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13   **APPENDIX B:**
14
15   **TAR SANDS DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW**
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1   **APPENDIX B:**
2
3   **TAR SANDS DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW**
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5
6   This appendix describes the geology of the tar sands resource area, the resource, the
7   history of tar sands development in the western United States, and provides an overview of the
8   technologies that have been applied to tar sands development. It introduces technologies that
9   may be employed in future developments on U.S. Department of the Interior, Bureau of Land
10   Management (BLM)-administered lands. The technologies that are addressed include those used
11   for recovery (i.e., mining), processing (i.e., separation and pyrolysis of the hydrocarbon fraction),
12   and upgrading of tar sands resources. Finally, Attachment B1 provides an analysis of how the
13   refining industry may adjust to the availability of syncrude feedstocks derived from U.S. tar
14   sands.
15
16   Tar sands deposits occur throughout the world except in Australia and Antarctica
17   (Han and Chang 1994). The largest deposits occur in Alberta, Canada (the Athabasca, Wabasha,
18   Cold Lake, and Peace River areas), and in Venezuela. Smaller deposits occur in the
19   United States, with the larger individual deposits in Utah, California, New Mexico, and
20   Kentucky.
21
22   Accurate estimates of the reserves of hydrocarbon liquids in tar sands deposits have not
23   been made, but worldwide demonstrated deposits (excluding inferred deposits) may total about
24   320×10^9 m^3 ($2,000 \times 10^9$ bbl), with the largest share in Alberta, Canada, at about 270×10^9 m^3
25   ($1,700 \times 10^9$ bbl). There are about 546 occurrences of tar sands in 22 states in the United States
26   in deposits that may have more than 4.5×10^9 m^3 (28×10^9 bbl) of hydrocarbons. About 60% of
27   this potential resource is located in Utah (Spencer et al. 1969; Meyer 1995).
28
29   The term tar sands, also known as oil sands (in Canada), or bituminous sands, commonly
30   describes sandstones or friable sand (quartz) impregnated with a viscous, extra-heavy crude oil
31   known as bitumen (a hydrocarbon soluble in carbon disulfide). Significant amounts of fine
32   material, usually largely or completely clay, are also present. The degree of porosity varies from
33   deposit to deposit and is an important characteristic in terms of recovery processes. The bitumen
34   makes up the desirable fraction of the tar sands from which liquid fuels can be derived. However,
35   the bitumen is usually not recoverable by conventional petroleum production techniques
36   (Oblad et al. 1987; Meyer 1995; Speight 1997).
37
38   The properties and composition of the tar sands and the bitumen significantly influence
39   the selection of recovery and treatment processes and vary among deposits. In the so-called "wet
40   sands" or "water-wet sands" of the Athabasca deposit, a layer of water surrounds the sand grain,
41   and the bitumen partially fills the voids between the wet grains. Utah tar sands lack the water
42   layer; the bitumen is directly in contact with the sand grains without any intervening water
43   (Speight 1997); such tar sands are sometimes referred to as "oil-wet sands." Typically, more than
44   99% of mineral matter is composed of quartz and clays. The general composition of typical
45   deposits at the P.R. Spring Special Tar Sand Area (STSA) showed a porosity of 8.4 vol% with
46   the solid/liquid fraction being 90.5% sand, 1.5% fines, 7.5% bitumen, and 0.5% water by weight

1   (Grosse and McGowan 1984). Utah deposits range from largely consolidated sands with low
2   porosity and permeability to, in some cases, unconsolidated sands (Speight 1997). High
3   concentrations of heteroatoms tend to increase viscosity, increase the bonding of bitumen with
4   minerals, reduce yields, and make processing more difficult (Oblad et al. 1987).
5
6   To utilize a tar sands resource in a mining operation, the bitumen must be recovered from
7   its natural setting, extracted from the inorganic matrix (largely sand and silt) in which it occurs,
8   and upgraded to produce a synthetic crude oil suitable as a feedstock for a conventional refinery.
9   In general, it takes about 2.0 tonnes (2.2 tons) of surface-mined Athabasca tar sands to produce
10   159 L or 1 barrel (42 gal) of synthetic oil (Oil Sands Discovery Center 2006a). Nonmining
11   operations recover the bitumen already free of the matrix (sand and clays) in which it originally
12   occurred. Preparation may require removal of bitumen or vaporized bitumen from steam, other
13   gases, water, or solvents. Depending on the end product required, upgrading may not be
14   required.
15
16   At this time, there are no commercial tar sands operations on public lands in Utah.
17   Commercial development could occur on lands with existing combined hydrocarbon leases
18   (CHLs). The BLM does predict some commercial development on public lands under the new tar
19   sands leasing program that would be established with this *Allocation of Oil Shale and Tar Sands*
20   *Resources on Lands Administered by the Bureau of Land Management in Colorado, Utah, and*
21   *Wyoming Draft Programmatic Environmental Impact Statement (PEIS) and Possible Land Use*
22   *Plan Amendments* and the accompanying Record of Decision (ROD). It is also likely that
23   additional development would proceed on private and/or state lands. The impacts being
24   evaluated in the PEIS could occur under either a CHL or under a tar sands lease; however, the
25   decisions that may result from this PEIS and its accompanying ROD are not applicable to CHLs.
26
27   The following discussion includes general information on the geology, development
28   history, and technologies for tar sands development that are being considered in this PEIS.
29   Chapter 9 of the PEIS provides a glossary of technical terms used in the PEIS and its appendices,
30   including geologic terms.
31
32
33   **B.1 DESCRIPTION OF GEOLOGY**
34
35   Tar sands are sedimentary rocks containing bitumen, a heavy hydrocarbon compound.
36   Tar sands deposits may be divided into two major types. The first type is a breached petroleum
37   reservoir where erosion has removed the capping layers from a reservoir of relatively heavy
38   petroleum, allowing the more volatile petroleum hydrocarbons to escape. The second type of tar
39   sands deposit forms when liquid petroleum seeps into a near-surface reservoir from which the
40   more volatile petroleum hydrocarbons escape. In either type of deposit, the lighter, more volatile
41   hydrocarbons have escaped to the environment, leaving the heavier, less volatile hydrocarbons in
42   place. The material left in place is altered by contact with air, bacteria, and groundwater.
43   Because of the very viscous nature of the bitumen in tar sands, tar sands cannot be processed by
44   normal petroleum production techniques.
45

1   Tar sands deposits are not uniform. Differences in the permeability and porosity of the
2   reservoir rock and varying degrees of alteration by contact with air, bacteria, and groundwater
3   mean that there is a large degree of uncertainty in the estimates of the bitumen content of a given
4   tar sands deposit. Estimates may be off by an order of magnitude (a factor of 10)
5   (USGS 1980a–k).
6
7   More than 50 tar sands deposits occur in Utah. Limited data are available on many of
8   these deposits, and the sizes of the deposits are based on estimates. Most of the known bitumen
9   occurs in just a few deposits. The deposits that are being evaluated in this PEIS are those
10   deposits classified in the 11 sets of geologic reports (minutes) prepared by the U.S. Geological
11   Survey (USGS) in 1980 (USGS 1980a–k) and formalized by Congress in the Combined
12   Hydrocarbon Leasing Act of 1981 (Public Law [P.L]. 97-78).[1] While there are 11 sets of
13   minutes, in some cases, the geologic report refers to more than one deposit. For example, the
14   minutes titled *Asphalt Ridge–Whiterocks and Vicinity* discuss the Asphalt Ridge deposit, the
15   Whiterocks deposit, the Asphalt Ridge Northwest deposit, the Littlewater Hills deposit, and the
16   Spring Hollow deposit. All of these deposits are included in the designated STSA and in this
17   analysis for the PEIS. For the sake of convenience, the deposits are often combined and referred
18   to on maps, and otherwise, as the Asphalt Ridge STSA.
19
20   Tar sands deposits outside the areas designated by the Secretary of the Interior in the
21   11 sets of minutes are not available for leasing under the tar sands program, but would be
22   available for development under a conventional oil and gas lease. Figure B-1 shows the locations
23   of the STSAs in Utah, as defined by the 11 sets of minutes from the USGS. Figure B-2 shows the
24   generalized stratigraphy of the areas in Utah where the STSAs are present.
25
26   Table B-1 provides estimates of the heavy oil resources for the 11 STSAs as published by
27   Ritzma (1979). Additional resource estimates have been published in an Interstate Oil Compact
28   Commission report titled, *Major Tar Sand and Heavy Oil Deposits of the United States*
29   (Lewin and Associates 1983). The data indicate that a large percentage of the tar sands bitumen
30   in Utah is located within just a few of the STSAs. The following sections summarize the
31   information that is available for each of the STSAs. The level of detail varies between the STSAs
32   because significant amounts of information have been compiled only for those STSAs with the
33   largest resource base.
34
35
36   **B.1.1 Argyle Canyon−Willow Creek STSA**
37
38   The Argyle Canyon–Willow Creek STSA, hereafter referred to as the Argyle Canyon
39   STSA, is located in the southwestern portion of the Uinta Basin and includes deposits in two
40   areas. These deposits are sometimes referred to independently as the Argyle Canyon deposits,
41   which are located in the Bad Land Cliffs area, and the Willow Creek deposits, which are located
42   along the western end of the Roan Cliffs. For the purposes of this PEIS, the Argyle Canyon
43

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[1]   The boundaries of the designated STSAs were determined by the Secretary of the Interior's orders of
      November 20, 1980 (Volume 45, pages 76800–76801 of the *Federal Register* [45 FR 76800–76801]) and
      January 21, 1981 (46 FR 6077–6078).

FIGURE B-1 Special Tar Sand Areas in Utah
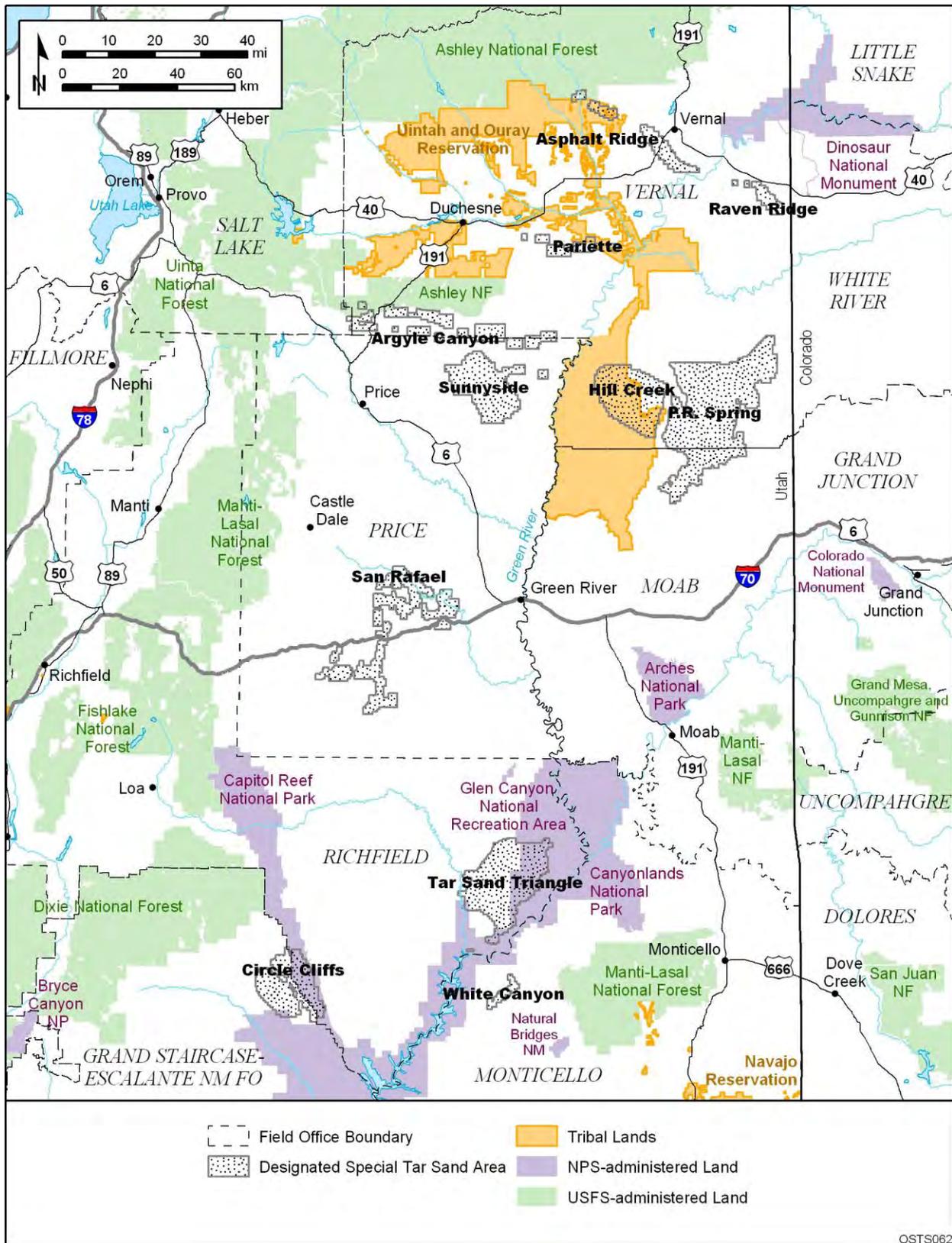
1 STSA includes both areas. All information presented in this
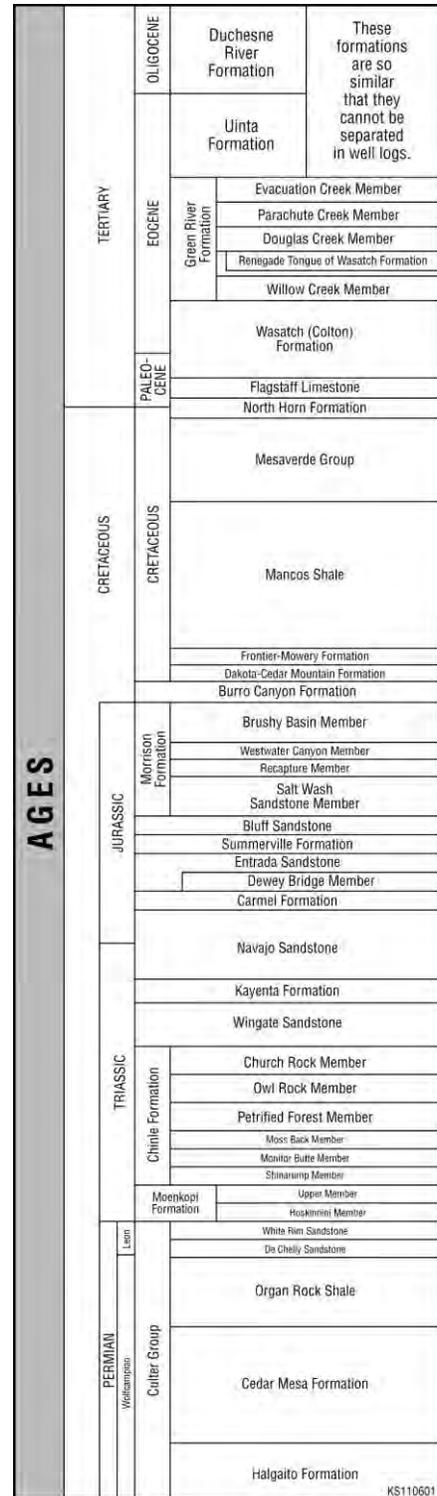2 section is from Blackett (1996) unless otherwise noted.
3
4   The Argyle Canyon portion of the STSA is highly
5 dissected by a north-south trellis-type drainage. The rocks
6 present in this deposit are the Parachute Creek Member and
7 the Deltaic facies of the Eocene Green River Formation,
8 which is overlain by the Eocene Uinta Formation. The
9 Parachute Creek Member is regularly bedded and contains
10 siltstone, mudstone, and oil shale. The Deltaic facies is
11 irregularly bedded, lenticular micaceous sandstone and
12 interbedded mudstone.
13
14   The Willow Creek portion of the area is
15 characterized by high plateaus dissected by deep,
16 steep-walled canyons. Rocks present in the Willow Creek
17 deposit are the upper part of the Garden Gulch Member and
18 the lower part of the Parachute Creek Member of the Green
19 River Formation (Eocene). The Garden Gulch Member
20 consists of interbedded thin sandstone, siltstone, shale, and
21 limestone. The Parachute Creek Member is composed of
22 massive beds, thinning upward, of fine-grained sandstone,
23 interbedded with siltstone and shale.
24
25   Within the Argyle Canyon deposit, most of the
26 bitumen is contained in the sandstones of the Deltaic facies.
27 Within the Willow Creek deposit, channel sandstones
28 contain most of the bitumen. Recovery of the bitumen in
29 areas near outcrops, with gentle dips, would be amenable to
30 surface mining. The remainder of the area would have to be
31 developed by in situ methods (BLM 1984).
32
33
34 **B.1.2 Asphalt Ridge–Whiterocks and Vicinity STSA**
35
36   The Asphalt Ridge–Whiterocks and Vicinity STSA,
37 hereafter referred to as the Asphalt Ridge STSA, is located
38 along Asphalt Ridge, on the north-northeast flank of the
39 Uinta Basin. Asphalt Ridge is a northwest-southeast
40 trending cuesta, with dips to the southwest. All information
41 presented in this section is from Blackett (1996) unless
42 otherwise noted.
43
44

**FIGURE B-2 Generalized
Stratigraphy of the Areas in Utah
Where the STSAs Are Present**

1
2

TABLE B-1 Estimated Resources in Place in Utah Tar Sands Deposits

	Measured (million bbl)[a]	Speculative (million bbl)
Major Deposits		
Uintah Basin		
P.R. Spring	2,140	2,230
Hill Creek	320	560
Sunnyside	4,400	1,700
Whiterocks	60	60
Asphalt Ridge	830	310
Paradox Basin		
Tar Sand Triangle	2,500	420
Nequoia Arch	730	160
Circle Cliffs Uplift		
Circle Cliffs	590	1,140
San Rafael Uplift		
San Rafael Swell	300	250
Subtotal	11,870	6,830
Minor Deposits		
Uinta Basin		
Argyle Canyon	–[b]	50–75
Raven Ridge	–	75–100
Rimrock	–	25–30
Cottonwood–Jacks Canyon	–	20–25
Littlewater Hills	–	10–12
Minnie Maud Creek	–	10–15
Pariette	–	12–15
Willow Creek	–	10–15
San Rafael Uplift		
Black Dragon	–	100–125
Chute Canyon	–	50–60
Cottonwood Draw	–	75–80
Red Canyon	–	60–80
Wickiup	–	60–75
Subtotal		557–707
Total	11,870	7,387–7,537

[a] bbl = barrel; 1 bbl syncrude = 42 gal.

