Appendix 8
Proved Reserves Estimation and Field Boundary Construction

A8.1 Summary

The Reserves and Production Division, Office of Oil and Gas, Energy Information Administration estimated proved reserves of crude oil, natural gas and natural gas liquids on Federal lands located in selected geologic basins of the Rocky Mountain, Appalachian, Alaska, West Coast and Southeastern United States regions. This task involved attributing reported and imputed proved reserves to individual fields, development of field boundaries, and allocating these to Federal lands. The primary results are presented in a multi-layered GIS format accompanied by metadata compliant with the Federal Geographic Data Committee Metadata Standard. Most of the methods used were modified from those developed for the EPCA Phase I and II Inventories in 2002 and 2005. Some modifications were made to accommodate geological differences between the Phase I, II and III basins, whereas other modifications represent the implementation of planned improvements. A complete methodology for the Phase I and II basins can be found in the previous Inventory reports.[1]

Data Sources and Conditioning

Data was obtained from four major sources during the project:

- Federal agencies
  - The 2004 Form EIA-23 Reserves Survey was the source for the bulk of the proved reserves estimates
  - The Federal lands boundary data were provided by the BLM.
  - EIA's US PetroSystems (USPS) production data set was a source of field names, reservoir names and 2004 production data for the States of Utah (UT), Nevada (NV), California (CA), Montana (MT), North Dakota (ND) South Dakota (SD) and Alaska (AK)
- State agencies (oil and gas regulatory agencies and geological surveys) provided well and production data either directly or via their website
- Consultant Don French of Billings, MT was the source for Nevada (NV) well location data
- Commercial vendors
  - HPDI was a source of well data for the States of UT, CA, MT, ND and SD

Several steps were involved in the data assembly and conditioning phase:

- Identification of all wells, reservoirs, and fields in the subject basins.
- Standardization of reservoir and field names to make them consistent from source to source.
- Assigning wells to fields where field names were missing from the well records.
- Identification and standardization of well types.
- Merging of the state data, commercial vendor data, and Form EIA-23 survey data.
- Identification and name editing of those fields that had wells located both inside

[1] See < http://www.blm.gov/epca >

and outside of the defined EPCA basin boundaries and fields that crossed state boundaries.

Construction of Field Boundaries

To compare the fields and their proved reserves to Federal lands it was necessary to construct a boundary or field outline for each field. Field boundaries and areas were determined by placing reasonable and appropriate buffers around individual wells, followed by their union. Buffer size was based on well spacing as determined by measuring the distances between wells in a reservoir or field. When buffering was determined on a reservoir basis the resulting boundaries for each reservoir were unioned together to create the field boundary.

Well locations for buffer determination were based on the latitude and longitude of each well's spud point or surface location (SL) for vertical wells, or, when available, the latitude and longitude of the bottom-hole location (BHL) for directional and horizontal wells, relative to those of neighboring wells. BHL data was available only for the states of AK, UT, MT, ND and SD. Of the three EPCA Phase III states which did not have BHL data (CA, WA and NV), only CA was a problem because so many wells in the Ventura Basin are drilled directionally The BHL data is available at the CA Division of Oil, Gas and Geothermal in individual well record paper records, but has not been tabulated digitally. Thus the CA field outlines and areas are based on buffered SL's and may considerably under-represent the areas for fields containing many directional or horizontal wells. WA and NV do not have any known horizontal or directionally drilled producing wells in the study areas so lack of BHL data was not an issue there.

For the States of CA, NV and WA, wells within the same field were used to determine the appropriate buffer size rather than wells within the same reservoir because reservoir information was frequently absent or incomplete. Rules were developed on the basis of the well to well distance measurements within a field (or reservoir) to determine which standard well spacing (buffer size) should be used for each field. After assigning the appropriate standard well spacing-based buffers to each field, field boundary polygons were then generated using ESRI's ArcGIS Version 9.0 software.

For vertical and directional wells, the completed production interval was considered to be represented by a point on a map. Circular buffers were created around the points representing the SL's and BHL's for vertical and directional wells, respectively. A Visual Basic application was written to automate this process. The GIS mapping software performed these main steps:

- Selection of all wells with a specific field name
- Creation of a buffer around each well in the field using the assigned standard well spacing (based on buffer distance)
- Unioning (or joining) of the buffers in each field to dissolve the inner boundaries of overlapping buffers
- Outputting of a boundary outline polygon (sometimes more than one polygon if one or more wells are located far from the other field wells) for each field

Horizontal wells were treated differently because the completed production interval of a directional well typically extends in map view from a point close to the SL to the BHL. Thus, the line connecting SL and BHL for a horizontal well was buffered for field boundary construction.

Boundary Editing and Smoothing

Portions of field boundaries that extended outside of the defined EPCA Phase III basin boundaries were clipped at the basin boundary and removed. The fraction of the total field area that was within the basin boundary was then calculated. This fraction was used to reduce the field's proved reserves to the field portion inside the basin boundary.

The outer boundaries of the resultant multi-well field polygons (outlines) often have a scalloped appearance. The polygons also often have small internal non-field "islands." Numerous alternative methods were tested during the EPCA Phase II evaluation to identify and develop an algorithm which would adequately automate smoothing of scalloped-appearing field boundaries and fill in the small "islands" while acceptably limiting the polygon area increase. The resultant smoothing algorithm, automated by a Visual Basic application in ArcGIS, was applied to all field boundary polygons. Ninety-nine percent of the resultant smoothed EPCA Phase III outlines have areas that are less than 108 percent of the unsmoothed polygon areas.

Federal Land Area and Reserves

Geographic comparison (intersection) of the smoothed field boundary polygons to the Federal lands polygons was then performed, resulting in output of a Federal lands fraction for each field.

Proved reserves estimates submitted on the 2004 Form EIA-23 survey were used in the proved reserves estimation process. For those fields in which only some of the operators reported on Form EIA-23, the minimum reserves-to-production ratio of those that had reported was multiplied by the production of non-reporting operators to impute the latter's proved reserves. To impute proved reserves for those fields in which no operator had reported on Form EIA-23, regression equations were developed from other reported observations in the basin that were used to estimate proved reserves for these typically small fields. The portion of proved reserves associated with Federal lands within the field was then computed using the Federal lands fraction. Each field was then assigned to a proved reserves size class sufficiently narrow to be useful for EPCA purposes while at the same time broad enough to ensure confidentiality of each Form EIA-23 respondent's proprietary proved reserves estimates.

For the combined Phase III basins proved Federal lands liquid reserves (crude oil plus condensate) were estimated to be 3.8 percent of total proved reserves with the percentage for individual basins ranging from 0.1 to 99.5 percent. Similarly, the combined basins' proved Federal lands gas reserves were estimated to be 2.8 percent of total proved reserves with the percentage for individual basins ranging from 0.1 to 94.7 percent. The Federal lands proved barrel of oil equivalent (BOE) reserves of the combined basins were estimated to be 3.6 percent of their total proved reserves, with the percentage for individual basins ranging from 0.1 to 99.5 percent.

Table A8-1. Targeted Basins and Their State and County Affiliations

Study Area	State	Counties
Ventura Basin	CA	Los Angeles (part), Santa Barbara (part), Ventura (part)
Eastern Oregon-Washington	WA	Adams (part), Benton (part), Chelan (part), Columbia (part), Douglas (part), Franklin (part), Grant (part), Kittilas (part), Lincoln (part), Walla Walla (part), Yakima (part)
	OR	Crook (part), Deschutes (part), Gillam (part), Grant (part), Jefferson (part), Klamath (part), Lake (part), Morrow (part), Sherman (part), Umatilla (part), Union (part), Wasco (part), Wheeler
Eastern Great Basin	NV	Clark, Elko, Eureka, Lander (part) Lincoln, Nye (part), White Pine
	UT	Beaver, Box Elder (part), Cache (part), Davis (part), Iron (part), Juab (part), Millard, Salt Lake (part), Sanpete (part), Sevier (part), Tooele, Utah (part), Wasatch (part), Washington (part), Weber (part)
	ID	Bannock (part), Cassia (part), Franklin (part), Oneida (part), Power (part)
	AZ	Mojave (part)
Williston Basin	SD	Butte (part), Corson (part), Harding, Perkins (part), Ziebach (part)
	ND	Adams, Benson (part), Billings, Bottineau, Bowman, Burke, Burleigh, Divide, Dunn, Emmons (part), Golden Valley, Grant, Hettinger, Kidder (part), McHenry, McKenzie, McLean, Mercer, Morton, Mountrail, Oliver, Pierce, Renville, Rolette, Sheridan, Sioux, Slope, Stark, Ward, Wells (part), Williams
	MT	Part of Carter, Custer, Fallon, McCone, Prairie, Valley; all of Daniels, Dawson, Richland, Roosevelt, Sheridan, Wibaux
Central Alaska- Yukon Flats	AK	Bethel (part), Dillingham (part), Fairbanks North Star (part), Lake and Peninsula (part), Matanuska-Susinta (part), Nome (part), NW Arctic (part), SE Fairbanks (part), Valdez-Cordova (part), Wade Hampton (part), Yukon-Koyukuk (part)
Northern Alaska	AK	North Slope (part)
Southern Alaska	AK	Aleutians East (part), Anchorage (part), Kenai Peninsula (part), Kodiak Island (part), Lake and Peninsula (part), Matanuska-Susinta (part), Skagway-Yakutat-Angoon (part), Valdez-Cordova (part)

A8.2 Study Areas

The study area basins targeted in the EPCA Phase III inventory and the states and counties pertinent to them are listed in Table A8-1. Boundaries for the study areas were provided by the USGS. All wells in the listed states and counties for which location information (in the form of latitude and longitude coordinates or projected coordinates) were available were selected if within the study area boundaries. Wells not located within the study area boundaries were discarded unless they were in a field that had wells located both inside and outside of the study area boundaries.

