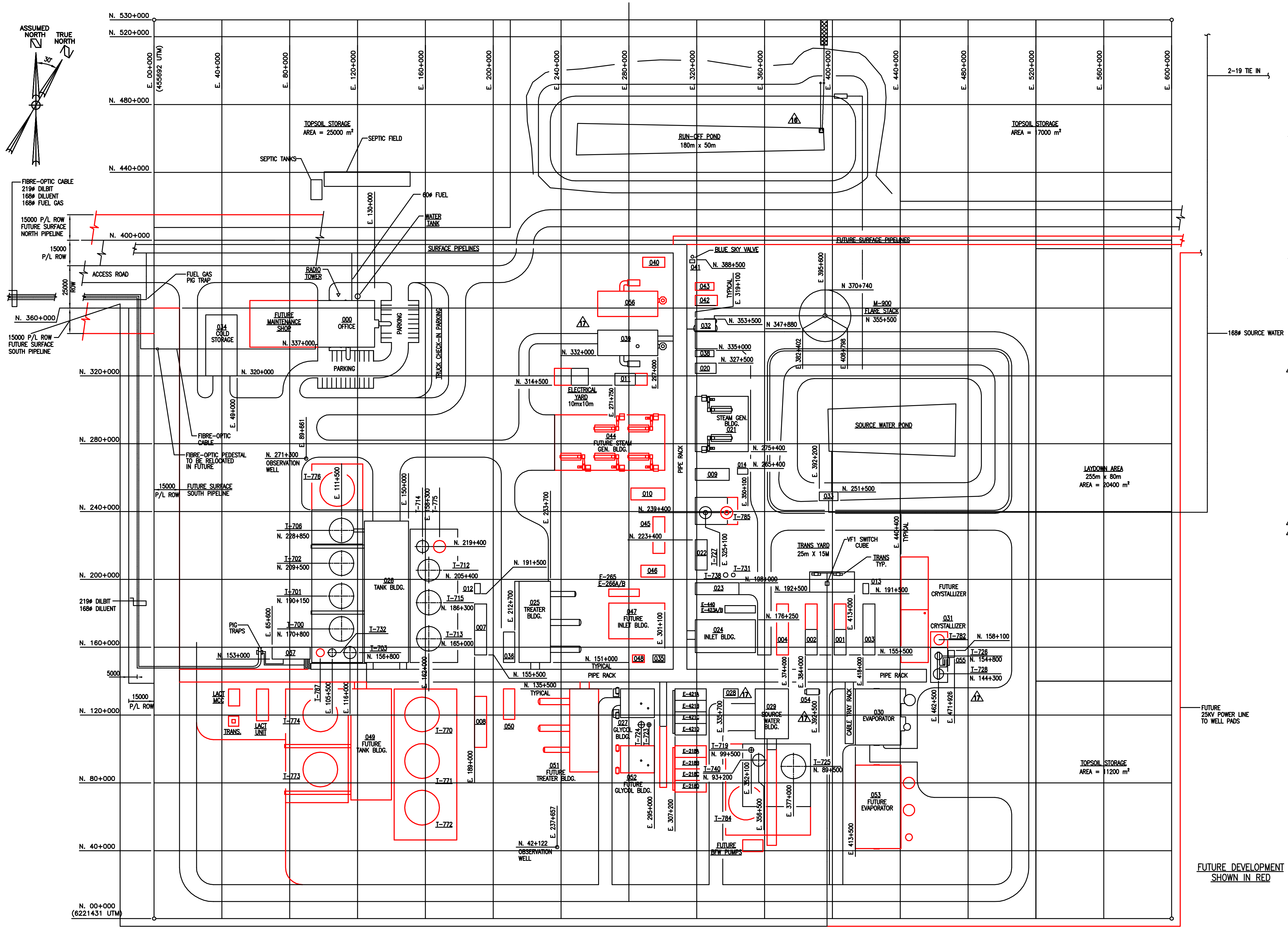


Source: BDR Engineering Ltd., 74429-PF-00-06.dwg, Rev. 1.