[b] A dash indicates no formal quantification available.

Source: Ritzma (1979).

3
4

1   The rock units present at Asphalt Ridge, in order of decreasing age, are the Mesaverde
2 Group (Asphalt Ridge Sandstone, Mancos Shale, and Rim Rock Sandstone; all Cretaceous),
3 possibly the Uinta Formation (Eocene), and the Duchesne River Formation (Eocene-Oligocene).
4 The Uinta Formation may or may not be present as the contact between the Mesaverde Group
5 and the Duchesne River Formation; it is gradational and difficult to recognize. The Duchesne
6 River Formation unconformably overlies the Rim Rock Sandstone. Both the Duchesne River
7 Formation and the Rim Rock Sandstone dip to the south-southwest at gradients ranging from
8 8° to 30°; the Rim Rock Sandstone generally has the steeper dips.
9
10   The White Rocks tar sands deposit is found in the Navajo sandstone, which dips from
11 70° to near vertical due to a major regional uplift and folding. Severe faulting has caused a large
12 offset of the Navajo and other formations in the subsurface. However, within the limits of the
13 deposit as seen at the surface, local faulting is small. The over- and underlying strata are
14 impervious shales of the adjacent Chinle and Carmel Formations, which have sealed the bitumen
15 in the Navajo.
16
17   Several faults are known to have cut across the trend of the ridge. One has 150 ft of
18 vertical displacement. At least one fault acted as a barrier to hydrocarbon migration, as the
19 Asphalt Ridge Sandstone is bitumen saturated to the northwest of the fault and unsaturated to the
20 southeast.
21
22   The Rim Rock Sandstone, the Uinta Formation (where present), and the Duchesne River
23 Formation all contain bitumen in the Asphalt Ridge area. The Rim Rock Sandstone is generally
24 bitumen saturated for its entire outcrop length in the Asphalt Ridge area. The Uinta Formation
25 generally contains bitumen only in sandy beds near the southern part of Asphalt Ridge. The
26 bitumen saturation of the Duchesne River Formation varies both laterally and vertically. Rock
27 composition of the Duchesne River Formation ranges from shale to conglomerate. The rocks
28 with the greatest porosity, coarse sandstones, tend to have the highest bitumen saturations.
29
30   It has been suggested that the bitumen in the White Rocks deposit is Tertiary and has
31 migrated across joints and unconformities to the Jurassic Navajo. However, original paths of
32 migration are not clear and Paleozoic source rocks have been suggested as an alternate
33 hypothesis for the source of hydrocarbons. In the subsurface, the bitumen extends down to the
34 water/oil contact in the steeply dipping Navajo sandstone.
35
36   Recovery of the bitumen at this STSA would be amenable to surface mining along the
37 outcrop on Asphalt Ridge. However, the surface minable portion of the deposit is primarily on
38 state and private lands. In the remainder of the area, the deposits would have to be recovered by
39 in situ methods (BLM 1984).
40
41
42 **B.1.3 Circle Cliffs East and West Flanks STSA**
43
44   The Circle Cliffs East and West Flanks STSA, hereafter referred to as the Circle Cliffs
45 STSA, is located in south-central Utah, along the Circle Cliffs anticline. All information
46 presented in this section is from BLM (1984) unless otherwise noted.
47

1   Rocks exposed at the surface in the vicinity of the Circle Cliffs anticline, in decreasing
2 age order, are the Kaibab Limestone (Permian), Moenkopi Formation (Torrey Member and
3 Moody Creek Member; Triassic), Chinle Formation (including the Shinarump Conglomerate;
4 Triassic), Wingate Sandstone (Triassic/Jurassic), Kayenta Formation (Jurassic), Navajo
5 Sandstone (Jurassic), Carmel Formation (Jurassic), Entrada Sandstone (Jurassic), and several
6 younger units (Short 2006). The beds on the eastern side of the anticline dip from a few degrees
7 to more than 25°. The beds on the western side of the anticline dip from 2° to 3° to the west.
8
9   The bitumen is contained in shoreface and fluvial-deltaic sandstones of the Torrey and
10 Moody Creek Members of the Moenkopi Formation (Schamel and Baza 2003). Recovery of the
11 bitumen would only be amenable to surface mining in very limited areas. In most of the area, the
12 deposits would have to be recovered by in situ methods (BLM 1984; Kohler 2006).
13
14
15 **B.1.4 Hill Creek STSA**
16
17   The Hill Creek STSA is located along the Book Cliffs, on the south flank of the
18 Uinta Basin. It lies to the west of the P.R. Spring STSA and east of the Sunnyside and Vicinity
19 STSA. All information presented in this section is from Blackett (1996) unless otherwise noted.
20
21   The Hill Creek STSA tar sands deposits are contained entirely within the Eocene Green
22 River Formation. The composition of the Green River Formation includes oil shale, marlstone,
23 shale, siltstone, sandstone, limestone, and tuff. The three mappable units of the Green River
24 Formation in the vicinity of the Hill Creek deposit, in order of decreasing age, are the Douglas
25 Creek Member, the Parachute Creek Member, and the Evacuation Creek Member. The
26 Mahogany Bed, an important oil shale resource, lies between the Douglas Creek and Parachute
27 Creek Members.
28
29   There are five bitumen-impregnated zones in the Hill Creek STSA. Four of these zones
30 are in the upper portions of the Douglas Creek Member, and one is in the lower part of the
31 Parachute Creek Member. In ascending order, these zones have been designated A, B, C, D,
32 and E. The zones can be correlated throughout the deposit.
33
34   The extent of bitumen saturation varies laterally and vertically throughout each of the
35 zones. Overburden thicknesses are too great throughout most of the deposit for surface mining to
36 be feasible, and it is likely that recovery of the bitumen would require in situ methods
37 (BLM 1984).
38
39
40 **B.1.5 Pariette STSA**
41
42   The Pariette STSA is located on the southern flank of the Uinta Basin in an area of low
43 relief near the topographic center of the basin. All information presented in this section is from
44 Blackett (1996) unless otherwise noted.
45

1   Rocks of the Uinta Formation (Eocene) are present within the Pariette STSA. The Uinta
2   Formation rocks in the STSA are overlain by Quaternary surficial deposits. The Uinta Formation
3   is nearly flat in the STSA, dipping 1° to 4° to the north.
4
5   The bitumen-saturated zones are typically lenticular, fluvial sandstones. There is a large
6   amount of horizontal and vertical variability in bitumen saturation levels within the Pariette
7   STSA deposits. The small size and discontinuous nature of the individual areas of rock saturated
8   with bitumen would tend to limit in situ production to a few of the larger bitumen-saturated
9   areas. Development is limited by the small size, the lean quality (saturation is low), and the
10 discontinuous lenticular-occurring nature of the deposits (USGS 1980e).
11
12
13 **B.1.6 P.R. Spring STSA**
14
15 The P.R. Spring STSA is located along the Book Cliffs in the southeastern part of the
16 Uinta Basin, to the east of the Hill Creek STSA. The topography in the area is relatively flat,
17 with narrow plateaus and mesas incised by intermittent and perennial streams. All information
18 presented in this section is from Blackett (1996) unless otherwise noted.
19
20 The geology of the Hill Creek STSA and the P.R. Spring STSA is essentially identical.
21 The P.R. Spring STSA tar sands are contained entirely within the Eocene Green River
22 Formation. The composition of the Green River Formation includes oil shale, marlstone, shale,
23 siltstone, sandstone, limestone, and tuff. The three mappable units of the Green River Formation
24 in the vicinity of the P.R. Spring deposit, in order of decreasing age, are the Douglas Creek
25 Member, the Parachute Creek Member, and the Evacuation Creek Member. The Mahogany Bed,
26 an important oil shale resource, lies between the Douglas Creek and the Parachute Creek
27 Members.
28
29 There are five bitumen-impregnated zones in the P.R. Spring STSA. Four of these zones
30 are in the upper portions of the Douglas Creek Member, and one is in the lower part of the
31 Parachute Creek Member. In ascending order, these zones have been designated A, B, C, D,
32 and E. The zones can be correlated throughout the deposit.
33
34 The extent of bitumen saturation varies laterally and vertically throughout each of the
35 zones. Numerous tar seeps occur along the outcrop of the bitumen-impregnated areas within the
36 STSA. They tend to be active during periods of wet weather and inactive during drier periods.
37
38 Overburden thicknesses are too great throughout most of the deposit for surface mining
39 to be feasible, except in the southern part of the STSA. It is likely that recovery of the bitumen
40 would require in situ methods, except in the southern part of the STSA where these deposits are
41 considered among the most valuable for surface mining (USGS 1980f).
42
43

B.1.7 Raven Ridge–Rim Rock and Vicinity STSA

The Raven Ridge–Rim Rock and Vicinity STSA, hereafter referred to as the Raven Ridge STSA, is located on the north flank of the Uinta Basin and includes deposits in two areas. These deposits are sometimes referred to independently as the Raven Ridge deposits, which are located along a series of northwest-trending hogbacks known as Raven Ridge, and the Rim Rock deposits, which lie at the east end of a series of low, west-northwest-trending hogbacks called the Rim Rock. The Raven Ridge portion of the STSA is east of Asphalt Ridge. The Rim Rock portion lies between Raven Ridge and Asphalt Ridge. All information presented in this section is from Blackett (1996) unless otherwise noted.

Rocks present within the Raven Ridge deposit include, in order of decreasing age, the Paleocene/Eocene Green River Formation (Douglas Creek Member, Parachute Creek Member, and Evacuation Creek Member) and the Eocene Uinta Formation. The Mahogany oil shale zone occurs above the Raven Ridge tar sands deposit. Rocks in the Raven Ridge area dip from 10° to 85° southwest, with an average dip of 30°. They are composed of shoreline and deltaic facies sandstone, limestone, and shale in the Green River Formation, and fluvial-deltaic shale, sandstone, and pebble conglomerate in the Uinta Formation. All four of the rock units present in the Raven Ridge area contain some bitumen. Saturation levels vary greatly between units, as well as in lateral and vertical extent.

The Wasatch Formation (Paleocene) and the Douglas Creek and Parachute Creek Members of the Green River Formation are present in the Rim Rock part of the STSA. Rocks in the Rim Rock area dip as much as 76° to the southwest. Each successively younger unit overlaps and truncates the next older unit. Bitumen is located within the Wasatch Formation sandstones and in Green River sandstones that truncate older Wasatch Formation rocks.

Recovery of the bitumen by surface mining would be possible in the Raven Ridge STSA only along the outcrops on Raven Ridge. In situ methods would be needed elsewhere (BLM 1984).

B.1.8 San Rafael Swell STSA

The San Rafael Swell STSA is located in the southwestern portion of Utah. The San Rafael Swell is a breached dome, with the core of older rocks exposed in the middle of the dome. The rocks dip away from the geographic center of the dome, in all directions. Schamel and Baza (2003) report that the White Rim Sandstone, within the San Rafael Swell deposit, contains bitumen. The White Rim Sandstone is present only on the eastern most edge of the San Rafael Swell. All information presented in this section is from BLM (1984) unless otherwise noted.

Rocks exposed at the surface in the vicinity of the San Rafael Swell, in order of decreasing age, are the Cutler Group (White Rim Sandstone; Permian), Kaibab Limestone (Permian), Moenkopi Formation (Sinbad Limestone Member and Black Dragon Member; Triassic), Chinle Formation (Triassic), Wingate Sandstone (Triassic/Jurassic), Kayenta

1 Formation (Jurassic), Navajo Sandstone (Jurassic), and San Rafael Group (Carmel Formation,
2 Entrada Sandstone, Curtis Formation, and Summerville Formation; Jurassic) (USGS 2006).
3
4   All of the rock units in the San Rafael Swell area contain bitumen in some areas
5 (Schamel and Baza 2003). Within the deposit, most of the bitumen occurs within the lower and
6 middle portions of the Black Dragon Member of the Moenkopi Formation. The other units
7 contain lesser amounts of bitumen, with some such as the Sinbad Limestone containing only
8 isolated spots of bitumen.
9
10   In situ methods would be the preferred methods of production for the San Rafael Swell
11 STSA. The overburden is too great for recovery of the bitumen by surface mining (BLM 1984).
12
13
14 **B.1.9 Sunnyside and Vicinity STSA**
15
16   The Sunnyside and Vicinity STSA, hereafter referred to as the Sunnyside STSA, is
17 located along the Roan Cliffs on the southwestern flank of the Uinta Basin. The topography of
18 this area is characterized by high relief and rugged terrain. All information presented in this
19 section is from Blackett (1996) unless otherwise noted.
20
21   The rock units present at Sunnyside, in order of decreasing age, are Colton Formation
22 (Paleocene/Eocene) and the Lower Green River Formation (Eocene). Colton Formation rocks are
23 shale, siltstone, and sandstone, which were deposited in a fluvial-deltaic environment. The Green
24 River rocks were deposited in a lacustrine environment and are composed of shale, marlstone,
25 siltstone, sandstone, limestone, and tuff. Bitumen in the deposit is typically contained in
26 sandstone. The bitumen content is typically inversely proportional to the distance from the
27 deltaic complex.
28
29   The rocks in the Sunnyside area dip to the northeast at 3° to 12°. Small-scale faulting and
30 fracturing occur in the area but do not appear to have affected bitumen emplacement.
31
32   The depositional environments in this area have resulted in a complex stratigraphy.
33 Bitumen saturation may vary greatly within just a few feet, with bitumen-saturated rock and
34 barren rock occurring within a few feet of each other. Surface mapping has identified as many as
35 32 bitumen saturated beds.
36
37   Recovery of the bitumen by both surface mining and in situ methods would be needed to
38 fully develop the Sunnyside deposit (BLM 1984).
39
40
41 **B.1.10 Tar Sand Triangle STSA**
42
43   The Tar Sand Triangle STSA is located in southeastern Utah along the western edge of
44 the Monument Upwarp. The topography of the area is a dissected plateau. The margins of the
45 plateau have stair-step topography, and mesas and buttes occur as outliers from the plateau

1   (BLM 1984). All information presented in this section is from Glassett and Glassett (1976)
2   unless otherwise noted.
3
4   The rocks present in the Tar Sand Triangle STSA, in order of decreasing age, include the
5   Cutler Group (Cedar Mesa Sandstone and White Rim Sandstone; Permian), Moenkopi Formation
6   (Triassic), and Chinle Formation (Shinarump Conglomerate; Triassic). The Monument Upwarp
7   is a westward-dipping monocline, and the Permian and Triassic rocks of central Utah pinch out
8   against the upwarp. The bitumen in the Tar Sand Triangle STSA appears to be the residue of a
9   gigantic oil field located in the stratigraphic trap formed by this pinch out. The oil field was
10 breached by erosion allowing the more volatile components to escape, leaving the less volatile
11 components behind.
12
13   Although bitumen is found in the Cedar Mesa Sandstone, White Rim Sandstone,
14 Moenkopi Formation, and Shinarump Conglomerate, most of the bitumen is located in shoreface
15 and eolian deposits of the Permian White Rim Sandstone near its southeastern extent, as it
16 pinches out against the Monument Upwarp (Schamel and Baza 2003).
17
18   The Tar Sand Triangle deposit may be technically suitable for surface mining; however,
19 the remoteness of the area and other considerations could limit this potential (BLM 1984).
20
21
22 **B.1.11 White Canyon STSA**
23
24   The White Canyon STSA is located south of the Tar Sand Triangle STSA, in the
25 White Canyon area of southeastern Utah. The topography in the area is that of one large mesa
26 with bench and slope topography along its margins. The ground below the mesa is incised by
27 White Canyon. All information presented in this section is from BLM (1984) unless otherwise
28 noted.
29
30   Rocks present in the White Canyon area, in order of decreasing age, include DeChelly
31 and/or White Rim Sandstones (these two sandstones are coeval; Permian), Moenkopi Formation
32 (Hoskinnini Member; Triassic), and Chinle Formation (Shinarup Member; Triassic) (Beer 2005).
33 Other rock units may be present but are not relevant to the tar sands. The Hoskinnini Member,
34 which hosts all of the bitumen in the White Canyon STSA, pinches out toward the northwestern
35 part of the STSA.
36
37   The lack of site-specific data precludes any consideration of mining methods for the
38 White Canyon deposit. The data available on the quality of the deposit suggest that it is not of
39 commercial grade. It may be too heavily jointed for in situ methods, and heavy overburden
40 appears to be unfavorable for surface mining (USGS 1980k).
41
42
43 **B.2 PAST EXPLORATION AND DEVELOPMENT ACTIVITY**
44
45   The mining of petroleum-bearing materials from tar sands has been practiced for
46 thousands of years. Petroleum and bitumen were mined in the Sinai Peninsula before 5,000 B.C.