A8.3 Data Sources

Three principal sources of data were used for this study:

- Federal Agency Data
  - The 2004 Form EIA-23 Survey files which contain field-by-field proved reserves estimates and production data as reported by large operators.
  - Federal lands boundary data were provided by the BLM.

  - EIA's US PetroSystem database was the source of field and reservoir names, production data at the well for gas or the lease for crude oil, associated-dissolved gas, nonassociated gas, and condensate production in the states of AK, CA, MT, NV, ND, SD and UT.

- State Agency Data
  - Many of the oil and gas regulatory entities and the geological surveys of the producing states have official websites where tables with the following data can be downloaded and/or queried: well spud point location (latitude and longitude), field name, and well type at time of completion. Several states also have online interactive web-mapping (webmapper) applications where wells can be viewed on a map and queries about them can be made. A few states have constructed their own oil and gas field boundary or outline files; these were used, where available, to check the reasonableness of the field boundaries constructed for this project. Oil and gas production data, usually annual by well, is available to download or query for some states. Links to the websites used in this study are listed in Table A8-2.
  - Some data cannot be downloaded from the state websites even though it can be queried online and must therefore be obtained directly from a state agency. The following data were obtained from the listed state agencies (and contact person) in Table A8-3.

- Commercial Data
  - Well data tables with spud point location (latitude and longitude), field name, production, and well type at time of completion for the states of CA, MT, NV, ND, SD and UT were purchased from vendor HPDI.

A8.4 Limitations Imposed by the Available Data Sources

A variety of shortcomings and flaws in the presently available data impose unavoidable limitations either on what can be done or on the achievable level of accuracy. Chief among these are:

- Field and reservoir names are frequently non-standard, i.e., their content and/or spelling varies widely. This makes accurate automated—and often even manual—matching of field and well records across data sources difficult and sometimes not possible. While standardized field codes are assigned and supported by EIA, most field names and their spellings are assigned by state agencies. Much of the problem is rooted in the fact that, for more than two decades, many of the producing states have trimmed the resources devoted to this task, with the result that the current staff is overburdened and large backlogs exist. When reporting well or production information for a field on which the state has not yet given an official name, the field operator is free to use any name or spelling.

  An additional factor was the demise of the American Association of Petroleum Geologists' (AAPG) Committee on Statistics of Drilling, which for many years performed an essential quality control function relative to U.S. well statistics and field and reservoir names. Staffed by industry volunteers, the Committee was disbanded in 1986

Table A8-2. Links to Websites Used

AK well data	http://www.dog.dnr.state.ak.us/oil/products/data/wells/wells.htm
AK field outlines	http://www.dog.dnr.state.ak.us/oil/products/data/downloads/downloads.htm#accum
AK production	http://www.state.ak.us/local/akpages/ADMIN/ogc/publicdb.shtml
AZ production	http://www.azogcc.az.gov/
CA well data	http://www.consrv.ca.gov/dog/maps/goto_welllocation.htm
CA production	http://www.consrv.ca.gov/dog/prod_injection_db/index.htm
MT well & production	http://bogc.dnrc.state.mt.us/jdpintro.asp
MT webmapper	http://bogc.dnrc.state.mt.us/web_mapper.asp
NV well data	http://www.nbmg.unr.edu/dox/dox.htm > OF04-1
NV production	http://minerals.state.nv.us/forms/forms_ogg.htm
ND wells (subscription)	https://www.dmr.nd.gov/oilgas/subscriptionservice.asp
ND webmapper	https://www.dmr.nd.gov/oilgas/ > GIS Map server
OR well data	http://www.oregongeology.com/sub/oil/oil-gas-permits-spreadsheet07-14-06.xls
SD well data	http://www.state.sd.us/denr/DES/Mining/Oil&Gas/well_data.htm
SD Production	http://www.state.sd.us/denr/DES/Mining/Oil&Gas/producti.htm
UT well data & production	http://www.ogm.utah.gov/oilgas/DOWNLOAD/downpage.htm
UT webmapper	http://atlas.utah.gov/oilgaswells2/viewer.htm
UT field outlines	http://ogm.utah.gov/oilgas/MAP%20SEARCH/Utah_map.htm
WA well data	http://www.dnr.wa.gov/geology/energy.htm

Table A8-3. State Agencies Contacted

AK well data	Alaska Oil and Gas Conservation Commission (Steve McMains)
AK field outlines	Alaska Dept. of Natural Resources, Div. of Oil and Gas (Christine Beaty)
AZ well data	Arizona Geological Survey (Steve Rauzi)
CA field outlines	California Div. of Oil, Gas and Geothermal (Joy Arthur-Silva)
CA production	California Div. of Oil, Gas and Geothermal (Steve Fields)
MT wells, production	Montana Board of Oil & Gas (Jim Halvorson)
NV production	Nevada Division of Minerals (Christy Morris)
NV well data	Nevada Bureau of Mines & Geology (Ron Hess)
NV well locations	Don French (Consultant Geologist)
NV well locations	Jerry Hansen & Carl Shaftenaar (Consultant Geologists)
ND production data	North Dakota Industrial Commission Dept. of Mineral Resources (Jim Lindholm)
ND field outlines	North Dakota Industrial Commission Dept. of Mineral Resources (Kirby Latham)
OR well data	Oregon Dept. of Geology (Bob Houston)
SD well data, field outlines	South Dakota Dept. of Environment & Natural Resources, Oil & Gas Section (Mack McGillivray)
UT field outlines	Utah Geological Survey (Sharon Wakefield)
UT production	Utah Div. of Oil, Gas and Mining (Dan Jarvis, Vicki Dyson, Don Staley)

and its files were turned over to the American Petroleum Institute (API), which for many years maintained them absent the "in-the-field" quality control that the AAPG Committee had provided. Eventually this task was transferred to two competing commercial data vendors for continued maintenance and updating. Both recipient firms are now subsumed in IHS Energy Group.

- Related to the field name problem is the problem of unknown and/or unassigned field names. This was most prevalent in the Ventura Basin where numerous wells exist that do not have field names assigned, and was also an issue to lesser extents in UT, SD, ND and MT. Such wells were assigned field names by proximity to existing fields. Due to the much larger volume of unknown field wells in the EPCA Phase II study areas, an automated process was developed to assign field names for such wells based on the field names of nearby named-field wells. It was not necessary to use that technique in Phase III because of the smaller numbers of such wells. The process used for Phase III involved viewing of mapped well locations and the manual assignment of unknown wells to match nearby wells associated with field names. After this there were still wells that could not be assigned field names. These were assigned temporary numeric names prefaced by the letters RPD and the county name.

- Well misclassification is a perennial problem. For the most part it is caused by insufficient recursive quality control. For example, a new well may initially be classified as a wildcat well, which by definition has discovered a new field. Subsequent drilling of extension wells in this or an adjacent field may, over time connect the two adjacent fields. At this point both fields will shift to the field name of the earliest discovered of the two. This and other similar reclassifications occur frequently, but that fact often never filters backward, i.e., in this case to re-classification of the wildcat well type to extension or even development status.

- With the notable exception of fields located on the Federal OCS, the Federal government does not have access to subsurface data other than the well data available in state or vendor well files and state well log files. Because seismic data and interpretations, surface and subsurface geologic maps, and many well logs are proprietary data, in the context of the EPCA study this limits what can be done concerning the construction of field boundaries to a purely geometric approach based on the buffering of well locations around their surface spud points (or bottom hole locations for the States of AK, ND, MT and SD only).

For these reasons, the resultant field boundaries are approximations, the accuracy of which, in the absence of adequate subsurface information, depends to a greater or lesser extent from case-to-case on the professional judgment of the EIA RPD's experienced petroleum geologists and engineers. Collectively the field boundaries provided here are likely to be of sufficient accuracy for policy formulation concerning access to Federal onshore lands. In specific instances they may not be accurate enough for the application of policy and regulation.

A8.5 Process Overview

Figure A8-1 is a flow chart of the major steps followed in estimation of field-level proved reserves (on the left-hand side) and the construction of field boundaries (on the right-hand side), plus their merger into the final principal reserves product. The following discussion provides details for each of the indicated steps.

A8.6 Quality Checking and Combination of Data Sources for Each State

Owing to different oil and gas industry activity tracking histories and to non-standardization, each state's data posed unique challenges relative to assembling the most complete and accurate well data set possible for later use in constructing field boundaries. State agencies were a primary source of well data for all 8 of the producing states involved in the Phase III basins. These data were augmented with vendor or US PetroSystem well data in 6 of the 8 producing states (see Table A8-4).

A8.7 Merging of Well Data Files

For the states of NV, UT, CA, MT, ND and SD well data sets with location data were used from multiple sources (see table AA8-4). The API well number, present in the state, HPDI, and US PetroSystem well data files, was the common key for this merging process.

The merged well records that did not match with US PetroSystem Production records were most often dry holes, injection wells or storage wells. If these did not match well records in other state or vendor files for that state, they were discarded. The original database not only contained oil, gas and injection wells, but also other types of wells, such as CO2 (carbon dioxide), D&A (drilled and abandoned), dry holes, SWD (salt water disposal), STEAM, PSEUDO, SERVICE, STORAGE and WD (water disposal) wells. To create valid field boundaries only oil and gas wells were retained, whether or not they had recorded 2004 production data, excepting in Alaska where the injection wells were retained.