SHEET NUMBER:
13 of 13

FIGURE:
B.5.0-2

Main Menu | Search | Main TOC



EQUIPMENT LEGEND				
TAG	EQUIPMENT DESCRIPTION	WIDTH	LENGTH	HEIGHT
000	OFFICE/WAREHOUSE	27432	33528	7620
001	ELECTRICAL BUILDING SWGR-100	7000	15000	4216
002	ELECTRICAL BUILDING SWGR-101	7000	15000	4216
003	ELECTRICAL BUILDING MCC-110	7000	30000	4216
004	FUTURE ELECT. BUILDING MCC-120	7000	30000	4216
007	ELECTRICAL BUILDING MCC-210	7000	30000	4216
008	FUTURE ELECT. BUILDING MCC-220	7000	30000	4216
009	ELECTRICAL BUILDING MCC-310	7000	20000	4216
010	FUTURE ELECT. BUILDING MCC-320	7000	20000	4216
011	CO-GEN MCC	7000	12000	4216
012	EMERGENCY GENERATOR G-200	3352	6096	2738
013	EMERGENCY GENERATOR G-100	3352	6096	2738
014	EMERGENCY GENERATOR G-300	3352	6096	2738
020	FUEL GAS BUILDING	6000	12300	4495
021	STEAM GENERATOR BUILDING	31200	32600	11240
022	BFW PUMP BUILDING	7000	17900	4724
023	CHEMICAL BUILDING	7000	25700	5182
024	INLET BUILDING	19400	31000	6839
025	TREATER BUILDING	18500	47800	6525
026	TANK BUILDING	26000	83400	8852
027	GLYCOL BUILDING	20000	17000	4437
028	NITROGEN SKID	5334	8712	N/A
029	SOURCE WATER BUILDING	19500	29500	6493
030	EVAPORATOR BUILDING	26900	33200	13835
031	CRYSTALLIZER BUILDING	16026	31099	15544
032	FLARE KNOCKOUT BUILDING	6000	9144	5030
033	SOURCE WATER PUMP HOUSE	5000	11000	3404
034	COLD STORAGE BUILDING	18600	36000	2658
035	INSTR. AIR SKID	4450	7000	3658
036	CLEAN OIL EXCHANGER SKID	6700	18000	N/A
037	DILBIT TRANSFER SKID	7000	22400	4694
038	FUEL GAS EXCHANGER SKID	3700	13000	N/A
039	COGEN. BUILDING	15000	35500	11440
040	FUTURE GROUP SEP. BUILDING	6000	13000	5000
041	STEAM SILENCER BUILDING	3000	1800	3048
042	FUTURE FUEL GAS BUILDING	6000	13000	4495
043	FUTURE FUEL GAS EXCH. SKID	4500	11000	N/A
044	FUTURE STEAM GEN. BUILDING	45000	32600	11240
045	FUTURE H.P. BFW PUMP BUILDING	7000	21500	4724
046	FUTURE CHEMICAL BUILDING	7000	14000	5182
047	FUTURE INLET BUILDING	21000	33000	6839
048	FUTURE INSTR. AIR SKID	4450	7000	3658