1   The bitumen was used as an adhesive, brick binder, and waterproofing agent and, somewhat
2   later, it was used to produce petroleum as a fuel. However, the distillation process was lost and
3   not used again until the middle of the nineteenth century with the advent of drilling for oil.
4   Underground oil mining was practiced in the Alsace region of France from about 1735 to 1866.
5   The mined sand was treated on the surface with boiling water to release the oil. After 1866, oil
6   was obtained by letting it drain into mine shafts where it was recovered as a liquid (National
7   Academy of Sciences 1980; Meyer 1995; Speight 1995).
8
9   Natural bitumen (or natural asphalt) has been used throughout the world, primarily in the
10 last 200 years, during which time it was widely used as a paving material. This use has largely
11 been replaced by the use of manufactured asphalt. In the 1890s, the Canadian government
12 became interested in oil sands deposits. Research on recovery mining from the Athabasca oil
13 sands began in the 1920s. Three extensive pilot-scale operations were conducted between 1957
14 and 1967, and commercial operations began in 1967 when the Great Canadian Oil Sands
15 Company (now Suncor) started open-pit mining using bucket-wheel excavators, conveyor belts,
16 and hot water extraction (Oblad et al. 1987; Meyer 1995; Speight 1995, 1997;
17 Woynillowicz et al. 2005). By 1976, cyclic steam recovery had been piloted by Imperial Oil
18 Limited at Cold Lake. Syncrude Canada Ltd. opened the Athabasca deposits in 1978 using
19 draglines, bucket-wheel reclaimers, and conveyor belts. By 1986, steam-assisted gravity drainage
20 (SAGD) had been piloted, and in situ combustion was being researched in Canada. Suncor and
21 Syncrude were in commercial operation as was Imperial Oil's cyclic steam facility. By 1996,
22 both Suncor and Syncrude had converted their extractions to truck and shovel operations. For
23 surface mining, hydrotransport (the transport of mined sand as a slurry of warm water and sand
24 in pipes) rather than conveyor belts was used to transport mined sand to the extraction plant for
25 cold-water extraction, mechanical separation, and by-product recovery. Several new in situ
26 projects were also in commercial operation (Oil Sands Discovery Center 2006a.) By 2004, about
27 two-thirds of the recovered oil sands in Alberta were mined; about one-third was recovered by in
28 situ operations (Alberta Economic Development 2006).
29
30   In Utah, the amount of exploration and development for tar sands resources has varied
31 from location to location. No known exploration or development activities have occurred at the
32 Argyle Canyon, Circle Cliffs, Hill Creek, Pariette, San Rafael Swell, Tar Sand Triangle, or
33 White Canyon STSAs. A brief description of previous activities at the other STSAs is provided
34 below (from Blackett 1996).
35
36   •   *Asphalt Ridge STSA.* The Asphalt Ridge deposit has been the target of many
37   exploration and development efforts. It was mined at least as early as the
38   1920s when the town of Vernal, Utah, paved its streets with material from the
39   deposit. Between 1910 and 1950, a number of shallow wells were drilled in
40   the area in an attempt to locate liquid hydrocarbons below the bitumen cap.
41   During the 1930s, a hot-water extraction plant was built to extract tar from the
42   deposit. Knickerbocker Investment Company and W.M. Barnes Engineering
43   Company conducted a comprehensive evaluation program on Asphalt Ridge
44   in the early 1950s. Sohio Petroleum Company then leased Asphalt Ridge and
45   conducted its own evaluation program. In 1970 or 1971, Major Oil Company
46   obtained a working agreement with Sohio to strip-mine the tar sands and build

1   and operate an extraction plant. Hot water was used to strip the bitumen from
2   the crushed run-of-mine material, and the bitumen was shipped to a refinery in
3   Roosevelt, Utah. Arizona Fuels Corporation and Fairbrim Company acquired
4   the operation in 1972. In the 1970s, Sun Oil Company, Texaco, Phillips
5   Petroleum Company, and Shell Oil Company conducted exploratory drilling
6   at Asphalt Ridge. The U.S. Department of Energy (DOE) conducted extensive
7   field experiments on the deposit between 1971 and 1982.

9   •   *P.R. Spring STSA.* In 1900, John Pope drilled an oil test well in the
10   P.R. Spring deposit. During the early twentieth century (the exact date is
11   unknown), a 50-ft-long adit was driven into a tar sands outcrop in the
12   P.R. Spring area. A steel pipe was run from the adit to a metal trough to
13   collect the gravity-drained oil. In the 1970s and 1980s, the P.R. Spring deposit
14   was the target of intense exploration and research activity by several
15   companies and government agencies. The U-tar Division, Bighorn Oil
16   Company, operated a 100-bbl/day pilot plant in the area. Although several
17   other companies proposed development operations for the P.R. Spring deposit,
18   no viable commercial production has occurred.

20 •   *Raven Ridge STSA.* Sporadic attempts to develop the Raven Ridge deposit
21   were made before 1964. Western Tar Sands, Inc., conducted test mining
22   activities on the deposit during the summer of 1980 and planned to build a
23   100-bbl/day production facility. This plant was not built, and there have been
24   no other exploration or development activities at the STSA since.

26 •   *Sunnyside STSA.* The Sunnyside deposit was mined, primarily for road
27   construction, from 1892 to the late 1940s. The mined material was transported
28   over a 3-mi-long aerial tram and then trucked to the railhead at Sunnyside,
29   where it was shipped to five other western states. A large number of
30   companies, including Shell Oil Company, Signal Oil and Gas Company,
31   Texaco, Gulf Oil Corporation, Pan-American Petroleum Corporation, Phillips
32   Petroleum, Sabine Resources, Cities Service, Amoco, Chevron Resource
33   Company, Great National Corporation, and Mono Power Company,
34   conducted activities in the Sunnyside deposit from 1963 through 1985. Shell
35   Oil Company, Signal Oil and Gas Company, Pan-American Petroleum
36   Corporation, Mono Power Company, and Great National Corporation all
37   conducted pilot operations on the deposit. Sunnyside sandstone was mined as
38   a road-paving material as early as 1892 through 1948. These deposits were
39   also the site of Shell Oil's steam flood pilot plant from 1964 to 1967 and a
40   mining and bitumen extraction operation from 1982 to 1985.

B.3 PRESENT EXPLORATION AND DEVELOPMENT ACTIVITY

45   Currently, no tar sands development activities are underway on public lands in Utah.
46 According to the Utah Office of Energy Policy (Wright 2006), the only ongoing tar sands

1   operations in Utah are small pilot-scale and exploration operations and a few small mining
2   operations by counties to recover road materials (including operations by Uintah County to
3   excavate materials at Asphalt Ridge for road surfacing). The Utah Division of Oil, Gas and
4   Mining expects to see several of the pilot operations expand to large mines ranging from 5 to
5   possibly 80 acres in size. Specifically, the Division projects three large mines (two on private
6   and one on state lands) and eight small mines (one on private and seven on state lands) in the
7   future.
8
9   For several years, Nevtah Capital Management Corp. and its joint venture partner, Black
10 Sands Energy (formerly known as Cassandra Energy, Inc.), have been working to develop an oil
11 extraction technology for commercial tar sands development. Initial tests were conducted at the
12 Asphalt Ridge STSA. On August 1, 2006, the companies announced the completion of
13 construction of their first commercial production unit, which was built off-site and has a
14 production capacity of 400 to 500 bbl/day of syncrude. The companies hold a total of 13 leases
15 covering 11,000 acres within the Asphalt Ridge, Sunnyside, and P.R. Spring STSAs
16 (Nevtah Capital Management Corp. 2006).
17
18   An application for a commercial tar sands lease covering 2,100 acres on public lands in
19 Asphalt Ridge STSA was submitted to the BLM in 2011 and is currently under review.
20
21

B.4 RECOVERY OF TAR SANDS

24   Recovery methods can be categorized as
25 either mining activities or in situ processes.
26 Mining consists of using surface or subsurface
27 mining techniques to excavate the tar sands with
28 subsequent recovery of the bitumen by washing,
29 flotation, or retorting. In situ techniques recover
30 the bitumen without physically excavating the tar
31 sands. Some techniques combine mining
32 techniques and in situ techniques. In situ recovery
33 is sometimes further categorized as true in situ or
34 modified in situ. True in situ methods generally
35 involve either heating the tar sands or injecting
36 fluids into them to mobilize the bitumen for
37 recovery (Speight 1990, 1995, 1997). There are at
38 least two types of modified in situ methods. The
39 first involves fracturing the tar sands with
40 explosives to increase the permeability of the
41 deposit (National Academy of Sciences 1980);
42 the second process combines true in situ
43 processes with mining techniques (Speight 1990).
44
45   Depending on production costs and the
46 price of the synthetic crude produced, surface

Potential Tar Sands Recovery Processes

Mining
- Surface
- Subsurface

In Situ
- Thermal
  - Steam and hot water
    - Stimulation
    - Flood
  - Combustion
    - Forward
    - Reverse: wet, dry
  - Electrical
  - Nuclear
- Nonthermal
  - Diluents
    - Miscible displacement: hydrocarbons, inert gases, carbon dioxide
    - Solvent
    - Chemical: polymer, caustic, surfactant polymer
  - Emulsification
  - Bacterial

Source: Based on Speight (1997).

1 mining operations are generally cost-effective only where the overburden is no more than about
2 45 m (150 ft) (Meyer 1995). In situ processes requiring high pressures are generally considered
3 to require a thick overburden of about 150 m (500 ft) to contain the pressure. Between these
4 depths, bitumen must be extracted by other means.
5
6
7 **B.4.1 Direct Recovery Mining Technologies**
8
9   Surface mining methods can be used to mine the tar sands for subsequent recovery of
10 bitumen. Subsurface mining has been proposed but has not been applied because of the fear of
11 collapse of the sand deposits (Speight 1990). For this reason, only surface mining is discussed
12 below. However, subsurface mining techniques are employed in some modified in situ recovery
13 methods.
14
15   Surface mining requires conventional earthmoving and mining equipment (BLM 1984).
16 Development begins with the construction of access roads and support facilities. Major mining
17 activities during extraction include the following:
18
19   •   Removing vegetation;
20
21   •   Stripping, stockpiling, and disposal of topsoil;
22
23   •   Removing and disposing of overburden;
24
25   •   Excavating of tar sands; and
26
27   •   Reclamation of the mined area.
28
29   Operations begin with the removal of topsoil and overburden. Topsoil is stockpiled,
30 protected from erosion, and used for reclamation. Erosion and runoff can be reduced by
31 depositing overburden in layers beginning in the bottoms of valleys and building upwards. Later,
32 the deposited overburden can be used for backfilling the pit. It is likely that ultimately the entire
33 area would be disturbed because of actual mining and ancillary activities. Reclamation can
34 proceed as mining progresses and initially mined areas are retired (BLM 1984).
35
36   Disposing of waste sand after extraction of the bitumen is a major concern in any surface
37 mining operation (BLM 1984). Although variable, the bitumen content of waste sand can be as
38 high as 5%. Waste sand can be disposed of by (1) backfilling the mined area, (2) filling valleys,
39 or (3) using tailings ponds. Tailings ponds need to be constructed to keep tailings from sliding, to
40 preclude outside runoff from entering the ponds, and to control seepage from the ponds.
41
42   In Utah, less than 15% of the tar sands may be shallow enough for strip mining; the
43 deposits at the Asphalt Ridge, P.R. Spring, and Sunnyside STSAs appearing to be most suitable
44 (BLM 1984; National Academy of Sciences 1980). The Athabasca deposits are currently being
45 recovered by surface mining.
46

1   The equipment used for surface recovery includes a combination of excavation
2   equipment, to remove the sands from their original location, and conveying equipment, to move
3   the excavated sand to another location. Depending upon the approach chosen, tar sands removal
4   equipment can include draglines, bucketwheel excavators, power shovels, scrappers, bulldozers
5   and front-end loaders. Conveying equipment can include belt conveyors, large trucks (typically
6   150–400 tons), trains, scrapers, and hydraulic systems (Speight 1995).
7
8   Surface excavation is conducted by using two basic approaches. The first uses a small
9   number of large, custom-made, expensive bucketwheel excavators and drag lines along with belt
10 conveyors. The second uses a large number of smaller, conventional, less expensive equipment.
11 Initially, the major developers of the Athabasca oil sands in Canada used bucketwheels or
12 draglines, they now use a truck and shovel approach. Truck and shovel mining is more mobile,
13 can be moved more easily to the richest deposits, and requires less maintenance than the custom
14 bucketwheels and draglines. The larger number of units in operation also means that equipment
15 breakdown has much less impact on overall production.
16
17 Today, hydrotransport provides an alternative to the use of belt conveyors between the
18 mining pit and the extraction plant (Oil Sands Discovery Center 2006b). The oil sands are
19 crushed at the mine site, mixed with warm water, and moved by pipeline to the extraction plant.
20 Hydrotransport improves efficiency by initiating the extraction of bitumen while the oil sands are
21 being transported to the extraction plant. However, its application in arid areas such as Utah may
22 be problematic.
23
24 Speight (1995) identifies the following possible problems that may be encountered when
25 mining tar sands deposits:
26
27 •   The clay shale overburden and sand may swell when exposed to fresh water,
28
29 •   Pit wall slopes may slough off and may need to be controlled by preblasting or
30   excluding heavy equipment from slope crests,
31
32 •   The abrasive sands cause a high rate of equipment wear, and
33
34 •   The large quantity of tailings from the extraction process requires disposal.
35
36 Table B-2 provides available data describing potential impact-producing factors that
37 could be associated with a tar sands surface mine. These data were derived from information
38 published by Daniels et al. (1981) on the basis of a proposed 20,000-bbl/day-capacity plant
39 designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick,
40 California. The volatile emissions data presented in this table are likely to exceed those that
41 would be expected from one of the Utah tar sands deposits because the bitumen is more volatile
42 at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah
43 deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the
44 sandstone deposits in Utah. The table presents the original numbers estimated for the McKittrick
45 project and extrapolated numbers for larger operations. It should be noted that the numbers were
46

1
2
3

TABLE B-2 Potential Impact-Producing Factors Associated with a Tar Sands Surface Mine Operating at a Diatomaceous Earth Tar Sands Deposit

Impact-Producing Factor[a]	Production Capacity (bbl/day syncrude)[b,c]			
	20,000	25,000	50,000	100,000
Total land disturbance (acres)	1,000	1,250	2,500	5,000
Water use (bbl/day)[d]	25,160	31,450	62,900	125,800
Noise (dBA at 500 ft)	61	–[e]	–	–
Processed sand (tons/day)	52,000	65,000	130,000	260,000
Air emissions (tons/yr)[f]				
Mining equipment				
TSP	70	87	174	348
SO_x	70	87	174	348
NO_x	905	1,131	2,262	4,524
CO	383	479	957	1,914
THC	104	131	261	522
Crushing apparatus[g]				
TSP	7	9	17	35
Mine pit and storage[h]				
TSP	1,009	1,262	2,523	5,046
THC	35	44	87	174

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; THC = total hydrocarbons (includes methane and photochemically nonreactive compounds); TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter).