For the states with multiple state and/or vendor sources, the available well data sets were merged using the API number of the well (or the state permit number if the API number was not available) as the common data field. The following rules and procedures were developed and used to merge the files:

A8.7.1 Preparation of Spud Point Location Information (Well Latitude and Longitude at the Surface) and Bottom-Hole Location Information

For each state with multiple well data sources, the wells from each source were plotted on a map using the ArcGIS software. Location quality of the data sets was checked by looking for wells located far from a field's core location, wells with locations out of state, and wells located in the wrong county. This information was used to determine which source of location coordinates was the best one to use as the primary source. If location information was not available from any source the well record was deleted from the data used for field boundary construction but was retained for merger with the Form EIA-23 database and subsequent use in the determination of production and reserve volumes.

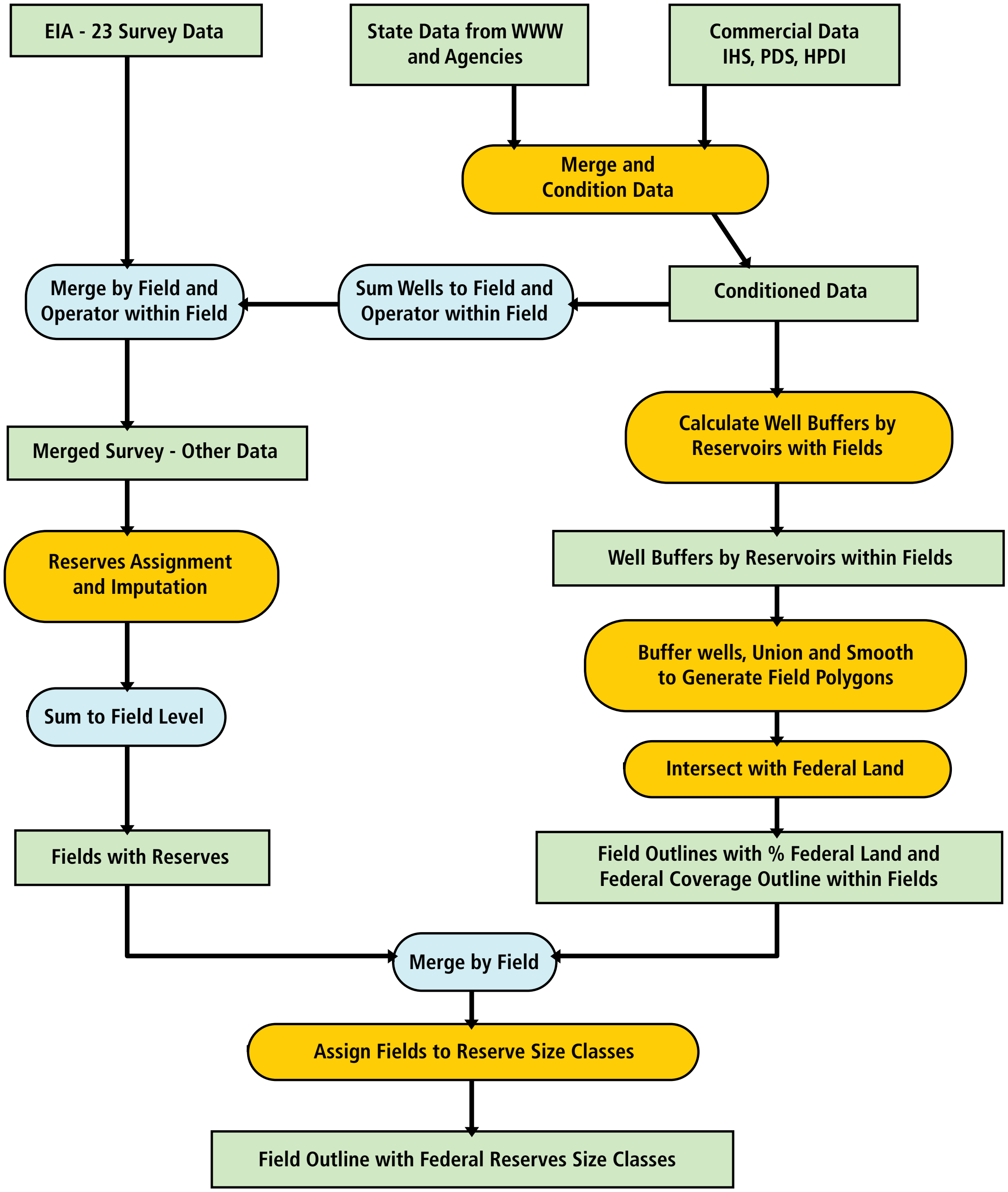

Figure A8-1. EPCA III Process Flows

Table A8-4. Well Data Sources by State Used for EPCA Phase III

Well Data Sources Used For EPCA III Evaluation					
EPCA III Area	State	Source			Comments
		Vendor	EIA	State Agency or Other Source	
North Alaska	AK			AK Oil & Gas Conservation Commission	Bottomhole locations used
South Alaska	AK			AK Oil & Gas Conservation Commission	Bottomhole locations used
Central Alaska-Yukon Flats	AK			AK Oil & Gas Conservation Commission	No producing wells
Eastern Oregon-Washington	OR			OR Department of Geology and Inustrial Minerals	No producing wells
	WA			WA Department of Natural Resources	No digital records (digitized fr. IC-75)
Eastern Great Basin	NV		USPS	Don French (Consultant)	
	UT		USPS	UT Division of Oil, Gas & Mining	Bottomhole locations used
	ID			ID Dept. of Lands, Surface & Min. Resources Bur.	No production in ID
	AZ			AZ Geological Survey	No producing wells
Ventura Basin	CA	HPDI	USPS	CA Division of Oil, Gas & Geothermal	No bottomhole locations
Williston Basin	MT		USPS	MT Board of Oil & Gas	Bottomhole locations used
	ND		USPS	ND Industrial Com, Dept. of Mineral Resources	Subscription req'd, Best BHL data
	SD		USPS	SD Dept. of Environment & Nat. Res, Oil & Gas Sect.	BHL's calculated from footage calls

For Nevada the state agency (NV Bureau of Mines and Geology) warned EIA that the calculated latitudes and longitudes for their well surface locations were not precise, having been calculated from the centers of quarter sections rather than by the more precise footage call from section line method. Several independent consultant geologists who specialize in Great Basin exploration were therefore contacted to see if they had better NV well location data. Because NV wells are all drilled in a desert environment it is possible to see cleared well pads very distinctly on aerial photography. NV well locations obtained from USPS, HPDI, the state agency, and two consultant geologists were plotted over USGS aerial photos using GIS. Although it was not possible to directly tie wells pads on the photos with specific wells being plotted, it was obvious that the well locations obtained from consultant Don French were most often in the center of the well pads on the imagery. These latitude and longitude data were therefore used for the NV wells.

Because horizontal or highly deviated wells are increasingly being drilled in the US onshore, it would be better to use the latitude and longitude of a bottom-hole location

(BHL) to locate wells rather than the surface spud-point location. Only the States of AK, ND, SD, MT and UT had sufficient BHL location data so for all other states the spud point (surface) location had to be used.

South Dakota provided its BHL data for horizontal wells in units of footage calls from the surface spud-point location. These data were converted in a GIS to the latitude and longitude of the BHL.

A8.7.2 Field and Reservoir Name Respelling and Renaming

Variation in field and reservoir names and spellings is common among the commercial data files and state sources. Names were altered as necessary to make them as consistent as possible across sources. To achieve better field boundaries it was assumed that the buffers created for wells should be calculated on a reservoir level where possible (otherwise on a field level) and that the field boundary would then be constructed by unioning of the reservoirs in the field. Reservoir names were only consistently available for the States of, UT, AK, MT, ND and SD.

Names carried on the US PetroSystem production database were used when available because they were most consistent with the names in the EIA Field Code Master List. Otherwise, names from the state files or non-US PetroSystem files were used.

A8.7.3 Missing Field Names

Well files for every state had records where the field name was missing or that contained values such as ‘UNKNOWN,’ ‘UNDESIGNATED’, ‘UNKNWN’ or ‘WILDCAT.’ For all areas the field name data field for these wells was populated manually. Wells with missing field names were plotted on a map showing the field outlines of all named fields. Unnamed field wells located within or in close proximity to a named field boundary were given the name of that field. Unnamed wells judged as too far from named field outlines to be considered part of any field were given RPD field names incorporating identification of the well’s county location was used to replace it (e.g. a new field name like “RPD_Washington_Cnty-1” was created. These wells were grouped manually into fields if their buffers intersected.

If a reservoir name was abbreviated, the full reservoir name was assigned. If a reservoir name was augmented by a layer/zone/horizon modifier (e.g. “11250 A Washita-Freder,” “11300 Washita-Freder”) the modifier was removed (e.g. all were changed to “Washita-Freder”). Most records did not contain horizon information so the zone name was used instead as the best available data for reservoir naming.

Some field names were changed based on information obtained from state data sets, state websites, and conversations with state agency personnel. A few states such as AK, UT, CA, ND and MT have developed their own spatial data files of field boundaries. These are often digitized versions of geologic outlines originally drawn by hand on paper, or in some case they represent land units and therefore have a more rectilinear look (e.g. MT and ND) than do smoothly rounded geologic field outlines (e.g. CA and UT). When these state outlines were overlaid on the field boundaries created in the present study some discrepancies were noted and investigated. This comparison resulted in additional field name edits in some instances.

A8.7.4 Identification of Well Types for Later Buffering

Deciding which wells to include in the buffering process is critically important in the construction of field boundaries. All wells where type=oil or type=gas in at least one of the source datasets were retained and classified as oil or gas. Wells which were not of type=oil or type=gas in at least one source were classified as a dry hole, a CO_2 producer, or an injection well. Following final assignment of the well type only the positively identified oil and gas wells were retained for input to the well buffering process. The exception was for injection wells located in Alaska which had a significant impact on the field outlines and were therefore retained and buffered.