049	FUTURE TANK BUILDING	24000	66500	8852
050	FUTURE CLEAN OIL EXCH. SKID	6700	18000	5444
051	FUTURE TREATER BUILDING	17000	49000	6525
052	FUTURE GLYCOL BUILDING	20000	16000	4437
053	FUTURE EVAPORATOR BUILDING	26900	49200	13835
054	CLEAN LAB	3581	7315	2438
055	POD 1 WASTE PUMP BUILDING	3700	4100	2746
056	FUTURE CO-GEN BUILDING	15000	35500	11440
E-421 A/B/C/D	GLYCOL COOLERS	6820	18408	5080
E-440	BFW/VAPOR EXCHANGER	652ø	14021	N/A
E-423A/B	INLET VAPOR COOLER	652ø	14021	N/A
E-265	FUTURE BFW/VAPOR EXCHANGER	652ø	14021	N/A
E-266A/B	FUTURE INLET VAPOR COOLER	652ø	14021	N/A
E-218 A/B/C/D	FUTURE GLYCOL COOLERS	6820	18408	5080
M-900	FLARE STACK	219ø	---	39100
T-700	OIL PRODUCTION TANK	14478ø	N/A	9760
T-701	SALES OIL TANK	14478ø	N/A	9760
T-702	OFF SPEC. BITUMEN TANK	14478ø	N/A	9760
T-703	SLOP TANK	7163ø	N/A	9760
T-706	DILUENT TANK	14478ø	N/A	9760
T-712	IGF FEED TANK	12954ø	N/A	9760
T-713	SKIM TANK	14478ø	N/A	9760
T-714	DESAND TANK	7163ø	N/A	9760
T-715	DE-OILED WATER TANK	14478ø	N/A	9760
T-719	BRINE DISSOLVING TANK	2438ø	N/A	4572
T-723	GLYCOL POP TANK	2388ø		1829
T-724	GLYCOL STORAGE TANK	3765ø	N/A	3048
T-725	BOILER FEEDWATER TANK	14478ø	N/A	9760
T-726	POD 1 WASTE TANK	4267ø	N/A	7620
T-727	STEAM GEN. BLOWDOWN TANK	7163ø	N/A	7944
T-728	EVAP. WASTE/CRYST. FEED TANK	6096ø	N/A	8224
T-731	COORDINATED PHOSPHATE TANK	2286ø	N/A	4826
T-732	FLOOR DRAIN TANK	4724ø	N/A	4877
T-738	WATER CLARIFIER BREAKER TANK	2743ø	N/A	4064
T-740	SOURCE WATER TANK	7163ø	N/A	9760
T-770	FUTURE SKIM TANK	20438ø	N/A	9760
T-771	FUTURE IGF FEED TANK	20438ø	N/A	9760
T-772	FUTURE DE-OILED WATER TANK	20438ø	N/A	9760
T-773	FUTURE OIL PRODUCTION TANK	20438ø	N/A	9760
T-774	FUTURE SALES OIL TANK	20438ø	N/A	9760
T-775	FUTURE DESAND TANK	7163ø	N/A	9760
T-776	FUTURE DILUENT TANK	20438ø	N/A	9760
T-782	FUTURE CRYSTALLIZER FEED TANK	7163ø	N/A	7620
T-784	FUTURE BOILER FEEDWATER TANK	20438ø	N/A	9760
T-785	FUTURE BLOWDOWN TANK	7163ø	N/A	7944
T-787	FUTURE FLOOR DRAIN TANK	4724ø	N/A	4877