[b] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[c] Data taken from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[d] Approximately 3.5% of the process water would need to be fresh water (Daniels et al. 1981).

[e] A dash indicates noise level determined by modeling, not by extrapolation.

[f] The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

[g] Assumes 99.5% emissions control via the baghouse.

[h] Assumes 80% dust suppression by virtue of the natural oil in the tar sands combined with water application.

1 extrapolated linearly because no information is available to justify doing otherwise; linear
2 extrapolations are likely to result in conservative overestimates of potential impacts.
3
4   Table B-3 provides available data describing potential air emissions from a tar sands
5 surface mine on the basis of data published by Aerocomp, Inc. (1984), for a proposed
6 32,500-bbl/day-capacity project in the Sunnyside STSA. These data may more accurately reflect
7 emissions from a surface mine excavating sandstone-based tar sands deposits as opposed to the
8 emissions presented in Table B-2 for the diatomaceous earth tar sands deposit.
9
10
11 **B.4.2 In Situ Methods**
12
13   Given the environmental problems associated with mining and the fact that the majority
14 of tar sands lie under an overburden too thick to permit their economic removal, nonmining
15 recovery of bitumen may be a practical alternative. This is especially true in U.S. deposits where
16 the terrain and the character of the tar sands may not be favorable for mining. However, the
17
18
19 **TABLE B-3 Potential Air Emissions from a Surface Mine Operating at a**
20 **Sandstone-Based Tar Sands Deposit[a]**

Air Emissions[b]	Production Capacity[c,d]			
	20,000 bbl/day syncrude (tons/yr)	32,500 bbl/day syncrude (tons/yr)	50,000 bbl/day syncrude (tons/yr)	100,000 bbl/day syncrude (tons/yr)
TSP	2,814	4,573	7,035	14,071
SO_x	335	544	837	1,674
NO_x	5,276	8,573	13,189	26,378
CO	1,047	1,701	2,617	5,234
VOC	338	549	322	1,689

[a] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

[b] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

[c] bbl = barrel; 1 bbl syncrude = 42 gal.

[d] The air emissions data were derived from information published by Aerocomp, Inc. (1984) for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

21
22

1   physical properties of Utah tar sands and the bitumen may constrain application of nonmining
2   methods; Utah sands tend to be low-porosity, low-permeability, consolidated to unconsolidated
3   sands, and the bitumen does not flow under reservoir conditions. Low permeability and porosity
4   require fluids to be injected at pressures sufficient to cause fracturing, which can result in
5   undesirable flow pathways (e.g., direct communication between the injection well and the
6   production well) (Speight 1990).
7
8   In situ or nonmining methods are basically enhanced or tertiary oil recovery techniques
9   that require injecting a "heating" and "driver" substance into the tar sands formation through
10 injection wells to reduce the viscosity of and displace the bitumen so that it can be recovered
11 through conventional liquid production wells (Speight 1997). For a given technique, there could
12 be considerable variation in the efficiency of extracting bitumen between different sites, for
13 example, between water-wet Athabasca sands and oil-wet Utah sands (BLM 1984).
14
15   All in situ recovery processes must perform the following:
16
17 •   Establish fluid flow between injection and production wells;
18
19 •   Reduce the viscosity of the bitumen by heating it or dissolving it in a solvent
20   so that it will flow to the production well; and
21
22 •   Maintain the flow of bitumen after it has started.
23
24   Heat could be supplied either from steam from surface boilers or by combustion of part
25 of the bitumen in situ. In addition, the deposit should be permeable or susceptible to fracturing to
26 make it permeable and reasonably stable so that it does not compact structurally (i.e., collapse)
27 and lose permeability as bitumen is removed (BLM 1984).
28
29   Briefly, development of an in situ facility would include the following processes:
30
31 •   Exploration to characterize the formation hydrogeologically;
32
33 •   Drilling of injection and production wells;
34
35 •   Installation of production equipment;
36
37 •   Recovery, processing, and upgrading of bitumen to produce synthetic crude
38   oil;
39
40 •   Removal of equipment at the close of operations; and
41
42 •   Reclamation.
43
44   Numerous, closely spaced holes would be required for injection and production wells,
45 with production wells probably spaced within 150 m (500 ft) of each other. The exact number
46 and the spacing of the wells would be governed by the characteristics of the formation. Surface

1   equipment would vary by the method used but would include drilling rigs, compressors, pumps,
2   piping, storage tanks, waste pits, and pits or tanks for drilling fluids and process water storage
3   and recycling. For most processes, especially those involving steam injection, boilers and steam
4   pipes would also be required. Facilities for treating condensate and water for recycling would
5   also be needed. Ancillary facilities could include shops, warehouses, offices, outside storage
6   areas, fuel storage, housing, and roads (BLM 1984).
7
8   Over time, different parts of the site would be developed, and production equipment
9   would be moved from one area to another as the recoverable bitumen was exhausted. Upgrading
10 equipment would be centrally located and would probably not be moved over the life of the site.
11 After the production equipment had been moved, the depleted site could be reclaimed. The
12 amount of surface disturbance from development of in situ recovery facilities would depend on
13 topography and the characteristics of the bitumen and the surrounding rock. Estimates of surface
14 disturbance range from 10 to 60% of the site and are expected to be similar for most in situ
15 methods. The use of directional drilling techniques tends to reduce the amount of surface
16 disturbance (BLM 1984). In addition to the disturbances resulting directly from surface
17 activities, subsidence may also occur and require remediation.
18
19

B.4.2.1 Combustion Processes and Modifications

21
22   In combustion processes, the bitumen itself is ignited. Once ignition has been achieved,
23 partial or complete combustion must be maintained for a period of about 30 to 90 days.
24 Temperatures can range from about 600 to 1,200°F. Control of the amount of air injected
25 regulates the rate at which bitumen is burned and hence the temperature. Several regions exist
26 within the reservoir. Just ahead of the fire front, heat breaks the oil down (by cracking and
27 distillation). The cracking provides a partial upgrading of the bitumen recovered from the
28 production wells. Lighter fractions of the bitumen vaporize and move toward cooler portions of
29 the formation and exchange their heat with it, displacing some of the bitumen and increasing
30 recovery efficiency. As the vapors move into cooler parts of the deposit, they condense and can
31 be pumped out of production wells. Condensation could cause a problem by plugging the
32 deposit. Heavier fractions remain behind as coke that includes heavy hydrocarbons containing
33 oxygen, sulfur, nitrogen, and trace metals. Coke may account for up to 20% of the oil and
34 provides most of the combustion fuel. The burned region consists mostly of sand
35 (Schumacher 1978; Speight 1990, 1997).
36
37   The use of combustion or fire flooding to stimulate bitumen production may be attractive
38 for deep reservoirs because little heat is lost. Conversely, heat loss limits the use of steam
39 injection in deep reservoirs. The high pressures involved in injecting combustion air preclude the
40 use of combustion in shallow deposits. Another advantage of combustion over steam-based
41 processes is the reduction of carbon dioxide (CO_2) emissions from aboveground steam
42 generators. However, CO_2 from in situ combustion will be present in the produced gases
43 recovered from production wells. Combustion has been effective in the recovery of heavy oils
44 from thick reservoirs where the dip and continuity of the formation may assist gravity flow of
45 bitumen or where wells can be closely spaced (Schumacher 1978; Speight 1990, 1997;
46 Isaacs 1998).

1   With the exception of the fuel needed to initiate combustion, there is no need to buy fuel
2 to produce heat in the well (Schumacher 1978). However, any bitumen in the combusted coke
3 cannot be recovered as product. Some of the advantage also is lost by the need to compress the
4 injection air and the increased loss of heat to the formation at the elevated temperatures
5 associated with burning. This loss can be reduced by injecting water at the same time or
6 alternatively with the combustion air.
7
8   Far less experience and information are available for in situ combustion than for steam
9 processes, and process control is more difficult. Some considerations include:
10
11   • Sufficient bitumen must be consumed to raise the temperature enough to
12   mobilize the remaining bitumen,
13
14   • Sufficient oxygen must be supplied to support and control combustion,
15
16   • Overburden and underburden must provide effective seals for injected air and
17   mobilized bitumen and serve as effective barriers to heat loss (Speight 1990).
18
19   The combustion in in situ processes can be categorized as forward, reverse, or a
20 combination of forward and reverse. In forward combustion (Figure B-3), the fire front is ignited
21 at the injection well and moves toward the production well. As the bitumen moves toward the
22 production well, it moves from the zone of combustion into a colder, unheated portion of the
23 formation. Because the bitumen is generally less mobile when it is colder, the forward
24 combustion process has an upper limit on the viscosity of liquids that can be recovered. Up to
25 80% of the combustion heat remains behind the advancing fire front and is lost. However,
26 because the air passes through the hot formation behind the flame front prior to reaching the
27 combustion zone, combustion efficiencies are enhanced and more unburned hydrocarbons are
28 recovered. Heavier components are left on the sand grains and consumed as fuel. Deposits with
29 relatively high permeability and relatively low bitumen saturation (45−65 vol%) are most
30 amenable to this process. Forward combustion has been used with some success in the Orinoco
31 deposits in Venezuela and in Kentucky sands (Schumacher 1978; Speight 1990, 1997;
32 Meyer 1995).
33
34   In reverse combustion (Figure B-3), the fire front is ignited at the production well and
35 moves toward the injection well. Combustion air introduced at the injection well helps drive the
36 volatile organics toward the production well. Because combustion products and product move
37 into the hot zone behind the fire front, there should be less of a viscosity limitation. Residual
38 coke would remain on the sand grains. This process is most applicable to deposits with lower
39 permeability because movement of mobilized fluids would be into a hot zone with a consequent
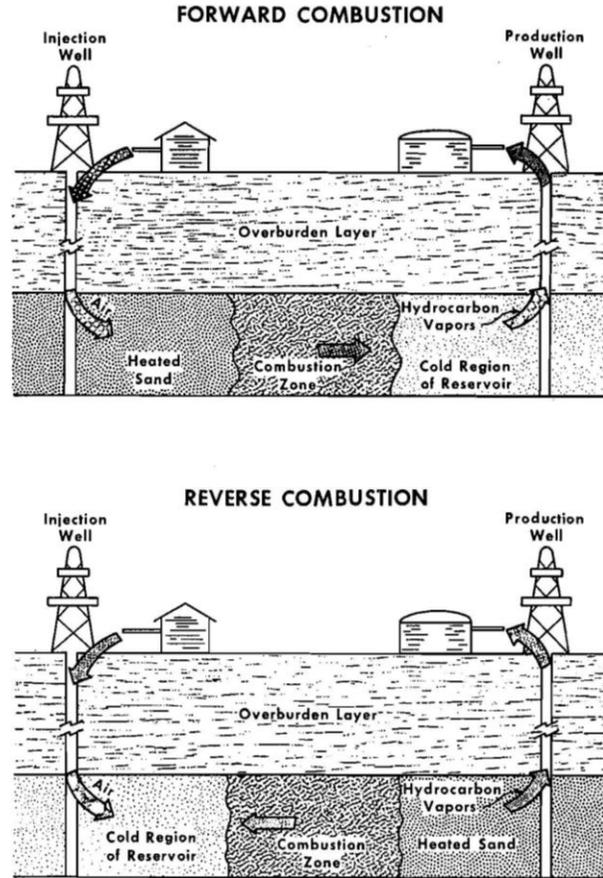40 reduction in plugging (Speight 1990, 1997; Meyer 1995).
41
42   In a combination of reverse and forward combustion, the initial phase uses a
43 low-temperature reverse combustion to increase the permeability of the formation and increase
44 the mobility of the bitumen. The subsequent forward combustion phase supplies the heat and
45 energy to distill and mobilize the bitumen and move it to the production wells (Marchant and
46 Westhoff 1985).

1   Modifications of the in situ combustion
2 process include fracturing by either pneumatic
3 or hydraulic means to increase permeability of
4 reservoirs so that combustion air can flow
5 more freely. In another modification, oxygen
6 or oxygen-enriched air rather than atmospheric
7 air is injected under certain conditions. Cost
8 savings accrue because of the reduced
9 compression costs and the reduction in the gas-
10 to-oil ratio in the recovered product.
11
12   In the wet combustion modification,
13 water and air are injected alternatively into the
14 formation. The water flows through the fire,
15 vaporizes, and then condenses, thereby heating
16 the unburned deposit and reducing the
17 viscosity of the bitumen. Wet combustion can
18 move heavier oils and operate at lower
19 pressures than dry combustion and may burn
20 less bitumen, resulting in a reduced need for
21 injected air (Schumacher 1978; Speight 1990,
22 1997).
23
24   A combination of forward combustion
25 and waterflooding has also been tried at
26 Athabasca. It involved a heating phase
27 followed by a production or blowdown phase
28 followed by a displacement phase using a
29 fire-water flood, over a period of 18 months
30 (8 months heating, 4 months blowdown, and
31 6 months displacement) (Speight 1990).

FIGURE B-3 Simplified Diagrams of Forward and Reverse Combustion Processes (Speight 1990) (Copyright 1990 from *Fuel Science and Technology Handbook* edited by James G. Speight. Reproduced by the permission of Routledge/Taylor & Francis Group, LLC.)

32
33   Table B-4 provides available data describing potential impact-producing factors that
34 could be associated with in situ combustion processes. The air emissions data were derived from
35 information published by Aerocomp, Inc. (1984), for a proposed 20,000-bbl/day-capacity project
36 in the Circle Cliffs STSA (based upon parameters for an oil shale processing facility) and include
37 emissions from upgrading processes. The nonair emissions data were derived from information
38 published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant
39 designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick,
40 California. The table presents the original numbers estimated for each project and extrapolated
41 numbers for larger operations. It should be noted that the numbers were extrapolated linearly
42 because no information is available to justify doing otherwise; linear extrapolations are likely to
43 result in conservative overestimates of potential impacts.
44
45
46

1   **TABLE B-4 Potential Impact-Producing Factors Associated with**
2   **In Situ Combustion Processes**

|	Production Capacity (bbl/day syncrude)[b,c]			
Impact-Producing Factor[a]	20,000	25,000	50,000	100,000
Total land disturbance (acres)	4,000	5,000	10,000	20,000
Produced wastewater (bbl/day)[d]	40,000	50,000	100,000	200,000
Air emissions (tons/yr)				
Stack emissions[e]				
TSP	438	548	1,095	2,190
SO_x	4,960	6,200	12,400	24,800
NO_x	2,052	2,565	5,130	10,260
CO	60	75	150	300
VOC	110	138	275	550
Fugitive emissions[f]				
TSP	409	511	1,022	2,045
SO_x	4	5	10	20
NO_x	7	9	18	35
CO	48	60	120	240
VOC	2	3	5	10

[a]   CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides;
      TSP = total suspended particulates (includes all particulate matter up to
      about 100 μm in diameter); VOC = volatile organic compound.

[b]   The air emissions data were derived from information published by
      Aerocomp, Inc. (1984), for a proposed 20,000-bbl/day-capacity project in
      the Circle Cliffs STSA (based upon parameters for an oil shale processing
      facility). Nonair emissions data were derived from Daniels et al. (1981)
      for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil
      from a diatomaceous earth tar sands deposit near McKittrick, California.
      Numbers for larger production capacities were extrapolated linearly,
      which is likely to result in conservative overestimates of potential
      impacts.

[c]   bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d]   Based upon an estimated generation rate of 1 to 2 bbl of wastewater per
      bbl of syncrude produced.

[e]   Modeled on the basis of the following: stack height = 76 m (249.3 ft),
      stack diameter = 3 m (9.8 ft), velocity = 10 m/s (32.8 ft/s), and
      temperature = 311 K (100.1°F).