Some of the state well files indistinguishably group dry holes which never produced (usually typed as "drilled and abandoned" or "D&A") with former oil or gas producing wells that are now plugged and abandoned (usually typed as "P&A"). This makes the task of separating present and former producers from wells that never produced difficult and emphasizes the importance of having good historical production data records.

A8.7.5 Merging with Production Data from Other-Sources

Well-level production data from state or vendor sources other than the USPS were merged to the well files by API number or by drilling permit number. Some states have incomplete production data. For example, WA does not have any production data for the single gas field located in the Eastern OR-WA study area.

A8.8 Construction of Well Buffers

The procedure used to generate well buffers consisted of several development and application steps. Creation of oil and gas field boundaries was accomplished using ArcGIS 9.0 software and the methodologies developed by EIA for Phase I of the EPCA inventory which are documented in detail in the EPCA Phase I report.

The basic method used to construct field boundaries was to buffer each well in a reservoir or a field with a circle. The radius of the circle was determined by analysis of the spacing pattern for the wells in each reservoir in a field if reservoir names were consistently available, or for the wells in each field if consistent reservoir names were not available. The resulting circular buffer polygons were then unioned into a single field boundary polygon set (note that if wells are far enough apart there can be more than one non-contiguous polygon per resultant single field boundary). Given the large volume of data involved and the fiscal constraints on the EPCA project, this method was used because it most effectively utilizes the available information on the different well spacing patterns present within a field and it is relatively easy to perform on a large data set.

This technique was modified for EPCA Phase III due to the abundance of horizontal wells in the study areas and, for the first time in the three EPCA phases, the availability of ample BHL data in some of the states which, along with the SL data, define the extent of a horizontal wellbore on a map. Vertical, horizontal, and directional (i.e., "slant" or

”deviated”) wells were buffered differently (see Figure A8-2). Some of the states only have vertical wells, and others have all three types. For some of the states, bottom hole location (BHL) data that is needed to define the geometry of horizontal and directional wells was not available, or there was no attribute in the data to differentiate horizontal from directional wells.

Most of the horizontal wells for the EPCA Phase III study areas are in the Williston Basin (ND, SD and MT) and Alaska. The State of North Dakota (ND Industrial Commission, Dept. of Mineral Resources, Oil and Gas Division) keeps the most detailed directional survey records which have latitude, longitude and subsea depth (feet) for numerous points between the SL and BHL. Horizontal wells in a number of ND regions were plotted on maps using GIS, with the production interval marked along the wellbore track between SL and BHL. In most cases, the production interval begins from a point just below the SL (in map view) and extends to the BHL. This observation led to the generalization that the entire distance between SL and BHL for a horizontal well should be buffered for field outline construction purposes (see Figure A8-3).

A number of different techniques were tested to build field outlines for horizontal wells: (1) buffering the SL points only, (2) buffering the BHL points only, and (3) buffering a line connecting SL and BHL. The resultant outlines from the first two techniques left too many gaps in the judgment of the EIA geologists and engineers, so the third technique was selected, resulting in a “hot dog”-shaped buffer.

In previous EPCA evaluations (EPCA Phase I and EPCA Phase II), very little BHL data was available from vendors or state agencies other than Alaska’s. For EPCA Phase III, as stated above, ND had the most complete data, plus a “hole_type” classification for each well. Thus for ND it was possible to separate and treat differently vertical wells (SL is buffered), directional wells (BHL is buffered) and horizontal wells (line between SL and BHL is buffered). The state of MT’s well data had BHL latitude and longitude data, but not the points in-between, nor identification of directional versus horizontal well type. The MT wells with BHL different from SL (either directional or horizontal) were all treated as horizontal wells because in the adjacent state of ND, horizontal well types outnumber directional well types by a ratio of 12:1. Subsequent to this analysis, the MT Board of Oil and Gas added the attribute “slant” (with values of horizontal, horizontal re-drill/re-entry, vertical, and directional) to their online oil and gas information system. The relevant wells were queried, revealing that less than 1 percent of the directional plus horizontal wells in the MT portion of the Williston Basin are directional hole types.

Only since 2001 has the state of AK maintained a data attribute that distinguishes horizontal from directional wells. Although 57 percent of the AK producing wells from 2001 to present are classified as “horizontal”, it was decided to treat all non-vertical wells in AK as directional (buffering the BHL) because so many of the pre-2001 Cook Inlet wells are directionally drilled from onshore, and to assume they are horizontal and thus buffer the entire SL to BHL line would add a lot of non-productive area between the onshore SL and the offshore BHL’s. This is also the case to a lesser extent on the North Slope.