GENERAL NOTES:

1. "POST CONSTRUCTION DRAWINGS" ARE GENERATED FROM CONSTRUCTION CHANGE INFORMATION FORWARDED TO AMEC BDR LIMITED BY THE OWNER'S FIELD SUPERVISORS AND OR HIRED CONTRACTORS. ANY CHANGES NOT DOCUMENTED WILL NOT APPEAR ON THE DRAWINGS AND THEREFORE THE DRAWING MAY NOT BE AN ACCURATE REPRESENTATION OF THE CONSTRUCTED FACILITY.
2. PRIOR TO THE COMMENCEMENT OF ANY CONSTRUCTION AND OR EXCAVATION IT SHALL BE THE RESPONSIBILITY OF THE OWNERS REPRESENTATIVE TO VERIFY THE LOCATION AND STATUS OF ANY PIPING, ELECTRICAL, EQUIPMENT OR BUILDINGS.
3. ANY REVISIONS MADE TO EXISTING EQUIPMENT, PIPING OR ELECTRICAL ON A FACILITY NOT DESIGNED BY AMEC BDR LIMITED IS ONLY SHOWN AS A REPRESENTATION OF WHAT EXISTS AND MUST BE VERIFIED BY THE OWNER.

0 25 50 100m

Scale 1 : 2 500

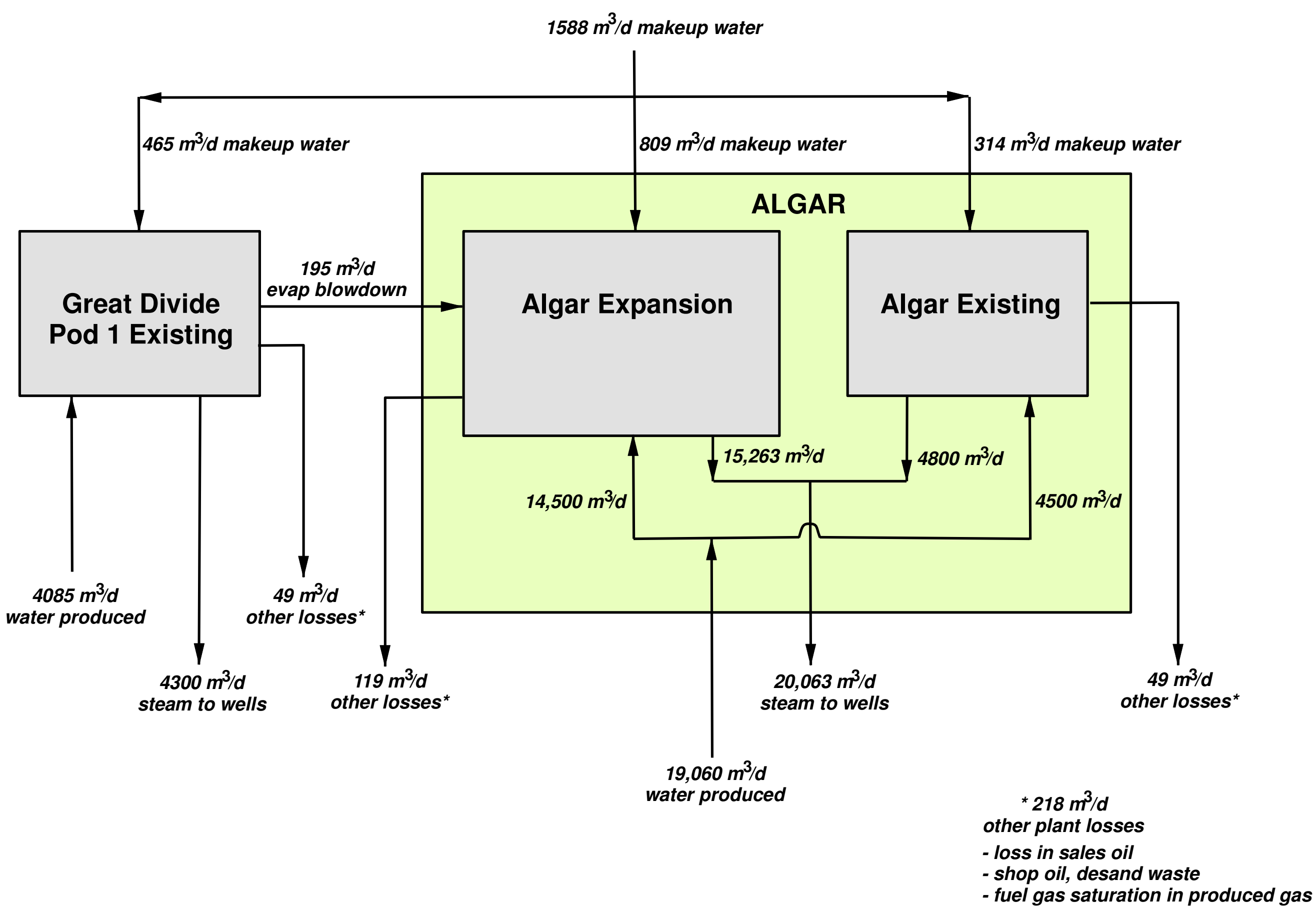
Source: AMEC BDR Limited, PLOT PLAN_REV17_10FEB10.dwg.

PROJECT:
Great Divide SAGD Expansion Project

Plot Plan for Central Processing Facility

Connacher
OIL AND GAS LIMITED

FILE: ...Final Docs\Fig B.5.1-1 Plot Plan.dwg
DRAWN: Others
CHECKED: DM
DATE: May 4/10
PROJECT: 07-104
FIGURE: **B.5.1-1**



PROJECT: **Great Divide SAGD Expansion Project**		Connacher OIL AND GAS LIMITED
TITLE: **Water Balance**	DRAWN: PS CHECKED: DM DATE: Apr 20/10 PROJECT: 07-104	FIGURE: **B.6.1-1**