[f]   Modeled on the basis of the following: height above ground surface = 3 m
      (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

3
4
5

1   **B.4.2.2 Noncombustion Processes**
2
3   The noncombustion processes discussed in this subsection involve the injection of liquid
4   or gas into the reservoir to effect the mobilization and recovery of the bitumen. For steam
5   injection processes, the cost of generating steam is the most significant expense. Also, the
6   feedwater must be of relatively high quality (Speight 1990), which could prove to be an obstacle
7   to using steam injection processes in the arid and semiarid regions of Utah.
8
9   Steam drive (steam flood) processes (Figure B-4) involve the injection of steam from
10   surface boilers into at least one injection well with the recovery of the mobilized bitumen and
11   condensed steam from at least one production well. The wells could be placed either in parallel
12   rows or in a ring around a central well. Heat released by condensing steam reduces the viscosity
13   of the bitumen, which is forced to the production well by the flow of steam and hot water. In situ
14   distillation (upgrading) and improved gas drive are side benefits of this steam drive. This process
15   may be used following cyclic steam injection. The permeability of the reservoir must be
16   sufficient to permit the injection of steam at rates high enough to raise the temperature to the
17   point at which the bitumen will flow. Permeability will decrease as the process proceeds and
18   water and steam saturate the reservoir; as permeability decreases, the amount of injected steam
19   required to produce a unit of oil increases sharply. Establishing communication between the
20   injection and production wells presents a problem for this technique, but it has been successfully
21   utilized by Shell Canada in the Peace River deposit in Alberta. Bitumen-to-water ratios could be
22   as high as 1 to 10 but are generally around 1 to 5. The use of steam has been demonstrated with
23   some success in Utah sands. The large amount of energy required to generate, compress, and
24
25

26
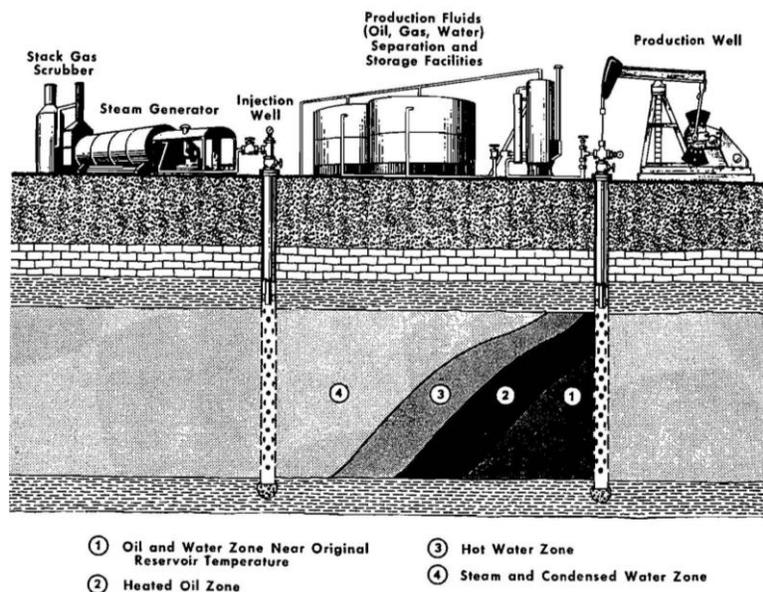
27   **FIGURE B-4 Simplified Steam Drive Process (Speight 1990)**
28   **(Copyright 1990 from *Fuel Science and Technology Handbook***
29   **edited by James G. Speight. Reproduced by the permission of**
30   **Routledge/Taylor & Francis Group, LLC.)**

1 pump steam presents an important technical requirement for steam drive (Spencer et al. 1969;
2 Schumacher 1978; National Academy of Sciences 1980; BLM 1984; Speight 1995; Isaacs 1998).
3
4   The alternative cyclical steam stimulation, also known as "huff and puff," involves
5 injecting high-temperature (about 350ºC [660ºF]) steam from surface boilers at higher than
6 fracturing pressure into the deposit over a period ranging from days to months, followed by a
7 "soak" period of variable length, followed by production for up to a year. Initial production relies
8 on the pressure created by injection followed by pumping (Speight 1990, 1997; Oils Sands
9 Discovery Center 2006b). Cyclic steam has more effect on increasing the rate of production than
10 on increasing the ultimate recovery (Schumacher 1978).
11
12   Another steam injection approach, SAGD, is most suitable for reservoirs with immobile
13 bitumen. It involves drilling two horizontal wells at the bottom of a thick unconsolidated
14 sandstone reservoir. Steam is injected continuously through the upper well at pressures much
15 lower than the fracture pressure. Heat and steam rise and condensed water and mobilized oil flow
16 down by gravity into the lower or production well. As the process proceeds, a "steam chamber"
17 develops laterally and upwards. SAGD seems to be insensitive to horizontal barriers to flow such
18 as shale intrusions that fracture from thermal shock. Recovery ratios of 50 to 75% may be
19 achievable; however, the initial oil recovery rate is low.
20
21   The uses of hot fluids, steam, water, and gas for injection are similar. Hot water is more
22 efficient than hot gas but less efficient than steam mainly because of the relative heat-carrying
23 capacities of the fluids. Nonsteam techniques have been applied to bitumen recovery in
24 conjunction with other techniques (Spencer et al. 1969; BLM 1984).
25
26   Solvent extraction involves the injection of solvent into the formation to dissolve the
27 bitumen and carry it to a production well for pumping to the surface. At the surface, the bitumen
28 is separated from the solvent and the solvent is recovered. When applied in situ, large losses of
29 solvent and bitumen have always presented major problems that must be controlled. In addition,
30 the only useful solvents, at least for Athabasca bitumen, are relatively expensive naphthenic and
31 aromatic substances. Solvent extraction has not generally been economical compared with steam
32 injection.
33
34   Two aqueous emulsifying systems have been developed for use in the Athabasca sands
35 (Spencer et al. 1969). One employs an alkaline surfactant solution, the other a dilute sodium
36 hydroxide solution. Field tests showed that bitumen was completely removed from the contacted
37 portion of the reservoir but that the contacted portion was very limited because of the low
38 permeability of the reservoir.
39
40   Several variations of steam heating and emulsification have been tried (Speight 1990).
41 These include the use of steam with various solvents to reduce the viscosity of the oil through a
42 combination of heating and dissolution. A technique involving fracturing by using dilute aqueous
43 alkaline solutions followed by emulsification with hot caustic and production of an emulsion by
44 using steam injection at the production wellhead was used in the Athabasca sands. It was
45 estimated that more oil had leaked away from the recovery zone than had been recovered.
46

Many additional processes are in the concept or early development phase or for which patents have been sought or issued. Some of those that potentially could be applied within the 20-year planning horizon of this PEIS include the following:

- *Top-Down Combustion*, in which combustion would be initiated and maintained by the injection of air at the top of the reservoir with the heated, mobilized oil draining into horizontal wells by gravity (Isaacs 1998).

- *Cyclic Steam Combined with Steam-Assisted Gravity Drainage Gravity* (Isaacs 1998).

- *Warm Vapor Extraction*, which involves the injection of vaporized solvents to create a vapor chamber through which mobilized hydrocarbons flow because of gravity drainage.

- *Toe-to-Heel Air Injection*, which combines a vertical air injection well with a horizontal production well. A combustion front is created and combusts part of the hydrocarbon in the reservoir. The heat generated reduces the viscosity of the hydrocarbon that is pulled to the horizontal production well by gravity. The combustion front moves from the "toe," the underground end of the horizontal production well, to the "heel," where the production well transitions from horizontal to vertical.

- *Pressure Pulse Flow Enhancement Technology*, which is based on the recent discovery that large-amplitude, low-frequency energy waves can enhance flow rates in porous media (Dusseault 2001).

- *Nuclear Energy*, which has been proposed as an energy source for producing a combination of steam and electricity for tar sands recovery while reducing CO_2 emissions (Donnelly and Pendergast 1999; Dunbar and Sloan 2003).

Table B-5 provides available data describing potential impact-producing factors that could be associated with in situ steam injection processes. The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 50,000-bbl/day-capacity project in the P.R. Spring STSA and a proposed 20,000-bbl/day-capacity project in the San Rafael Swell STSA and include emissions from upgrading processes. The nonair emissions data were derived from information published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The table presents the original numbers estimated for each project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

1
2

**TABLE B-5 Potential Impact-Producing Factors
Associated with In Situ Steam Injection Processes**

Impact-Producing Factor[a]	Production Capacity (bbl/day syncrude)[b,c]		
	20,000	50,000	100,000
Total land disturbance (acres)	4,000	10,000	20,000
Water use (bbl/day)[d]	100,000	250,000	500,000
Air emissions (tons/yr)			
Stack emissions[e]			
TSP	358	1,155	2,310
SO_x	6,758	16,896	33,792
NO_x	5,332	13,332	26,664
CO	712	1,782	3,564
VOC	356	889	1,778
Fugitive emissions[f]			
TSP	615	895	1,790
SO_x	0	1	2
NO_x	1	2	4
CO	4	11	22
VOC	0.4	1	2

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

[b] The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 50,000-bbl/day-capacity project in the P.R. Spring STSA and a proposed 20,000-bbl/day-capacity project in the San Rafael Swell STSA. Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Based upon an estimated use rate of 5 bbl of water per bbl of syncrude produced.

[e] Modeled on the basis of the following: for the 20,000-bbl/day facility, stack height = 76 m (249.3 ft); stack diameter = 5 m (16.4 ft); velocity = 12 m/s (39.4 ft/s); and temperature = 493°K (427.7°F). Modeled on the basis of the following: for the 50,000-bbl/day facility, stack height = 76 m (249.3 ft); stack diameter = 7 m (23 ft); velocity = 12 m/s (39.4 ft/s); and temperature = 473 K (391.7°F).

[f] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

1   **B.4.3 Modified In Situ**
2
3   The use of explosives to disaggregate the tar sands and increase permeability is similar to
4   the process used for oil shale (see Appendix A) and is not discussed further here.
5
6   As noted above, methods for recovering bitumen from formations located at depths
7   between about 45 and 150 m (150 and 500 ft) are limited. In comparison with surface mining,
8   subsurface mining reduces the need for raw tar sands handling and storage; the need for handling
9   and disposal of spent sand (tailings); and the need for reclamation of a mined out pit, room, or
10 shaft. One potential extraction method applicable at these depths involves combining in situ and
11 subsurface mining techniques. This process, referred to as oil mining, has been used in the past
12 in France, Germany, and Russia and entails underground mining of some of the tar sands deposit
13 so that in situ methods can be used on the remaining deposit. Most commonly, a vertical shaft is
14 sunk and horizontal drifts are excavated from the bottom of the shaft. Horizontal injection and
15 production wells are drilled from the drifts. The drifts can be above or below the tar sands
16 formation and are typically used to permit low-pressure steam to be injected into the formation to
17 heat the sands so that the bitumen will flow (Meyer 1995; Isaacs 1998).
18
19
20 **B.5 PROCESSING RECOVERED BITUMEN**
21
22   The choice of recovery method affects which processing operations are used. In mining
23 operations, the mined bitumen must be processed to recover or separate it from the inorganic
24 matrix (largely sand, silt, and clay) in which it occurs. Nonmining extraction produces bitumen
25 mixed with water, steam, other gases, or solvent from which it must be separated. If combustion
26 recovery is used, the viscosity of the recovered bitumen may need to be reduced prior to further
27 processing. If steam, water, or gas injection is used, the injection fluid would need to be
28 separated from the bitumen. In all cases, the viscosity of the bitumen might need to be changed
29 prior to further processing and upgrading (BLM 1984). Depending on the recovery method,
30 mining operations may also need to perform similar separations.
31
32
33 **B.5.1 Hot Water Process**
34
35   The hot water process has been applied with commercial success to mined water-wet
36 Athabasca sands (see Figure B-5). As of 1997, it was the only process to have been applied with
37 commercial success to mined tar sands in North America (Speight 1997). There are three main
38 steps: conditioning, separation, and scavenging.
39
40   There are two methods of conditioning. In the first, mined tar sands are pumped with
41 water and caustic into a conditioning drum at 180 to 220°F to reduce particle size and digest the
42 bitumen. The resulting slurry is screened to remove undigested material, and lumps are sent to a
43 separation cell. In the newer hydrotransport method, the tar sands are crushed at the mine site
44 and moved by pipeline in a water slurry to the extraction plant (Marchant and Westhoff 1985;
45 Speight 1997; Oil Sands Discovery Center 2006b).
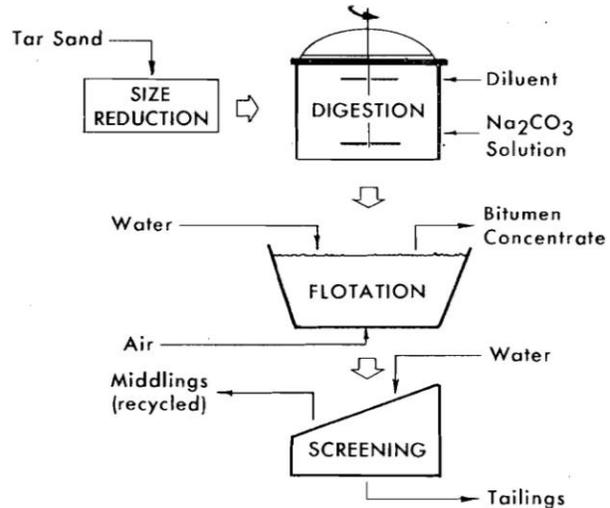46

1   The separation cell operates like a
2 settling vessel. Sand settles downward to be
3 removed, as tailings and bitumen float to the
4 top where they are skimmed off. Most of the
5 middlings, an emulsion for bitumen and water,
6 are sent to scavenger cells for additional
7 bitumen removal by froth flotation (Marchant
8 and Westhoff 1985; Speight 1997).
9
10   Experiments have been conducted to
11 develop a hot water process for the oil-wet tar
12 sands deposits in Utah (Speight 1997;
13 Marchant and Westhoff 1985). The absence of
14 a sheath of water around the tar sands particles
15 and the strong bonding directly between the
16 sand and the bitumen suggest that more energy
17 would be required to separate sand and
18 bitumen in the Utah tar sands than would be

FIGURE B-5 Simplified Diagram of Hot Water Recovery Process (Marchant and Westhoff 1985)

19 required in the Athabasca tar sands. After size reduction, digestion is accomplished using a high
20 shear energy digester stirred at about 750 rpm at 200°F. Next, bitumen is separated by modified
21 froth flotation. Middlings are screened and recycled (Oblad et al. 1987). This process has been
22 developed to the pilot plant stage (Figure B-5), processing 125 tons/day of tar sands to produce
23 50 to 100 bbl/day of oil (Speight 1990).
24
25   Disposal of tailings presents a problem for hot water recovery processes (Speight 1997).
26 The volume of material expands during processing. A ton of in situ tar sands has a volume of
27 about 16 ft^3 and produces about 22 ft^3 of tailings, a volume increase of almost 40%. The tailings
28 stream contains about 49 to 50 wt% sand, about 1 wt% bitumen, and about 50 wt% water
29 (Speight 1990). Regulations preclude dumping these tailings in streams or rivers or in areas from
30 which runoff may enter rivers or contaminate groundwater. Reclamation of the tailings must also
31 be accomplished upon site closure.
32
33   In some operations, recovery of bitumen from the middlings in scavenger cells may be
34 economical, the goal being an additional 2 to 4% bitumen recovery. This process generally
35 involves injecting air in a froth flotation process. Froth containing bitumen rises to the surface of
36 the cell and is skimmed off.
37
38   The froths from the separation vessel and the scavenger cells are combined and sent for
39 further processing. The froth stream is usually diluted with naphtha and centrifuged. At this
40 stage, the bitumen contains 1 to 2 wt% minerals and 5 to 15 wt% water and is ready for
41 upgrading.
42
43
44