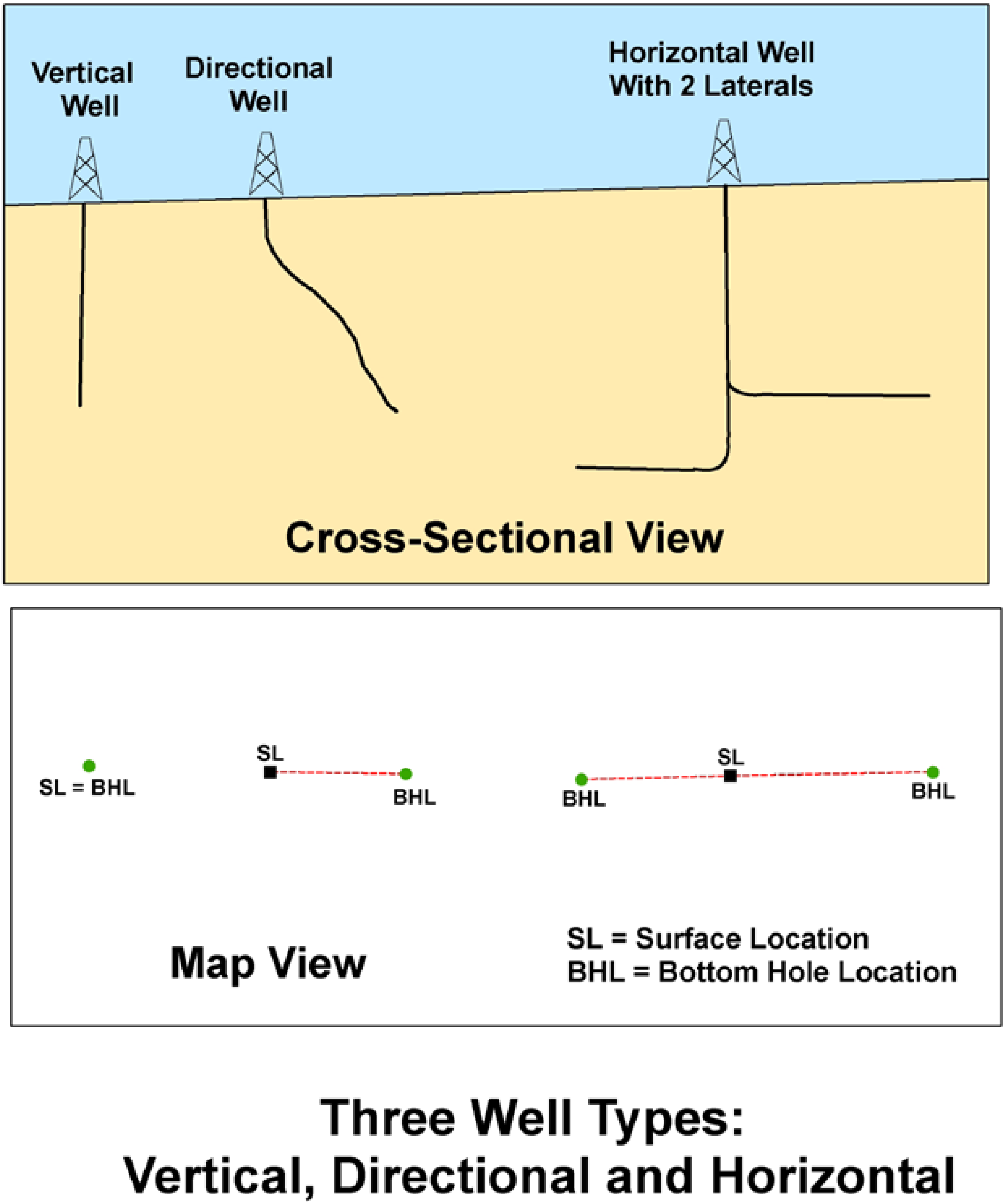

Figure A8-2. Three Well Types

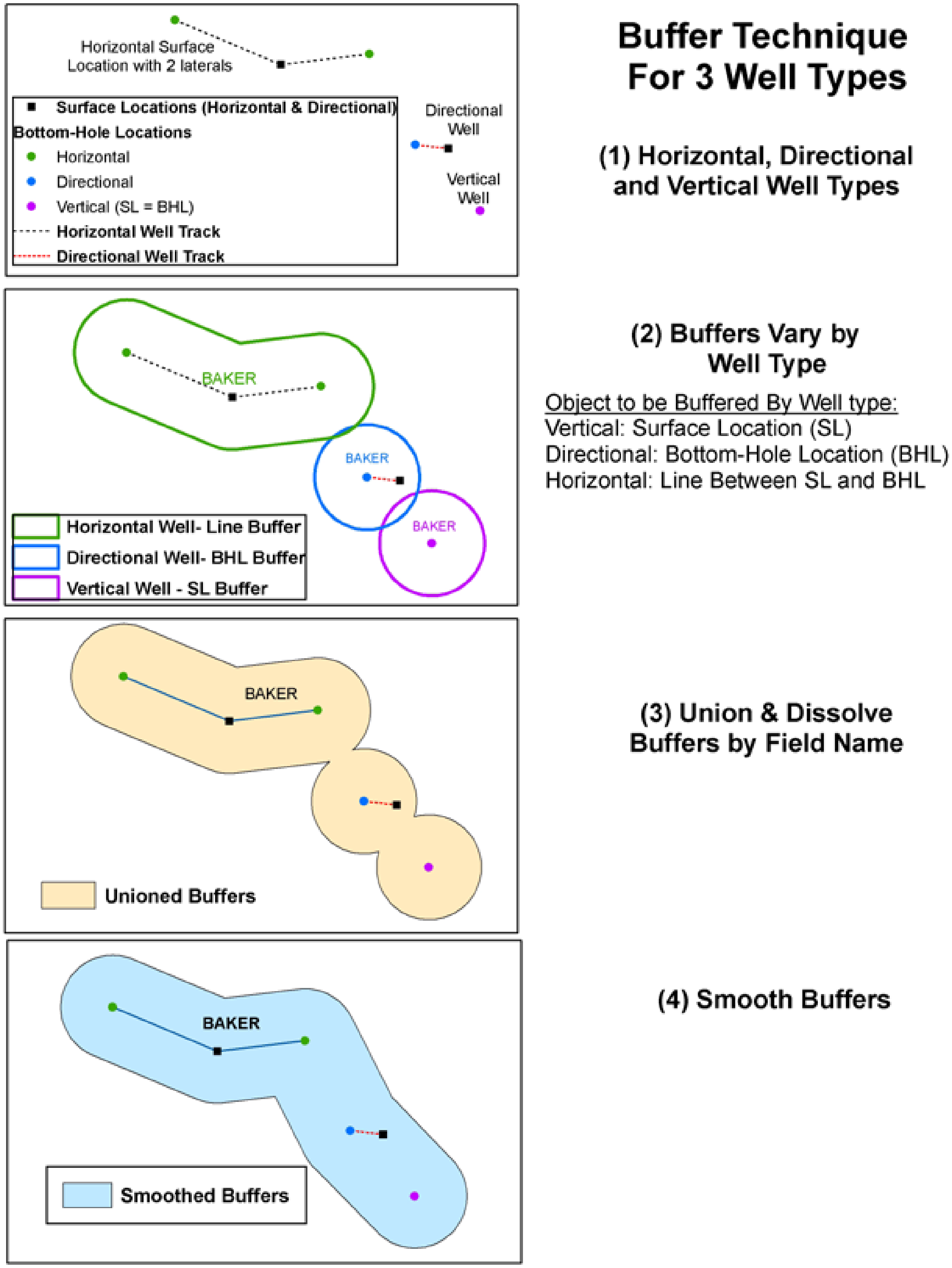

Figure A8-3. Buffer Technique for Three Well Types

A8.8.1 Determination of Nominal Well Spacing and the Assignment of Buffer Radii

An analysis of the distances between wells in a reservoir or a field, calculated from their spud point locations (or their bottom-hole locations in AK, MT, ND, UT and SD), was used to assign a standard well spacing unit to each reservoir or field. The same technique was used in Phases I and II of the EPCA project. Nearest neighbor inter-well separation distances were calculated separately for oil wells and gas wells. The upper and lower bounds of the observed spacing ranges are shown in the two left-hand columns of Table A8-5. The corresponding nominal standard well spacings (a geometric distribution) and buffer radii are shown in the two right-hand columns. The 75th percentile (P75) of the observed inter-well distance distribution was taken to be the observed inter-well distance. This statistic was selected because, as judged by the RPD project team, it yielded the best match to nominal well spacings in an extensive set of map trials done for EPCA Phase I. If the P75 distance fell within the corresponding interval shown in the two left-hand columns of the table then the corresponding nominal spacing was selected and its buffer size was initially assigned to every well in the reservoir (or field).

Table A8-5. Inter-Well Distance Ranges, Nominal Standard Well Spacings, and Buffer Radii

Inter-Well Distance		Nominal Spacing Unit (acres)	Corresponding Buffer Radius (Feet)
Lower Bound (feet)	Upper Bound (feet)		
0	277	1.25	233
277	392	2.5	330
392	555	5	467
555	785	10	660
785	1110	20	933
1110	1570	40	1320
1570	2220	80	1867
2220	3140	160	2640
3140	4440	320	3734
> 4440		640	5280

A8.8.2 Well Buffer Construction Rules

Rules for the assignment of buffers were created to handle reservoirs (or fields if no reservoir names were available) that did not, for whatever reason, readily conform to a nominal spacing. The rules are based on well types and well counts:

- For oil reservoirs the maximum spacing allowed was 160 acres, i.e. a buffer radius of 2,640 feet
- If the reservoir had between 1 and 10 oil wells or the reservoir name was ‘UNNAMED’ a spacing of 160 acres was assigned.
- If the reservoir in CA had between 1 and 10 oil wells a spacing of 20 acres was assigned.
- For gas reservoirs the maximum spacing allowed was 640 acres, i.e. a buffer radius of 5,280 feet.
- If the reservoir had only 1 gas well or the reservoir was named ‘UNNAMED’ a spacing of 320 acres was assigned.
- If a gas reservoir in MT, ND, NV, SD and UT had 3 or fewer wells a spacing of 320 acres was assigned. If it had more than 3 wells and less than 10 wells the nominal spacing unit was used per Table A8-5 up to a maximum spacing of 320 acres.
- If a gas reservoir in AK had 3 or fewer wells a spacing of 320 acres was

assigned. If it had more than 3 wells and less than 9 wells the nominal spacing unit was used per Table A8-5 up to a maximum spacing of 320 acres.

- If a gas reservoir in CA had 3 or fewer wells a spacing of 20 acres was assigned. If it had more than 3 wells and less than 10 wells the nominal spacing unit was used per Table A8-5 up to a maximum spacing of 20 acres.
- For coalbed methane wells a maximum spacing of 160 acres was assigned, i.e. a buffer radius of 2,640 feet.
- If the oil well count divided by the sum of the oil well count and the gas well count was less than or equal to 0.05 and if the oil well spacing was greater than the gas well spacing, the oil well spacing was set to the gas well spacing; otherwise, the original oil well spacing was retained.
- If the ratio of gas well count to the sum of the oil well count and the gas well count was less than or equal to 0.05 the gas well spacing was set to the oil well spacing for the field or reservoir; otherwise, the original gas well spacing was retained.
- For the ORION field in AK, 160-acre spacing (2640 ft buffer radius) was assigned in both oil and gas reservoirs.
- For the LA GOLETA field in CA, 20-acre spacing (933 ft buffer radius) was assigned to gas wells.
- For the SAN VICENTE, HOPPER CANYON and CASCADE fields in CA, 2.5-acre spacing (330 ft buffer radius) was assigned to oil wells.
- For the TORREY CANNYON, NEWHALL, EUREKA CANYON, ELWOOD SOUTH OFFSHORE, CAPITAN, SANTA CLARA AVENUE, and CURATA OFFSHORE fields of CA, 5-acre spacing (467 ft buffer radius) was assigned to oil wells.
- For the RINCON, VENTURA, PLACERITA, SHIELLS CANYON, RAMONA, DEL VALLE, BARDSDALE, SAN MIGUELITO, TIMBER CANYON, TAPO CANYON SOUTH, SANTA PAULA, NEWHALL-POTRERO, ALISO CANYON, PIRU, HOLSER, HASLEY CANYON, and SANTA SUSANA fields in CA, 10-acre spacing (660 ft buffer radius) was assigned to oil wells.
- For the BIG MOUNTIAN, SOUTH MOUNTAIN, SESPE, OJAI, MONTALVO WEST, OXNARD, SIMI, TAPO NORTH, CARPINTERIA OFFSHORE, SUMMERLAND OFFSHORE, CONCEPTION OFFSHORE, SATICOY, ELWOOD, WEST MOUNTAIN, and TEMESCAL fields in CA, 20-acre spacing (933 ft buffer radius) was assigned to oil wells.

A8.9 Construction of Field Boundaries

A SAS file containing the oil and gas well data with field name attribute “Field” (and reservoir name attribute “Reservoir” if that data was available) was imported into ArcGIS as a dBase (.dbf) file. The wells were then plotted using the latitude/longitude information in the file and converted to a geodatabase point feature class file. The coordinate system used was UTM NAD27 with the following UTM zones for each study area: Northern Alaska, Central Alaska-Yukon Flats, Southern Alaska–Zone 7, Eastern Oregon-Washington, Ventura Basin-Zone 11, Eastern Great Basin–Zone 12, and Williston Basin–Zone 14.

Before field boundary construction the following procedure was performed to ensure that all wells in the fields of interest lay entirely inside the study area boundaries. Two dbf files were made for each state, one of all wells inside the study area and another of all wells outside the study area. SAS queries were performed on those files to identify, for each state, all field names that had wells both inside and outside the study areas. These fields were then researched to determine if they were fields that actually extended across the study area boundaries or if they were geographically separate fields (not in reservoir communication) with the same name in the same state. In instances of the latter case, county names were appended to the field names (e.g. CACTUS_Morgan vs. CACTUS_Garfield) so that they would be put into different fields when the field boundaries were constructed.

Well files for each state were built that included only those wells located inside the study area/basin boundaries and all well records for fields that extended across the study area boundaries. These files were then used to construct the gross field boundary polygons. For fields that are partially outside the study area boundary, the outside portions were deleted later in the process as described below.

The Visual Basic for Applications (VBA) code implemented within ArcGIS for Phase I of the EPCA project was used to automatically create polygonal field boundaries from the buffered wells. The principal steps performed were:

- Select the "field name" attribute and "buffer distance" attribute from the well file. Select all wells with the first "field name" encountered.
- Create a buffer around each selected well using "buffer distance" (see Figure A8-4).
- Union the buffers.
- Dissolve the barriers between overlapping buffers.
- Iteratively perform the above steps for each unique "field name".
- Output a polygon feature class with one polygon (often consisting of multiple polygon rings) for each field.
- Convert to a shapefile.

Figures A8-5 and A8-6 show the buffered field boundary of a field with two reservoirs. Figure A8-5 displays buffers by reservoir: Reservoir A is composed of oil wells with 80 acre buffers while reservoir B contains oil wells with 160 acre buffers and gas wells with 640 acre buffers. The final product of the field boundary creation process with buffers for both reservoirs unioned into one polygon record is shown on Figure A8-6 (these are un-smoothed buffers).

If a state or study area had horizontal wells with BHL data, the following steps were additionally performed:

- Create a separate horizontal wells shapefile with data fields of surface latitude, surface longitude, bottom hole latitude, bottom hole longitude and buffer_distance (calculated from the BHL point). Since many horizontal wells consist of two or three lateral horizontals from a single surface location, there is one shapefile record for each lateral.
- For each lateral, create a line between SL and BHL in ArcGIS.
- Buffer each line using the buffer distance (this creates a hot dog shape rather than a circle) and union by field name.
- Merge the horizontal well buffers to the vertical/directional well buffers, unioning by field name.

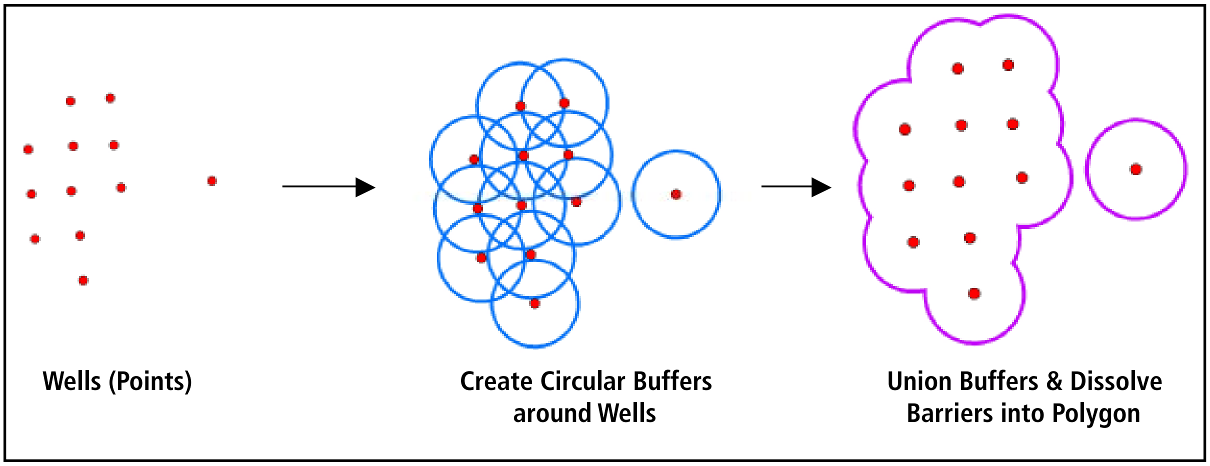

Figure A8-4. Buffering Process

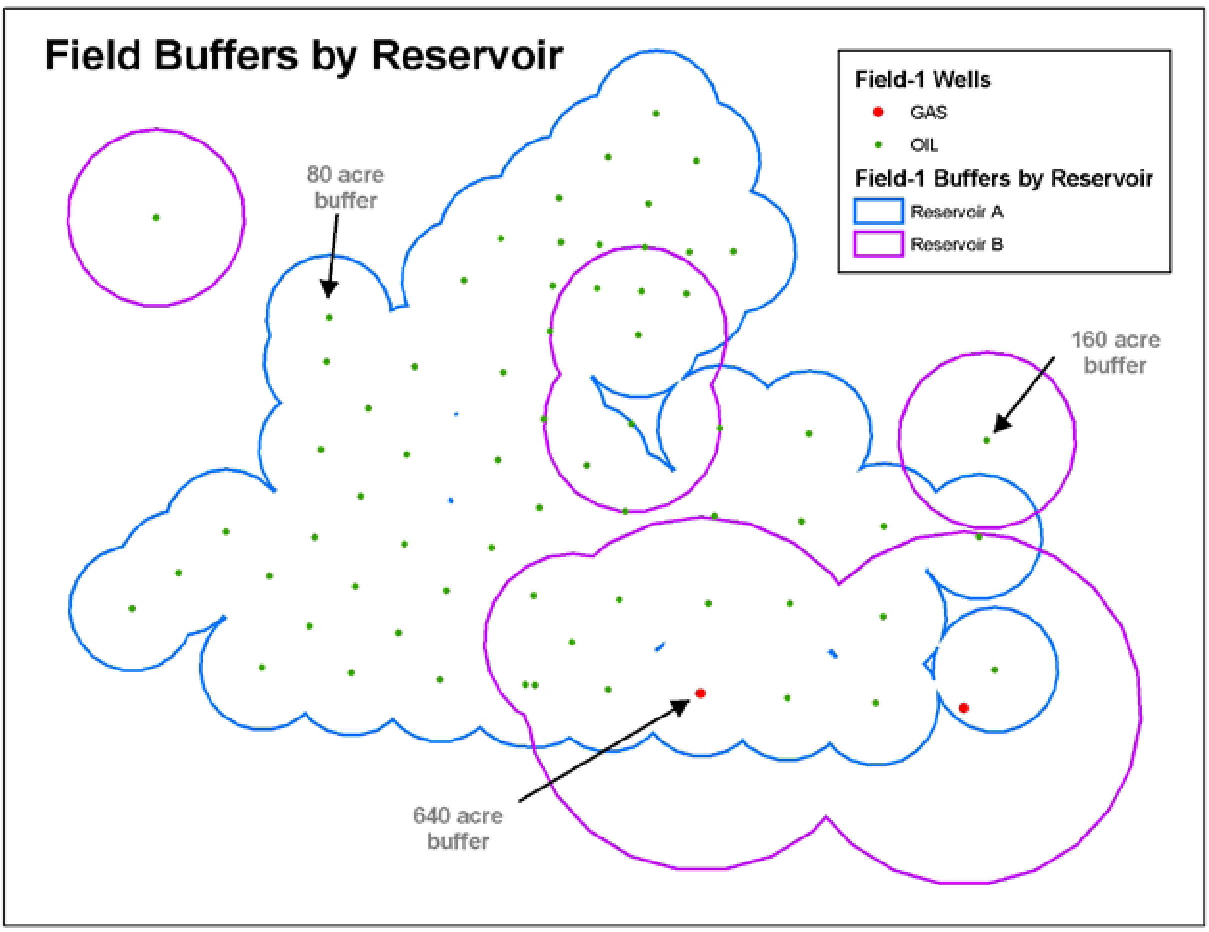

Figure A8-5. Field Buffers by Reservoir

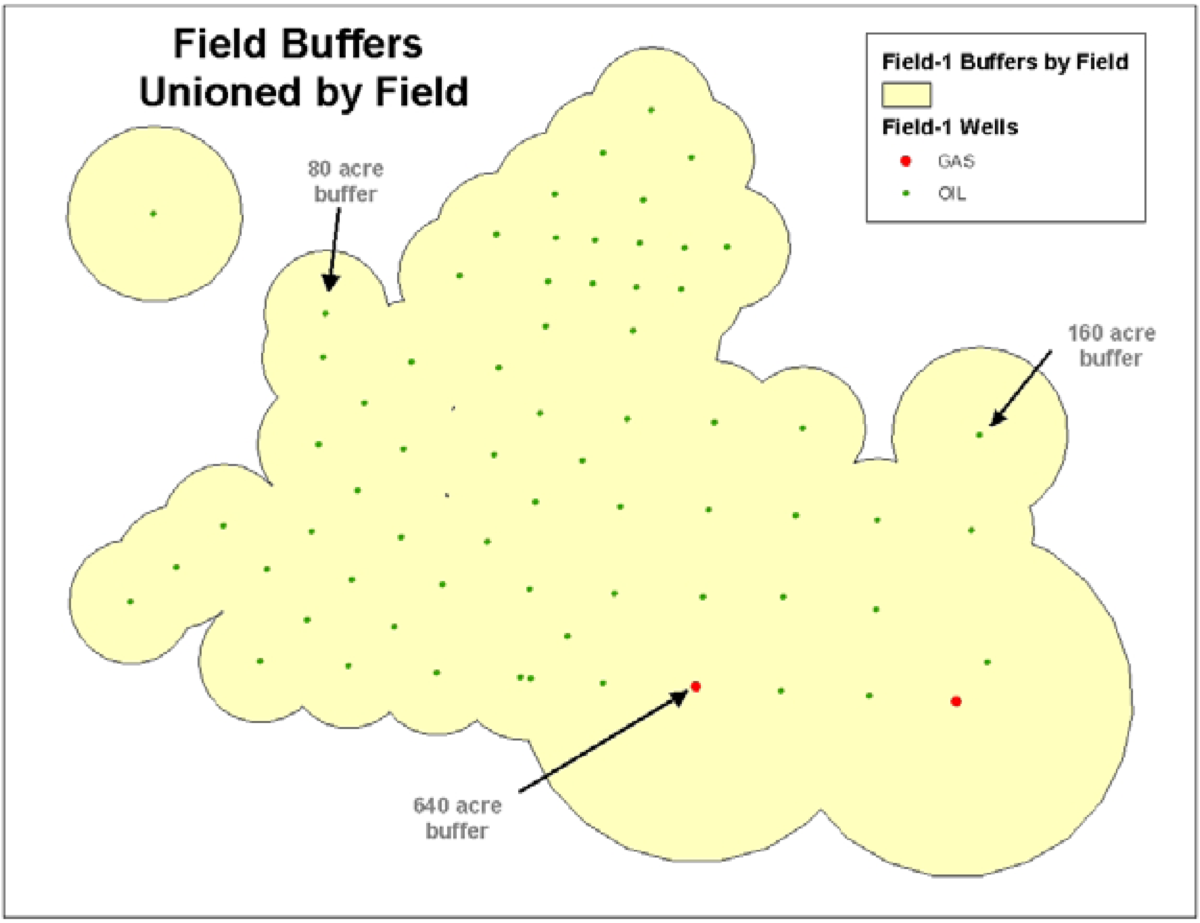

Figure A8-6. Field Buffers by Field

A8.10 Smoothing of the Field Boundaries

An algorithm was developed during the EPCA Phase I study to smooth field boundaries, the logic and processes of which are repeated below.