1   **B.5.2 Cold Water Process**
2
3   Operations in the Athabasca tar sands have changed from hot water processing to cold
4   water processing, which uses less energy. This change was made possible by using slurry
5   pipelines rather than belt conveyors to transport ore from the mine to the extraction facility.
6   Mined sand is crushed at the mine site, mixed with warm water to form a slurry, and moved by
7   pipeline to the extraction plant. Partial separation of the bitumen from the sand occurs in the
8   pipeline (Singh et al. 2005; Oil Sands Discovery Center 2006b).
9
10   Experiments with cold water extraction of Utah tar sands showed a removal of more than
11   60% of the sand with easily accomplished water removal. Calculations indicated that for 90%
12   recovery of the bitumen, hot water processing would require at least 45 kWh/ton, while cold
13   water processing would require only 13 kWh/ton (Oblad et al. 1987).
14
15   Bench-scale cold water processes have also been developed. The sand reduction process
16   uses cold water and no solvent to provide a feed for a fluid coking upgrading process. Tar sands
17   are mixed with water in a screw conveyor and discharged to a screen of appropriate mesh in a
18   water-filled settling vessel. Bitumen agglomerates on the screen and is removed while the sand
19   passes through and is removed as waste.
20
21   In the spherical agglomeration process, water is added to the tar sands and the mixture is
22   sent to a ball mill. The bitumen agglomerates to particles with at least 75 wt% bitumen
23   (Speight 1990, 1997).
24
25
26   **B.5.3 Processes Involving Solvents**
27
28   Solvent extraction without water has been attempted. It generally uses a low boiling point
29   hydrocarbon (such as heptane, cyclohexane, or ethanol) and involves four main steps. Fresh tar
30   sands are mixed with recycled solvent containing some bitumen, water, and minerals. Next, a
31   three-stage countercurrent wash is used with settling and draining of about 30 minutes after each
32   stage forming a bed of sand through which the bitumen containing solvent is drained. The last
33   two steps recover the solvent from the sand. Solvent extraction has been demonstrated for
34   Athabasca, Utah, and Kentucky sands, but the cost of solvent losses has kept the process from
35   going commercial (Speight 1997).
36
37   Experiments have been carried out on various tar sands deposits, including those at the
38   Asphalt Ridge and Sunnyside STSAs, by using kerosene to control the viscosity of the bitumen
39   to improve bitumen recovery and tailings sedimentation. The temperatures involved have been
40   lowered from near the boiling point of water 100°C (212°F) to around 50 to 55°C (120–130°F).
41   More than 92% of the bitumen in the concentrate was recovered (Oblad et al. 1987).
42
43   The cold water bitumen separation process using a combination of cold water and a
44   solvent has been used in a small-scale pilot plant (Speight 1997). The tar sands are first mixed
45   with water, reagents, and a diluent, which may be a petroleum fraction such as kerosene. The
46   solution is maintained in an alkaline condition. Then sand is removed by settling in a clarifier

1   from which the water and oil overflow is sent to thickeners to concentrate the oil. Clay in the
2   feed emulsifies and carries off some of the bitumen as waste from the thickeners.
3
4   Table B-6 provides available data describing potential impact-producing factors that
5   could be associated with solvent extraction processes. The air emissions data were derived from
6   information published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project
7   in the Sunnyside STSA and include emissions from upgrading processes. The nonair emissions
8   data were derived from information published by Daniels et al. (1981) on the basis of the
9   proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth
10 tar sands deposit near McKittrick, California. The table presents the original numbers estimated
11 for each project and extrapolated numbers for larger or smaller operations. It should be noted that
12 the numbers were extrapolated linearly because no information is available to justify doing
13 otherwise; linear extrapolations are likely to result in conservative overestimates of potential
14 impacts.
15
16
17 **B.5.4 Thermal Recovery Processes**
18
19   Various schemes have been proposed as alternatives to the hot water process to remove
20 bitumen from mined tar sands by applying heat. Direct coking or thermal recovery processes
21 appeared promising but the success of hydrotransport in making cold water extraction
22 commercially successful in Athabasca has helped reduce the attractiveness of thermal recovery,
23 which can require consumption of a substantial amount of heat (Marchant and Westhoff 1985).
24
25   In most processes, the tar sands are pyrolyzed (heated in an inert or nonoxidizing
26 atmosphere) by heating at 900°F to effect chemical changes, including
27
28   •   Volatilization of low molecular weight components,
29
30   •   Cracking of some heavier components, and
31
32   •   Conversion of part of the bitumen to coke.
33
34   The volatile materials exit the reaction vessel, are cooled, and separated into gases and
35 condensed liquids while the coke remains behind adhering to the sand, which is transferred to a
36 combustion vessel for burning to provide heat for the process. In general, the oil obtained by a
37 thermal process would require upgrading before it is acceptable as a refinery grade synthetic
38 crude. The sulfur- and nitrogen-containing compounds must be eliminated, the nitrogen and/or
39 sulfur converted to compounds that are subsequently removed (typically ammonia and hydrogen
40 sulfide, respectively) and further processed into saleable commodities or disposed of as waste,
41 the average molecular weight lowered, and the carbon-to-hydrogen ratio reduced (Marchant and
42 Westhoff 1985; Speight 1990).
43

1
2

TABLE B-6 Potential Impact-Producing Factors Associated with a Solvent Extraction Facility

Impact-Producing Factor[a]	Production Capacity (bbl/day syncrude)[b,c]			
	20,000	32,500	50,000	100,000
Total land disturbance (acres)	2,600	4,225	6,500	13,000
Water use (bbl/day)[c,d]	106,930	173,760	267,330	534,650
Noise (dBA at 500 ft)	73–88	–[e]	–	–
Air emissions (tons/yr)[e,f]				
Extraction plant[e]				
TSP	422	686	1,055	2,110
SO_x	632	1,027	1,580	3,161
NO_x	4,990	8,109	12,475	24,950
CO	239	389	598	1,196
VOC	118	193	296	592
Upgrading plant[g]				
TSP	139	225	346	693
SO_x	94	153	235	470
NO_x	4,522	7,348	11,305	22,610
CO	217	352	542	1,084
VOC	107	174	268	537
Spent tar sands[h]				
TSP	825	1,340	2,062	4,123
SO_x	46	75	115	231
NO_x	750	1,218	1,874	3,748
CO	129	209	322	643
VOC	39	63	97	194

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

[b] The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Approximately 22% of the process water would need to be fresh water (Daniels et al. 1981).

[e] A dash indicates noise level not calculated.

[f] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

Footnotes continued on next page.

TABLE B-6 (Cont.)

g   Modeled on the basis of the following: stack height = 33 m (108.3 ft), stack diameter = 5 m (16.4 ft), velocity = 12 m/s (39.4 ft/s), and temperature = 393 K (247.7°F). Values derived from the original source on basis of relative emission rates provided (see Table 5-5, Aerocomp, Inc. 1984).

h   Modeled on the basis of the following: stack height = 55 m (180.4 ft), stack diameter = 6 m (19.7 ft), velocity = 12 m/s (39.4 ft/s), and temperature = 393 K (247.7°F). Values derived from the original source on the basis of relative emission rates provided (see Table 5-5, Aerocomp, Inc. 1984).

About a dozen other thermal processes have been described in the literature. Experiments utilizing fluidized bed pyrolysis have been conducted on Utah tar sands at the University of Utah (Marchant and Westhoff 1985; Speight 1997).

Table B-7 provides available data describing potential impact-producing factors that could be associated with a surface retort facility. These data were derived from information published by Daniels et al. (1981) on the basis of a proposed 20,000-bbl/day-capacity plant designed for the recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The proposed retort facility was a Lurgi-Ruhrgas retort. The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah. The table presents the original numbers estimated for the McKittrick project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

B.6 UPGRADING

Upgrading recovers the light components from the recovered bitumen and changes the heavy components into synthetic crude oil. By-products, which can be used directly or as raw materials for other processes, are also produced. Bitumen has a higher carbon-to-hydrogen ratio than crude oil. Some upgrading processes remove carbon (e.g., a coking operation) and others add hydrogen (e.g., a hydrogenation that converts unsaturated hydrocarbons in the saturated analogs) to reduce this ratio. Upgrading also decreases the specific gravity (density) of the synthetic crude oil to a level suitable for a refinery feedstock. Although there are variations between different production operations, four main processes are used to upgrade bitumen:

1
2

**TABLE B-7 Potential Impact-Producing Factors Associated with a
Surface Retort Facility**

Impact-Producing Factor[a]	Production Capacity (bbl/day syncrude)[b,c]			
	20,000	25,000	50,000	100,000
Total land disturbance (acres)	2,600	3,250	6,500	13,000
Water use (bbl/day)[d]	11,950	14,940	29,880	59,760
Noise (dBA at 500 ft)	73–88	–[e]	–	–
Air emissions (tons/yr)				
Retort[f]				
TSP	954	1,192	2,384	4,768
SO_x	1,002	1,253	2,506	5,011
NO_x	393	492	983	1,966
Fuel burning equipment[g]				
TSP	21	26	52	104
SO_x	24	30	61	122
NO_x	104	131	261	522
CO	17	22	44	87
THC	3	4	9	17
Storage tanks[h]				
THC	28	35	70	140
Valves, pumps, compressors[i]				
THC	3	4	9	17

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; THC = total hydrocarbons (includes methane and photochemically nonreactive compounds); TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter).

[b] Data derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Approximately 100% of the process water would need to be fresh water (Daniels et al. 1981).

[e] A dash indicates noise level not calculated.

[f] These data are based upon a Lurgi-Ruhrgas retort operating with a 97% efficient lime injection and scrubbing system to control SO_x emissions and a 99.5% efficient electrostatic precipitator to control TSP emissions. These data were modeled on the basis of the following: stack height = 76 m (249.3 ft), volume = 193.4 m^3/s (2,081.7 ft^3/s), and temperature = 88°C (190.4°F). The particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

Footnotes continued on next page.

TABLE B-7 (Cont.)

g   The fuel burning equipment includes a distillation furnace, hydrogen plant, and hydrogenation unit and includes a 50% efficient ammonia injection system to control NO_x emissions. These data were modeled on the basis of the following: stack height = 76 m (249.3 ft), volume = 22 m^3/s (236.8 ft^3/s), and temperature = 88°C (500°F). The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

h   Equipped with a double-sealed floating roof.

i   Assumes equipment is subjected to a strict maintenance program.

coking (thermal conversion), catalytic conversion, distillation (fractionation), and hydrotreating (Speight 1990, 1997; Meyer 1995; Oil Sands Discovery Center 2006b).

The recovery process has a determining influence on the ancillary processes associated with upgrading. If combustion recovery were used, the viscosity of the bitumen might need to be reduced prior to upgrading. If a steam, hot water, or hot gas injection were used, the injected fluids would probably need to be separated from the recovered bitumen/fluid mixture. In addition, the viscosity of the bitumen might need to be reduced. Similarly, if solvent recovery were used, the solvent and bitumen would need to be separated and the viscosity of the bitumen might need to be reduced (BLM 1984).

Limited data are available to describe the potential impact-producing factors that could be associated strictly with upgrading processes; usually, the data are provided for an entire plant, including extraction and upgrading facilities. Table B-8 provides data describing potential impact-producing factors that could be associated with the upgrading facilities used for processing oil shale—specifically, The Oil Shale Corporation (TOSCO) II aboveground retort facility. Given that kerogen oil (raw shale oil) derived from oil shale requires more extensive upgrading than bitumen recovered from tar sands, these data are likely to result in conservative overestimates of potential impacts. These data were derived from information published by the DOE (1983) on the basis of a 47,000-bbl/day syncrude facility, including hydrogenation and hydrotreating units.

B.6.1 Coking (Thermal Conversion)

The molecules in recovered bitumen must be reduced in average molecular weight. If heated to high temperatures, long, heavy hydrocarbon molecules break apart into shorter, lighter molecules. This process is called cracking and proceeds faster at higher temperatures (Meyer 1995; Oil Sands Discovery Center 2006c). There are two types of coking: delayed

1
2

TABLE B-8 Potential Impact-Producing Factors Associated with Upgrading Facilities

Impact-Producing Factor[a]	Production Capacity (bbl/day syncrude)[b,c]			
	25,000	47,000	50,000	100,000
Water use (bbl/day)[d]	481,910	906,000	963,830	1,927,660
Air emissions (tons/yr)				
Particulates	31	58	62	123
SO_x[e]	271	510	542	1,085
NO_x	221	416	442	885
CO	27	51	54	108
Hydrocarbons	5	9	10	19

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides.

[b] Data derived from DOE (1983) for a proposed 47,000-bbl/day-capacity TOSCO II aboveground retort (indirect mode) for production of syncrude from oil shale. Numbers for larger and smaller production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Represents evaporative losses from the coker unit.

[e] Includes emissions from tail gas incinerator.

3
4
5 coking and fluid coking. Suncor uses delayed coking, and Syncrude uses fluid coking in its
6 Athabasca operations.
7
8   Delayed coking is a batch process. Recovered bitumen is heated to 925°F and pumped
9 into one side of a double-sided coker where it cracks into vapor and coke. The vapors escape
10 from the vessel for condensation and further processing, and the coke remains behind. In about
11 12 hours, the first side is full of coke and the cracking operation shifts to the other side. The solid
12 coke is cut out by use of a water drill (Oil Sands Discovery Center 2006b).
13
14   Fluid coking is a continuous process. Bitumen is heated to 925°F (500°C) and blown into
15 a vessel containing small spheres of coke suspended in an upward flow of steam. The large
16 molecules in the bitumen are cracked, and the resulting smaller molecules are carried out of the
17 top of the vessel as a vapor for condensation and further processing. The remaining coke
18 agglomerates with the coke spheres, which eventually become large enough to settle to the
19 bottom of the vessel from which they are removed. At the Syncrude operation, the process
20 recovers about 86 bbl of synthetic crude for every 100 bbl of recovered bitumen. In another
21 variation, the heated bitumen is sprayed into the entire height and circumference of the vessel
22 and cracks into a gas that is removed from the top of the vessel and a fine coke powder that is
23 removed from the bottom (Meyer 1995; Oil Sands Discovery Center 2006b).
24

1   Both fluid and delayed coking produce coke, distillate oils, and light gases. Upwards of
2   75% of the bitumen is converted to liquids, with fluid coking giving 1 to 5% more than delayed
3   coking. Most of the coke is used to produce heat for the upgrading operations. More is produced
4   than is needed and is stockpiled for storage. Sulfur occurs throughout the distillates from both
5   processes. Nitrogen occurs in all fractions but is concentrated in the higher boiling point
6   fractions. Naphtha and gas oil require the addition of hydrogen to be suitable as refinery feeds
7   (Speight 1997; Oil Sands Discovery Center 2006b).
8
9
10 **B.6.2 Catalytic Conversion**
11
12   Catalytic conversion is really a thermal conversion enhanced by using catalysts. Catalysts
13 help chemical reactions occur but are not themselves chemically changed by the reactions. For a
14 catalyst to be effective, the hydrocarbon molecules in the bitumen must contact the so-called
15 active sites on the catalyst. When large hydrocarbon molecules contact the active sites, they
16 crack into smaller molecules. The catalyst also impedes the progress of larger hydrocarbon
17 molecules so that they can continue to crack into smaller pieces. In hydroprocessing, hydrogen is
18 added to the process to improve the carbon-to-hydrogen ratio (Oil Sands Discovery
19 Center 2006b).
20
21
22 **B.6.3 Distillation (Fractionation)**
23
24   Distillation is a very common refinery process. The functioning of a distillation tower
25 depends on the fact that different substances boil at different temperatures. The tower is
26 essentially kept hotter at the bottom and cooler at the top. Vapors collected from the coker are
27 introduced at the bottom and rise up through the tower. Heavier hydrocarbons with higher
28 boiling points condense near the bottom of the tower. Lighter hydrocarbons with lower boiling
29 points move upward and condense at different levels depending on their boiling points. The
30 condensed liquids are removed from the tower (Oil Sands Discovery Center 2006b).
31
32   An efficiency gain is realized in processing bitumen if the output of the coker is separated
33 into several streams for additional processing. In particular, the naphtha component requires
34 special processing. At Suncor, the coker distillate is distilled into three fractions: naphtha,
35 kerosene, and gas oil. At Syncrude, the coker distillate is distilled into two fractions: naphtha and
36 mixed gas oil. The products of additional processing, including hydrotreating, are blended to
37 produce synthetic crude oil (Speight 1997).
38
39
40 **B.6.4 Hydrotreating**
41
42   Hydrotreating is used on the gas oils, kerosene, and naphtha resulting from the upgrading
43 of bitumen. It is one of the most commonly used chemical processes for adding hydrogen to
44 organic molecules. In hydrotreating, the feedstock is mixed with excess hydrogen at high
45 pressure and temperatures of 300 to 400°C (570 to 750°F) in the presence of catalysts. The
46 process can also remove sulfur, nitrogen, and metals as well as undesirable organics from the