An artifact of the well buffer approach to field boundary construction is that multi-well field boundaries inevitably have an irregularly scalloped, botryoidal (grape cluster-like) appearance. Field boundaries tend to be much smoother than that in their natural reality. Other artifacts that result from the well buffering approach include small interior non-field "islands" and small separations between multiple polygon "rings" of a single field boundary (see Figure A8-7). It is probable that in most instances (1) the interior islands are legitimately part of the field area and should therefore be included in it, and (2) that the "outlier" polygons of a field should be joined with (i.e., bridged into) the main field boundary when the separation distance is sufficiently small. That is the way a geologist or petroleum engineer would subjectively draw the field boundary by hand based on only the well spud point location and well spacing information available for use in the EPCA studies (i.e., absent subsurface information). For EPCA Phase II the field boundary construction effort was therefore enhanced by development and inclusion of a methodological extension

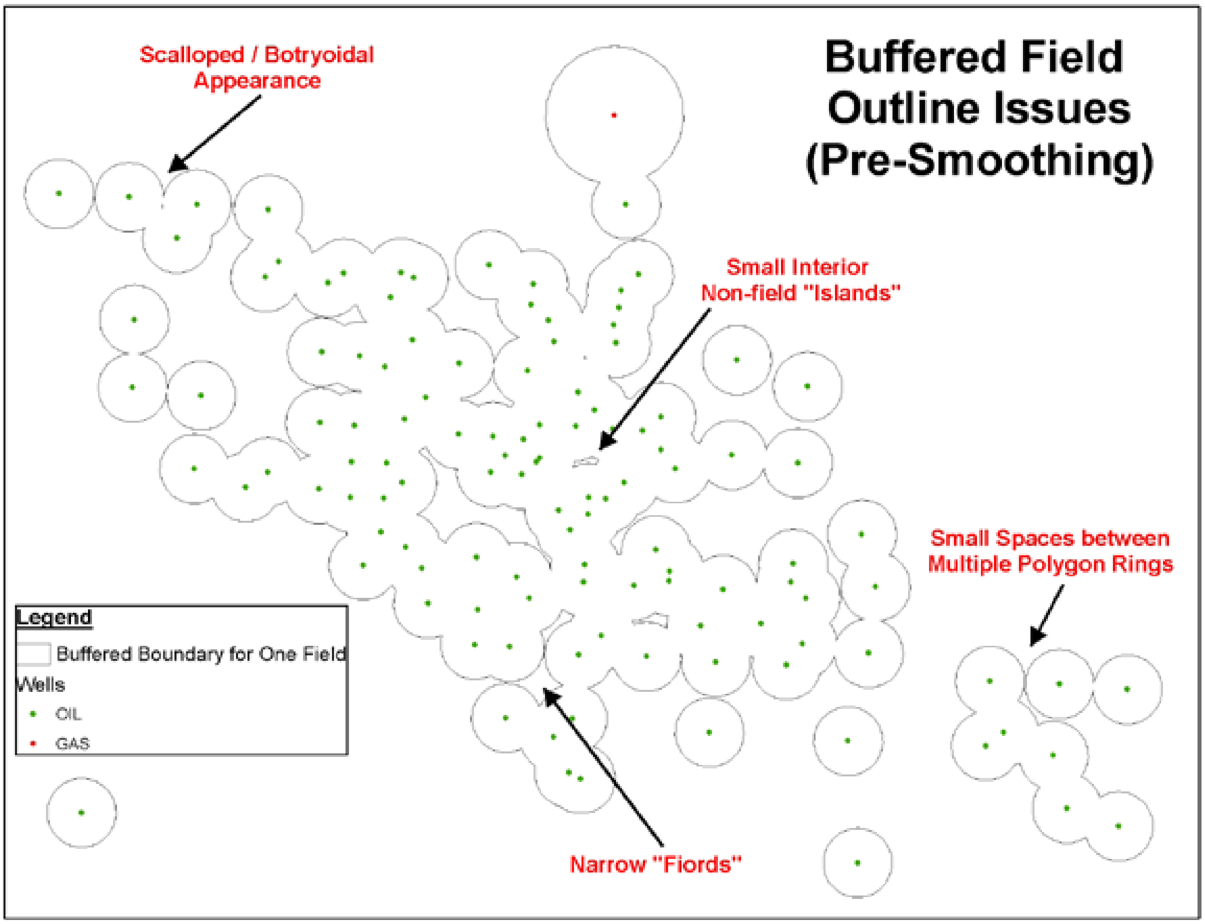

Figure A8-7. Buffered Field Outline Issues

that both automatically and more closely approximates what a geologist or petroleum engineer would draw as the field boundary. To have a consistent set of field boundaries for all of the EPCA phases, this extended methodology was also applied to upgrade the Phase I study area/basin field boundaries.

A Visual Basic application that could be implemented within ArcGIS to smooth the irregular boundaries and fill in the smaller spaces in an automatic, quick, systematic, consistent, and repeatable manner was developed. The guiding principles adhered to in development of the smoothing application were to (1) add field area to the concave indented portions to smooth the scalloped look, (2) not add or subtract area from the convex portions in order to maintain the well buffer spacing, (3) fill in the interior non-field “islands” that are smaller than the buffer size as these are very likely part of the actual field area, (4) join separated polygon “rings” of the same field by a “bridge” if they are sufficiently close together, and (5) minimize the concomitant increase in the field’s area. A number of alternative smoothing techniques were considered, tested, and rejected before the implemented technique was selected. These included:

- Raster Filters: Buffered field boundaries were converted from vector (point-line-polygon) format to raster (pixel) format. A variety of neighborhood statistical operators (filters) were applied to the raster and then converted back to vector format. This approach was not satisfactory because it always added field area to the convex portions of boundaries.

- Generalize and Smooth methods: These two vector-based methods are built into the ArcGIS software. The Generalize method was not chosen because it consistently subtracts area from the convex portions of field boundaries. The Smooth method results in inconsistent addition and subtraction of field area in the convex and concave portions of a field boundary, also not acceptable.
- Maximum angle technique: This technique first filled in and merged all interior non-field islands smaller in area than the maximum field buffer size. It then stepped along each vertex in a polygon and moved the vertex out until the angle formed by that vertex and the two vertices on either side of it was less than a maximum specified angle. Because moving one vertex out affects the angles of adjacent vertices, it required many iterations to get all angles to be less than the maximum allowed angle. Also, narrow fiord-like indentations in the field boundaries were particularly problematic with this technique and needed to be manually addressed prior to automated movement of the vertices. The increased complexity, human resource needs, longer processing time, and inconsistent handling of problems made this technique undesirable.

A technique based on tangent trapezoids was ultimately selected for field boundary smoothing because it focuses on how close wells in a field should be in order for their associated buffers to be unioned and is also simpler than the other tested techniques. It's begins by comparing the distance between each pair of wells within a field boundary to the average of the two wells' calculated buffer sizes. Three cases for the tangent trapezoid technique based on that relative distance are summarized in Figure A8-8. If the inter-well distance is less than or equal to two times the average buffer size, the buffers are either tangent (just touching) or overlapping (Figure A8-8a). When that is the case a trapezoid is constructed through both wells that extends to the full diameter of the buffers and is then unioned to the boundary polygon for that field. If the inter-well distance is between 2 to 2.5 times the average buffer size a trapezoid of one-half the buffer diameter is constructed and unioned to the boundary polygon for that field (Figure A8-8b). This thinner union of the well buffers reflects a higher uncertainty that the field is hydraulically connected in the subsurface within the space between the wells. If the inter-well distance is greater than 2.5 times the average buffer size no trapezoid is drawn and the field outline remains segmented (Figure A8-8c).

In addition to filling in the concave boundary areas, the tangent trapezoid technique aptly handles the matter of interior non-field "islands," fiord-like indentations in the field boundary, and spaces between multiple polygon "rings" belonging to the same field. Figure A8-9 shows an example of a field boundary before and after smoothing via the tangent trapezoid technique. The ratio of smoothed boundary area to unsmoothed boundary area was calculated in each instance to ensure that field area additions were sufficiently minimized. The mean increase in field area from unsmoothed to smoothed boundaries was 4.2 percent for all basins combined. Less than 1 percent of all fields examined