1   feedstock. The addition of hydrogen also helps stabilize the produced synthetic crude so that its
2   chemical composition does not change in transit between the syncrude plant and the refinery. In
3   the production of synthetic crude oil, the gases from hydrotreating (all of which are typically
4   flammable) are usually desulfurized and used as fuels on-site (Meyer 1995; Speight 1997;
5   Oil Sands Discovery Center 2006b).
6
7
8   **B.6.5 Other Upgrading Processes**
9
10   Hydrocracking is an upgrading process that cracks the bitumen in the presence of
11   hydrogen and produces higher liquid yields than coking (up to 104 bbl of synthetic fuel per
12   100 bbl of raw bitumen) because of the uptake of hydrogen. Products from hydrocracking have
13   lower contents of sulfur- and nitrogen-containing compounds than products from coking. Despite
14   the need to consume hydrogen and operate at high pressures, hydrocracking has been chosen for
15   use in two projects in Canada (Meyer 1995; Speight 1997).
16
17   In partial coking, the froth from the hot water recovery process is distilled at atmospheric
18   pressure, thereby removing water and minerals.
19
20   Flexicoking uses a gasifier to gasify excess solid coke with a mixture of gas and air. The
21   product is a low-heating-value gas that can be used on-site. This process produces a heavy pitch
22   rather than coke as a by-product by using steam stripping in a delayed coking process. The yield
23   of liquids is also increased.
24
25   The Alberta Oil Sands Technology and Research Authority Taciuk Processor
26   simultaneously extracts and upgrades the bitumen from oil sands to produce a distillate oil
27   (Meyer 1995). Heat alone is used to separate bitumen from sand, crack it, and drive off the
28   hydrocarbons. Much of the heat for the process is obtained from the separated sand, which
29   contains residual coke. The sand-coke is burned, and the heated sand is used to preheat
30   unprocessed oil sands and then discarded. The Taciuk process has several advantages over the
31   combination recovery-upgrading procedure described above. These include increased product
32   yield, a simplified process flow, reduction of bitumen losses to tailings, elimination of the need
33   for tailings ponds, improvement in energy efficiency compared with the hot water extraction
34   process, and elimination of requirements for chemical and other additives.
35
36
37   **B.7 REFERENCES**
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13   **ATTACHMENT B1:**
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15   **ANTICIPATED REFINERY MARKET RESPONSE**
16   **TO FUTURE TAR SANDS PRODUCTION**
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1   **ATTACHMENT B1:**
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3   **ANTICIPATED REFINERY MARKET RESPONSE**
4   **TO FUTURE TAR SANDS PRODUCTION**
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6
7   **1 INTRODUCTION**
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9
10   As noted in the discussion in Attachment A1 to Appendix A regarding refinery market
11   response to future oil shale production, crude feedstocks, regardless of their provenance, all
12   compete for acceptance into the U.S. refinery market based on a number of factors. These
13   include value factors of the feedstock itself (i.e., critical chemical and physical parameters of the
14   feedstock), reliability and consistency of supply, the logistics of transporting the feedstocks from
15   points of recovery or generation to refining facilities, the extent to which existing refinery
16   processing configurations align with feedstock parameters and their processing demands, and
17   how efficiently those feedstocks can be converted to products currently in high demand.
18   Collectively, all such factors contribute to a "refining margin" that is unique for every refinery
19   and that is constantly changing on the basis of the availability of crude feedstocks as well as
20   changing market demands for refinery products (e.g., distillate fuels, feedstock intermediates
21   delivered to other refineries for further processing, and petrochemical feedstocks). While oil
22   shale and tar sands are fundamentally different resources with respect to their depositional
23   environments, their chemical compositions, their extraction and production technologies, and
24   their marketable products, many of the same factors influencing penetration of oil shale–derived
25   crude feedstocks into the refining market can be seen to be in effect for tar sands–derived
26   feedstocks.
27
28   Attachment A1 of Appendix A of this PEIS gives an overview of the U.S. refinery
29   market, including discussions of critical parameters in the crude oil refinery process, market
30   responses to feedstock value parameters, refinery utilization factors, current refinery capacity,
31   the Petroleum Administration for Defense District (PADD) system, current crude sources
32   (including Canadian syncrude production), and other possible market drivers. This brief
33   overview discusses how tar sands–derived crude feedstocks might be incorporated into the
34   U.S. refinery market and how the availability of these new crude feedstocks may influence
35   decisions regarding construction, expansion, or reconfiguration of processing capabilities.
36
37   In a manner very similar to the anticipated market development pathways for oil
38   shale–derived crude feedstocks, the following factors predominate in supporting refinery market
39   adjustments to tar sands–derived crude feedstock:
40
41   The investment into and expansion of refining capacity are solely determined by
42   the investor's long-term expectation of refining margins. Only those crude
43   feedstock sources that can demonstrate long-term availability and consistent
44   quality factors are likely to be considered as drivers for refinery processing
45   capacity expansions or crude feedstock displacements.
46

1   •   New crude feedstock sources displace sources in existing markets based on
2   how well their quality parameters align with existing or expanding refining
3   capability; the market will take proportionately longer to accept new sources
4   with quality factors substantially different from existing or alternatively
5   available sources; conversely, refineries will more readily consider an
6   expansion in capacity within their current processing configurations if new
7   feedstock sources become available and can be seen to result in satisfactory
8   refining margins.
9

10   •   Incremental expansion at existing facilities is the expected primary way in
11   which tar sands−derived crude feedstock will be introduced into the refinery
12   market. Given the modest ultimate production levels forecasted both
13   collectively and at individual facilities, there will be little to no impetus to
14   build new refineries solely in response to this U.S. tar sands−derived
15   feedstock's newly established availability.
16

17   •   Only high-volume feedstock streams of proven reliability and consistency will
18   precipitate major refinery expansions and/or displacements, or major
19   expansions and/or construction of long-distance pipelines to link the feedstock
20   to distant refineries.
21

22   •   Pipelines do not drive refinery market investments. Pipeline operators react to
23   emerging markets and provide transportation linkage between the source and
24   refiner.
25

26   •   Intuitively, domestic sources of crude feedstocks are more desirable than
27   foreign sources simply because of their inherently more secure status.
28   However, to retain their advantage, such domestic sources must also compare
29   favorably with imported feedstocks with respect to overall product yield and
30   other quality parameters (e.g., contaminant and acid content).
31
32

2 IMPORTANT CHARACTERISTICS OF TAR SANDS RESOURCES AND RESULTING MARKETABLE PRODUCTS

35
36
37   Production of crude feedstock and/or asphalt from many facilities producing from tar sands
38 deposits in Utah may approach a total of about 300,000 bbl/day over the next 20 years
39 (2007−2027).[1] It is anticipated that most of the tar sands−derived feedstocks will be crude
40 feedstock, with a smaller portion being produced as asphalt. Table 1 provides a comparison of
41 some critical chemical and physical parameters of various tar sands deposits within selected
42 Special Tar Sand Areas (STSAs) in Utah.

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[1]   To facilitate discussion of potential effects of tar sands development, the BLM assumed a commercial
production level of approximately 300,000 bbl/day.

1   **TABLE 1 Critical Chemical and Physical Properties of Selected Tar Sands Deposits**

PROPERTIES OF SELECT UTAH TAR-SAND BITUMENS

PROPERTY	Tar Sand Triangle	P.R. Spring Rainbow I	P.R. Spring Rainbow II	P.R. Spring South	Sunnyside	Whiterocks	Asphalt Ridge
Bitumen content, wt%	4.5	14.1	8.5	6.5	8.5	8	10.9
Specific gravity	1.01	1.0157	0.9872	1.0083	1.0328	0.9979	0.97
Gravity, °API	8.6	7.8	11.8	8.8	5.5	10.3	14.4
Conradson carbon, wt%	16.7	14	17.4	24	14.8	13	ND
Ash, wt%	0.2	3.3	1.4	1.9	2.4	0.8	0.04
Pour point, °F	94	210	320	320	ND	ND	ND
Viscosity, cps	42638	8269	2900	7031	7373	29245	2015
Simulated distillation							
IBP, °F	316	279	316	308	ND	307	ND
Volatility, wt%	34.4	39.9	22.8	14.3	32.4	22.1	ND
IBP-400 °F, wt5	0.7	1.3	0.5	0.7	0.9	0.9	ND
400-650 °F	7.6	5.1	2.2	1.3	7.3	3.3	ND
650-1000 °F	26.2	25.6	20.1	12.3	24	18.8	ND
>1000 °F residue, wt%	65.61	68.1	77.2	85.1	67.6	77.9	ND
Elemental Analysis							
C, wt%	84.3	84.7	81.41	81.7	83.3	85	85.2
H, wt%	10.3	11.2	10.3	9.3	10.8	11.4	11.7
N, wt%	0.4	1.3	1.4	1.4	0.7	1.3	1
S, wt%	4	0.5	0.4	0.4	0.6	0.4	0.6
O, wt%	1	1.8	6.3	7.2	4.4	1.6	1.1
Atomic H/C ratio	1.47	1.6	1.51	1.36	1.56	1.61	1.65
M$_r$, g/mol	571	702	1381	1561	1024	ND	668
Gradient elution chromatography							
Saturates, wt%	13.3	9.5	15.8	4.1	13.2	15.3	10
MNA/DNA oils, wt%	9.7	10.2	3.5	5.3	21	8.5	11.4
PNA oils, wt%	11.7	11.4	9	0.9	5.9	11.9	4.4
Soft resins, wt%	25.9	13.9	5.8	4	13.9	16.7	18.4
Hard resins, wt%	1.9	1.1	2.3	1.8	5.6	2.6	1.2
Polar resins, wt%	3.5	2	3.6	1.1	1.7	2.7	3.7
Asphaltenes, wt%	30.6	31.3	35.9	55.7	29.8	31.2	39.9
Non-eluted asphaltenes, wt%	3.5	20.6	24.1	27.1	8.9	11.1	11.1

Source: On-line poster by Steve Schamel and John Baza

2
3
4   Source: Gwynn (2006).
5
6
7   Although it can be anticipated that development of each of the STSA deposits will follow
8   very different cost and logistical schedules to generate marketable product, the refining market is
9   generally insensitive to resource development costs and logistical demands and impediments.
10   Therefore, for the purposes of this analysis, all tar sands developers are considered to be in the
11   same starting position with respect to finding markets for their products, irrespective of the
12   overall costs each developer has incurred in getting to that point.
13
14   Although the cost of resource development is outside the scope of determining the
15   competitiveness of the resulting products to the refinery market, critical chemical and physical
16   parameters of those products are not. Thus, for example, the Sunnyside deposit that would

1   produce raw bitumen with an American Petroleum Institute (API) gravity[2] of 5.5° puts the
2   developer at a distinct disadvantage compared with developers of other deposits whose raw
3   bitumen API gravities are higher, since the Sunnyside developer would need to invest greater
4   effort to improve the gravity of his product for economical pipeline transport. However, as can
5   be seen from Table 1, API gravities for any U.S. tar sands bitumen can range from a low of
6   5.5° to a high of 14.4°. Consequently, even the bitumen with the highest API gravity is still not
7   acceptable for pipeline transport, suggesting that all developers would be faced with the
8   requirement to improve on the quality of the raw bitumen they recovered before having any
9   realistic opportunity of finding both a refining market and an economical way of getting their
10 product to that market.
11
12   Likewise, developers whose raw bitumen has the lowest percentages of refining catalysts-
13 fouling contaminants, such as sulfur and nitrogen, would have an initial competitive edge over
14 sources where the amounts of these contaminants are higher. In addition to threatening the safe
15 operation of refinery processing units, adding to the cost of operation by reducing the life of
16 expensive catalysts and adding to processing unit downtime for catalyst replacement, the
17 presence of both nitrogen and sulfur contaminants may cause a refinery to incur heavier
18 regulatory burdens. Severe limitations could be placed on resulting processing emissions, which
19 would require significant investments in pollution control devices before necessary operating
20 permits could be secured. Even without emission limitations, the recently promulgated standards
21 for low-sulfur diesel fuels for on-road vehicles further increases the costs of processing by
22 requiring additional expensive sulfur removal steps to meet product specifications. Premature
23 catalyst replacements, increased regulatory controls, and more rigorous product specifications
24 can each severely impact refining margins and thus reduce the attractiveness of the feedstock. To
25 remain competitive with intrinsically higher quality feedstocks, purveyors of high-sulfur, high-
26 nitrogen, and low API gravity feedstocks must consider discounting or, alternatively, carrying
27 the costs themselves of improving these parameters before offering their product to refineries.
28
29   Crude feedstock quality is among the most critical of factors affecting refinery market
30 penetration. Because there has been very little commercial development of U.S. tar sands
31 deposits, there is virtually no empirical evidence on which to base any presumptions of the
32 quality factors for U.S. tar sands–derived products; however, irrespective of the recovery
33 technology employed, recovery of bitumen from its natural setting is simply a physical
34 separation process and is not expected to substantially change its chemical composition.
35 Consequently, it is safe to assume that the quality factors displayed by bitumen in its natural
36 setting will survive virtually unchanged throughout any separation processes (see Table 1).
37
38   Tar sands deposits in Canada are fundamentally different from tar sands in the
39 United States. The presence of a free water sheath surrounding the inorganic sand and separating
40 it from the bitumen in Canadian deposits (known as "water-wet tar sand") facilitates the
41 separation of the bitumen from the sand using relatively inexpensive and highly effective
42 (but water-intensive) separation technologies. Those same technologies, while technically

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2   API gravity is an arbitrary scale for expressing the specific gravity or density of liquid petroleum products.
    Devised by the API and the National Bureau of Standards, API gravity is expressed as degrees API. API
    gravities are the inverse of specific gravity. Thus, heavier viscous petroleum liquids have the lower API values.

1   available to developers of U.S. tar sands, will not produce the same efficiencies of separation as
2   they do for Canadian developers and would be executed at a higher cost in U.S. development or
3   not at all because of the unavailability of the required volumes of water. Amended technologies
4   to those practiced in Canada, as well as alternative technologies, are nonetheless available for
5   U.S. tar sands, although at higher overall costs and/or reduced recovery efficiencies. As noted
6   above, however, such development costs are not of particular concern to refiners; decisions
7   regarding acceptance of new feedstocks are based on the quality, availability, and cost of the
8   feedstocks and the refining margins of the resulting products, and disregard the difficulty or
9   efficiency of resource recovery. In this sense, raw bitumen recovered from U.S. deposits can be
10 expected to be generally equivalent to Canadian bitumen in critical quality factors, despite
11 expected higher recovery costs. Likewise, synthetic crude resulting from upgrading of U.S. tar
12 sands–derived bitumen is expected to be generally equivalent to synthetic crude that results from
13 upgrading Canadian-derived bitumen to an equivalent extent, again, costs notwithstanding.
14 Consequently, those same refineries that now are configured to receive significant quantities of
15 Canadian syncrude or raw bitumen can be expected to find U.S. tar sands–derived feedstocks
16 equally attractive from a quality perspective. Other factors of attractiveness, such as reliability
17 and consistency of supply over time, have not been established for U.S. tar sands–derived
18 feedstocks, however, and are not likely to be equivalent to Canadian analogs, based on the
19 relative magnitudes, accessibility, and quality of the respective tar sands resources and the
20 maturity of the Canadian tar sands industry and its supporting transportation infrastructures.
21
22
23   **3 ISSUES ASSOCIATED WITH UPGRADING**
24
25
26   As discussed above, all tar sands deposits are not equal with respect to the products they
27 might potentially offer to refineries. Obtaining equality by improving upon or eliminating
28 unattractive chemical and physical properties of the raw bitumen involves upgrading of the raw
29 bitumen by either removing carbon (coking reactions) or adding hydrogen (hydrogenation)
30 Reacting bitumen with hydrogen results in two distinct types of reactions: hydrocracking (adding
31 hydrogen to complex, unsaturated molecules to make smaller, more desirable saturated
32 hydrocarbons) and hydrotreating (converting sulfur- and nitrogen-bearing constituents to
33 hydrogen sulfide and ammonia, respectively, both of which can be subsequently easily removed
34 from the product stream). Upgrading can be performed to whatever extent is desired, yielding
35 ever-increasing quality of resulting products with proportionally increasing costs. Upgraded
36 products are generally referred to as synthetic crude, regardless of the extent of upgrading. Even
37 modest degrees of upgrading would require a substantial investment in resources (e.g., electric
38 power, natural gas, and water), expensive reactants such as hydrogen, processing equipment, and
39 related infrastructure. Developers of tar sands deposits that exist in relatively remote, arid areas
40 with limited access to required resources and other logistical constraints would be at a
41 disadvantage in pursuing this strategy. Consequently, any upgrading performed at the tar sands
42 development site would be expensive and impossible without significant investment in
43 supporting infrastructures. Nonetheless, the analyses in this PEIS anticipate that some modest
44 amount of upgrading of raw bitumen would occur at U.S. tar sands developments.
45

1   An additional strategic option exists that is unique to tar sands. The raw bitumen itself is
2 a legitimate constituent of conventional crude oil and, without further chemical alteration, can
3 serve as a feedstock for properly configured refineries. Some logistical impediments still exist
4 for this development path, however. The relatively low API gravity of raw bitumen (see Table 1)
5 preempts its transport by pipeline. However, diluents such as raw naphtha, raw gas oil, or other
6 crude oil distillation condensates, any of which would be in abundance in integrated refineries,
7 can be shipped to the tar sands development and mixed with the raw bitumen to form a solution
8 (known in the industry as "dil-bit" or "dilbit") that can be transported by conventional pipeline.
9 Once arriving at the refinery, the diluent can be separated and used again for pipelining
10 subsequent batches of raw bitumen. However, dilution ratios as high as 30% by volume diluent
11 may be necessary (Brierley et al. 2006), and transporting the diluent to the mine site in requisite
12 volumes by truck would ensure that any strategy involving dilbit would be expensive.
13 Nevertheless, as will be discussed later, evolution in processing capabilities in the refining
14 industry to add greater coking capacity is compatible with this strategic option, and production
15 and shipment of diluted bitumen are already being pursued by many Canadian tar sands
16 developers. Of the more than 2.17 million bbl/day of crude feedstocks imported into the
17 United States from Canada, approximately 400,000 bbl/day consists of un-upgraded bitumen
18 (transported as dilbit), sold primarily to refineries configured to process heavy crudes.[3] Finally, a
19 smaller fraction of Canadian crude imports is transported as "Syn-dil-bit," a blend of synthetic
20 crude, distillation condensates, and bitumen. Such mixtures, however, are typically sold to
21 refineries configured to process light to medium crudes. Each of the bitumen mixtures described
22 above commands its own unique processing scheme, and major challenges remain for refiners of
23 such bitumen mixtures. Bitumen dilutions typically are assembled to meet a target API gravity of
24 20°; however, most will still contain significant volumes of residuum and have a high sulfur
25 content. By comparison, the synthetic crudes resulting from upgrading of raw bitumens would be
26 characterized by virtually no residual and relatively low sulfur content.[4] Distillates yielded in
27 their subsequent refining, however, would have high aromatic character, which would necessitate
28 greater degrees of subsequent hydrotreating to produce rigorously specified transportation fuels.
29 Further, distillate suites also would typically include relatively high volumes of polyaromatic gas
30 oil, which would reduce the yields in subsequent downstream fluid catalytic cracking (FCC)
31 units.

4 EVOLVING CRUDE FEEDSTOCK MARKETS

37   Currently, light crude (API gravity of 34° or higher) represents approximately 50% of the
38 crude oil available on the world market. Much of the availability and thus more rapid depletion
39 of light crudes are due to the Organization of Petroleum Exporting Countries (OPEC) quota
40 system. This quota on total production volumes provides incentives to OPEC producers to sell

---

[3] To facilitate import of bitumen, pipelines specifically designed to deliver diluent to Canadian tar sands mine sites
     are also now being constructed.

[4] Although synthetic crudes are typically low in overall sulfur content, the specific sulfur-bearing species that
     remain are difficult to treat. Significant effort is required to hydrotreat synthetic crude distillate fractions to meet
     the recently promulgated ultra-low-sulfur on-road diesel fuel specifications.

the higher margin light crudes. Production of light sour crude is expected to increase by 9 million bbl/day by 2015, but the production of light sweet crude is expected to increase by only 1 to 2 million bbl/day over the same period (Phillips et al. 2003). Availability of light sweet crude is expected to continue to decline as production in key areas declines. At the same time, availability of heavier synthetics and bitumen blends is increasing and is expected to reach almost 3 million bbl/day by the year 2015 (Brierley et al. 2006). Concurrently, demand for lighter distillate fuels continues to increase, and specifications for such fuels become more rigorous. Consequently, refiners throughout the country are focusing their attention on expanding their capacity for "bottom of the barrel" processing and seeking out heavier crude feedstocks, including synthetics. Traditionally, heavier crude feedstocks were converted to low-value fuel oils, asphalts, and lube stocks, with these relatively low-value products commanding severe discounting of the parent feedstock. However, reconfiguration to add coking, delayed coking, FCC, and hydrocracking capacities allows refineries to switch to heavier crude stocks and still meet market demands for lighter, more rigorously specified fuels.[5] Deep discounting of heavier crudes allows refineries to obtain amortization of their reconfiguration costs over a reasonable period while still maintaining adequate refining margins. Increased "bottom of the barrel" processing capacity is driven not only by "upstream" factors, such as crude source availability, but also by "downstream" factors such as increased markets for transportation fuels with a coincident decline in the market for heavier residuals, an increasing demand for anode-grade coke,[6] and a continued inclination by the refinery industry to meet changing processing and product demands by reconfiguring or expanding capacities at existing refineries rather than building new grass-roots crude processing capacity.

Crude feedstocks from Canadian tar sands production can be seen as significant competition for U.S. tar sands–derived synthetics and bitumen. Not only is the Canadian tar sands resource substantially larger, more contiguous, and more homogeneous than the U.S. resource, the Canadian tar sands industry is mature, and the volumes of Canadian imports are expected to grow significantly in the near term. For example, by 2015, a forecasted Canadian syncrude import volume of approximately 4.5 million bbl/day could represent as much as 28% of the U.S. refinery industry's crude consumption nationwide.[7]

Canadian imports into PADD 4 refiners, the region in which the Utah tar sands deposits are located, has increased from 2000 to 2005 by approximately 40%, as shown in Table 2. The

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[5] Phillips et al. (2003) reports that approximately 50% of the worldwide coking capacity is concentrated in the United States and totaled more than 2,000,000 bbl/day of installed capacity in 2003. In the 15 years previous to 2003, delayed coking capacity had grown by 56% in the United States, followed by hydrocracking (37%) and FCC (14%).

[6] Anode grade coke is used in aluminum smelting and generally requires a crude feedstock that is low in sulfur and low in metals but that typically commands a high price, guaranteeing high refining margins even with the purchase of more expensive crude.

[7] The Energy Information Administration (EIA) forecasts that by 2015, the total volume of crude actually consumed by all U.S. refineries will be 16.3 million bbl/day. For clarification against refinery capacities discussed earlier, assuming continuing refinery utilization rates of 93%, this volume infers 17.5 million bbl per stream day refinery distillation capacity, which can be reasonably expected to come from incremental expansions of existing facilities. EIA crude volume consumption forecasts can be downloaded from http://www.eia.doe.gov/oiaf/aeo/pdf/aeotab_11.pdf.

1   **TABLE 2 PADD 4 Crude Imports by Mode of Transportation**

Mode of Transportation	Year (1,000s of bbl/day)					
	2000	2001	2002	2003	2004	2005
Total	505	501	522	527	555	559
Pipeline	474	468	488	489	510	508
Domestic	287	263	257	253	248	247
Canadian	187	205	230	236	261	260
Trucks	31	33	34	38	45	52
Domestic	31	33	34	38	45	52
Canadian	0	50	0	0	0	0

Source: EIA (2006a).

2
3
4   majority of this was upgraded synthetic crudes. These crudes (after upgrading) are being offered
5 at prices roughly equivalent to domestic conventional crudes in the region. The attractiveness of
6 the synthetic crudes over conventional domestic crudes is based on the lack of light ends, such as
7 butane and propane, and the lack of the bottoms or residual. Both of these fractions are of less
8 value than the "middle of the barrel" transportation fuel progenitors and sometimes even below
9 the cost of the crude, thereby destroying overall value. In addition, the domestic crude in the area
10 has a higher sulfur content, which requires additional capital investment and operating expense
11 to meet low-sulfur fuel specifications.
12
13   The overall markets for residual fuel oils have diminished over time. The key remaining
14 market is heavy, relatively high-sulfur "bunker fuels" used primarily in ocean-going vessels.
15 PADD 4 refineries do not have ready access to this market, primarily because of their geographic
16 location. Therefore, there has been an incentive to import upgraded synthetic crudes, which lack
17 a residual cut. Aside from acquiring a synthetically derived crude, which lacks a bottoms or
18 residual product, it must either be sold as lower value asphalts and fuel oils or be upgraded into
19 transportation fuels. The most common process technologies in the upgrading of bottoms
20 (as found in bitumen, but not in upgraded synthetic crudes) are forms of thermal cracking called
21 cokers. They produce roughly 65% transportation fuels and 35% petroleum coke from the
22 residual portion of a full crude barrel. PADD 4 thermal cracking capacity has been relatively flat
23 since 2001 (except for normal capacity creep through normal maintenance and debottlenecking)
24 as shown in Table 3. This represents coking capacity at only 4 of the 16 PADD 4 refineries. This
25 leaves a significant portion of the market with available options to invest in this heavy upgrading
26 utilizing this new crude resource. Currently, two coker projects are under construction in
27 PADD 4, with one more announced. In addition, there is one coker being constructed adjacent to,
28 but outside PADD 4, at Borger, Texas, which is to be supplied as part of a new strategic
29 partnership between Encana and ConocoPhillips.
30
31   Because of the Canadian tar sands industry's maturity and other important circumstantial
32 factors such as resource availability, many Canadian developers have begun extensively
33 upgrading their products to eliminate problematic characteristics of earlier products and enhance

1   **TABLE 3 PADD 4 Thermal Cracking Downstream Refining Capacity**

	Year (1,000s of bbl/stream day)					
Coking Type	2001	2002	2003	2004	2005	2006
Total	45,700	45,700	46,850	47,250	47,950	48,850
Delayed	36,800	36,800	37,950	37,950	37,950	38,450
Fluid	8,900	8,900	8,900	9,300	10,000	10,400

Source: EIA (2006b).

2
3
4 more desirable characteristics without proportional increases in costs. For example,
5 Brierley et al. (2006) report that Suncor markets a light sweet crude, Suncor Oil Sands Blends A
6 (OSA), that is the product of hydrotreating the products of delayed coking performed at the
7 Suncor mine site. Suncrude Canada Ltd. markets a fully hydrogenated blend, Syncrude Sweet
8 Blend (SSB), utilizing fluidized bed coking technology. Husky Oil now operates a heavy crude
9 upgrading system consisting of a combination of ebullated-bed hydroprocessing and delayed
10 coking to produce Husky Sweet Blend (HSB). The Athabasca Oil Sands Project uses ebullated
11 bed hydroprocessing to produce Premium Albian Synthetic (PAS). Upgraded Canadian
12 synthetics display very favorable characteristics over un-upgraded bitumens, with API gravities
13 as high as 38.6° and sulfur contents as low as 0.1% by weight (Brierley et al. 2006). Light sweet
14 synthetic crudes produced at mine site upgrading facilities command a premium price on the
15 market (but still discounted relative to conventional light sweet crudes) and are comparable to
16 conventional light sweet crudes in many respects. However, because of the high aromatic
17 character of the parent bitumen, even these upgraded light sweet synthetic crudes are attractive
18 only to refineries configured specifically to handle them.
19
20   In recent years, strategic mine site upgrading decisions have not been made unilaterally
21 by Canadian developers, but, instead, are the products of extensive collaboration with individual
22 refineries. The result has been the production of synthetic feedstocks uniquely suited to a
23 particular refinery's processing capabilities and, at the same time, reconfiguration strategies
24 undertaken by the refineries to ensure full compatibility with particular synthetic crude sources.
25 The highly integrated agreements between feedstock supplier and refiner that result from such
26 collaborations are not easily overturned or displaced. However, while such one-on-one
27 collaborations can yield both increased overall efficiencies and maximum refining yields, it is
28 generally acknowledged that, as the Canadian tar sands industry continues to grow, there will be
29 an increasing need to direct synthetic crude production into a few "marker" categories in
30 consultation with major refining market centers as opposed to individual refineries, rather than
31 allow a continuing expansion in the number of "boutique feedstocks" (OSEW/SPP 2006).
32
33   Irrespective of any controls being placed on the variety of synthetic crudes being
34 developed, it will continue to be the case that Canadian tar sands developers will have much
35 greater opportunities to undertake bitumen upgrading at their mine sites than will
36 U.S. developers. The ability to upgrade at the mine site, together with purchasing agreements

1   already in place for synthetic crudes with specific properties, gives a distinct advantage to
2   Canadian developers over their U.S. counterparts in the competition for refinery market share,
3   especially in the near term.
4
5   Notwithstanding the extensive mine site upgrading discussed previously, the potential
6   refinery market for raw bitumen would be only incrementally different from the market available
7   to producers of relatively heavy conventional or synthetic crudes, including synthetic crudes
8   from tar sands. Refineries configured to accept heavier crude feedstocks, including Canadian
9   synthetics upgraded to various degrees, would be in an ideal position with respect to processing
10 capability to accept the raw bitumen. However, processing schemes are established against the
11 characteristics of a particular crude feedstock or feedstock blend, and myriad process
12 modifications are required before even modest changes in feedstock character are made. Thus,
13 simple replacements of feedstocks are not necessarily straightforward operations even if the
14 required processing units are in place. In addition to the unique processing requirements of each
15 feedstock, available processing capacity for new sources is likely to be very limited. This is
16 especially the case for refineries that have recently reconfigured to accept products from
17 Canadian sources that currently import both synthetic crude and dil-bit into the United States as
18 heavy crude feedstocks. All of the above being said, it is the case that PADD 4 refineries in
19 closest proximity to the STSAs were some of the first U.S. refineries to reconfigure to accept
20 Canadian synthetic crude. Refineries in Denver, Salt Lake City, and Cheyenne, among others,
21 have reconfigured to accept Canadian feedstocks, including raw bitumens, and would be the
22 most likely candidates for receipt of U.S. tar sands−derived crude feedstocks and/or raw
23 bitumen.
24
25   The evolution of the refining industry toward heavier feedstocks bodes well for the tar
26 sands industry in a general sense; however, there are still substantial supplies of conventional
27 crude oils of equivalent densities and qualities against which unconventional or synthetic crudes
28 such as those from tar sands must still compete. Those other conventional sources aside,
29 however, of more immediate interest and concern to U.S. tar sands developers are the current and
30 anticipated productions of Canadian tar sands−derived synthetic crudes, and especially the
31 upgraded synthetic crudes that are now being offered.
32
33
34   **5 CONCLUSIONS**
35
36
37   Bitumen and synthetic crude oil derived from Canadian tar sands represent the most
38 immediate and direct competition to U.S. tar sands−derived feedstocks for refinery market share.
39 The enormous size of the Canadian tar sands resources, the maturity of the Canadian tar sands
40 industry, the proven reliability and consistency of Canadian products, the ever expanding
41 pipeline infrastructure devoted to delivering Canadian tar sands to U.S. refineries, and the ability
42 of Canadian developers to undertake extensive upgrading of recovered bitumen at their mine
43 sites to remove unfavorable characteristics all give Canadian developers substantial market
44 advantages over U.S. developers.
45

Refineries in PADD 4 are geographically closest to each of the STSAs and have also already undertaken reconfiguration of their processing streams to accept heavy synthetic crude feedstocks, making them the most likely candidates to receive U.S. tar sands–derived feedstocks. However, Canadian imports of bitumen and synthetic crude are already being received at these refineries, and unused processing capacity is not expected to be available in any appreciable amount. It is possible that the current investment rate of transportation of Canadian crudes to alternative markets, such as the Gulf Coast (PADD 3), the West Coast (PADD 5), and international export to China and Asia could produce more competition for Canadian crudes over the long run and provide more economic room for tar sands–derived crude feedstock in PADD 4.

With a projected maximum collective production rate approaching a total of about only 300,000 bbl/day, the U.S. tar sands developments would not be large enough to single-handedly or collectively motivate significant expansions in either long-range crude pipeline transportation networks or refinery expansions, suggesting that penetration into the refinery market would be limited to refineries in the immediate vicinity of the STSAs, primarily the properly configured PADD 4 refineries. Only modest expansions of crude oil pipeline networks already in place in PADD 4 would be required to connect STSAs to PADD 4 refineries.

The market for PADD 4 refinery products is geographically constrained, thus even if additional processing capacity were to be made available by PADD 4 refinery expansions, construction and/or expansion of product pipelines to distant markets would need to occur before that additional processing capacity could be utilized.

6 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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