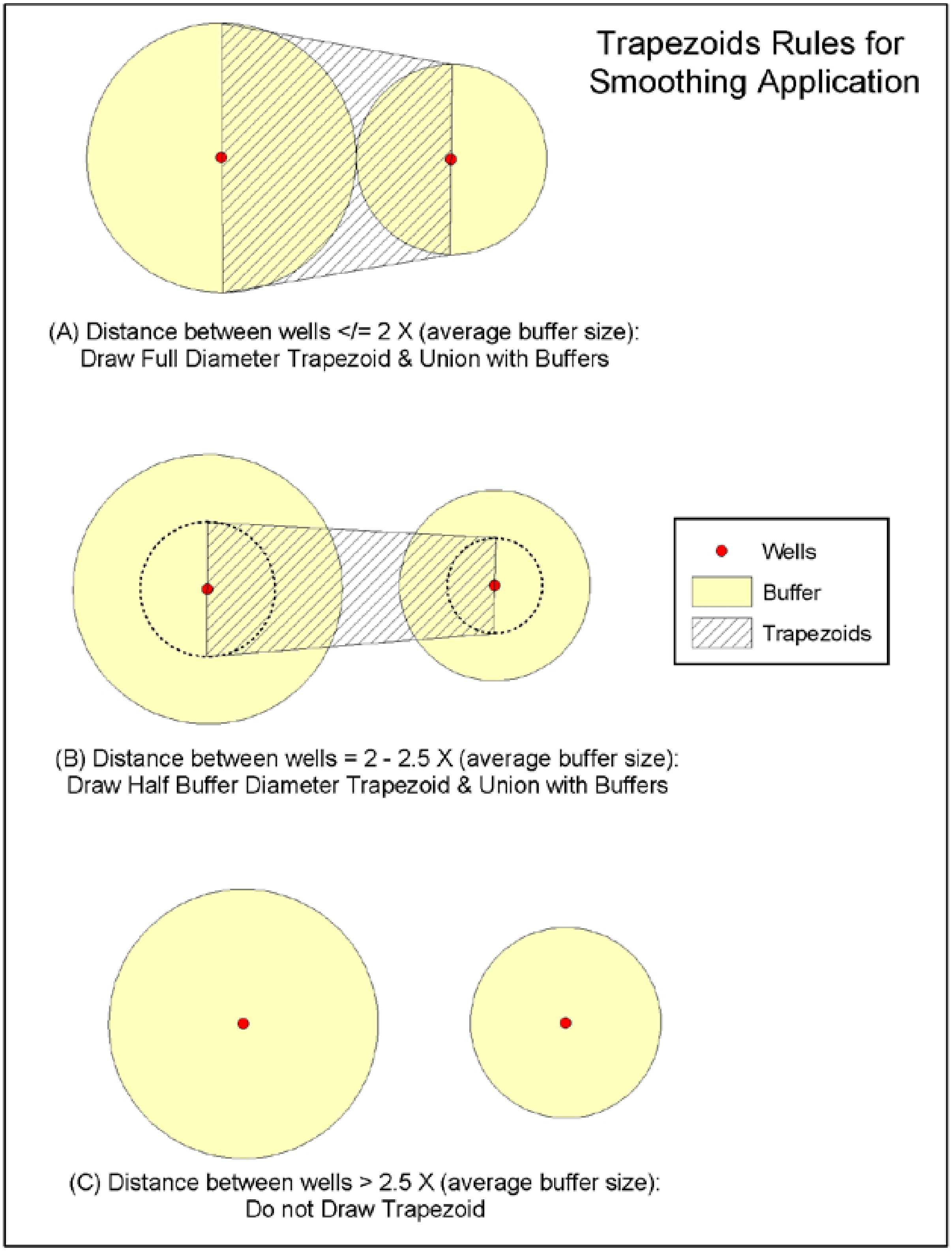

Figure A8-8. Tangent Trapezoid Smoothing Rules

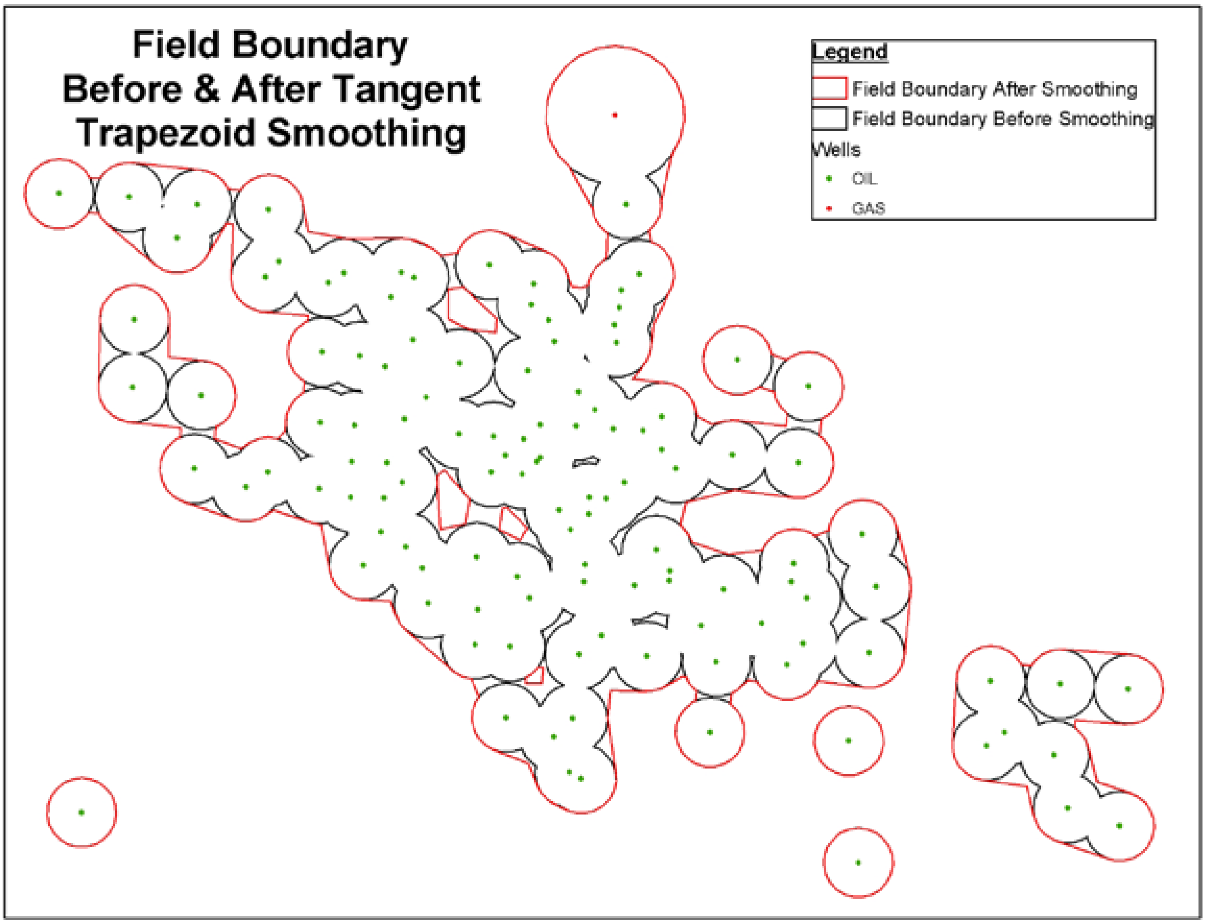

Figure A8-9. Field Boundary Before and after Smoothing with Tangent Trapezoid Technique

in EPCA Phase II exceeded an 8 percent change, and only 0.02 percent of all fields had a 10 to 14 percent change.

Field boundary polygons that crossed study area/basin boundaries were exported as a separate file, and were then clipped to the study area/basin boundary polygon files. For each of these fields the ratio of field area after clipping (area inside basin) to total field area (area inside + area outside basin) was calculated as the attribute INBAS_FRC (in-basin fraction). The value of this attribute is 1 for fields located entirely inside a study area/basin and ranges from greater than zero to less than 1 for those fields that cross a study area/basin boundary. Because the EPCA study only covers onshore areas, it was also necessary to clip (remove) the offshore portions of fields located in the Cook Inlet (Southern AK), the Arctic Ocean (Northern AK), and the Pacific Ocean (Ventura Basin). It was necessary to clip these fields before calculating the Federal land fraction because the BLM-provided Federal land coverages do not always extend far enough outside the study area/basin boundaries to permit its calculation for the entire unclipped field boundaries. Exceptions to this technique were if the field had only one well, or if the clipped portion extended outside of the USA into Canada (from MT or ND, Williston Basin). In these cases the outlines were clipped, but the in-basin fraction was assumed to be equal to one. The attribute INBAS_FRC is later multiplied by the field reserves to derive field reserves located inside the study area/basin boundary.

A8.11 Calculation of the Federal Lands Fraction Within a Field's Boundary

The Federal land ownership coverages provided by the BLM, DOI (one coverage per basin) were intersected with the field boundary outlines to ascertain the Federal ownership aspect of each field's area. For the purposes of this study, split estate lands where either the surface rights or the mineral rights are owned by a Federal government agency are considered to be "Federal lands". An automated procedure (developed for EPCA Phase I) was used to calculate the fraction of Federal land within each oil and gas field polygon. The procedure intersected the Federal land coverages with the field polygons and then populated a column in the field boundary polygon table "PctFedLand."

A8.12 Review and Quality Control of the Resulting Maps

Maps were printed at an appropriate scale for each study area/basin to facilitate quality checking of the constructed field boundaries both before and after the smoothing algorithm was applied. These maps displayed the wells in the field and the field boundary polygons. They also showed selected field attributes such as state, county, basin, and percent Federal land. Figure A8-10 provides an example of a quality control map.

A8.13 Field-Level Proved Reserves Estimation

The conditioned state/vendor well history and production data were summed to the field/operator level and then merged with the field proved reserves estimates reported on Form EIA-23 by the largest operators. Fields were classified into four types for the purpose of reserves estimation:

- Fields with no 2004 production data or reserves estimate data.
- Fields that were completely reported by both USPS and the EIA survey, with 2004 production and all operators in the fields being surveyed by EIA. The proved reserves estimates submitted by the operators for these fields were used as reported.
- Fields that were partially reported and partially imputed. These fields are represented in both the USPS and EIA survey data by 2004 production volumes, but only part of the total field reserves estimate was reported to EIA because some operators in the field were not required to report proved reserves on Form EIA-23. The remainder of the field's proved reserves was therefore imputed by RPD by assigning the weighted average reserves-to-production ratio of the reporting operators to the non-reporting operators and multiplying it by the non-reporting operators' reported production volumes as taken from state/vendor data.
- Fields that were completely estimated based on state/vendor 2004 production

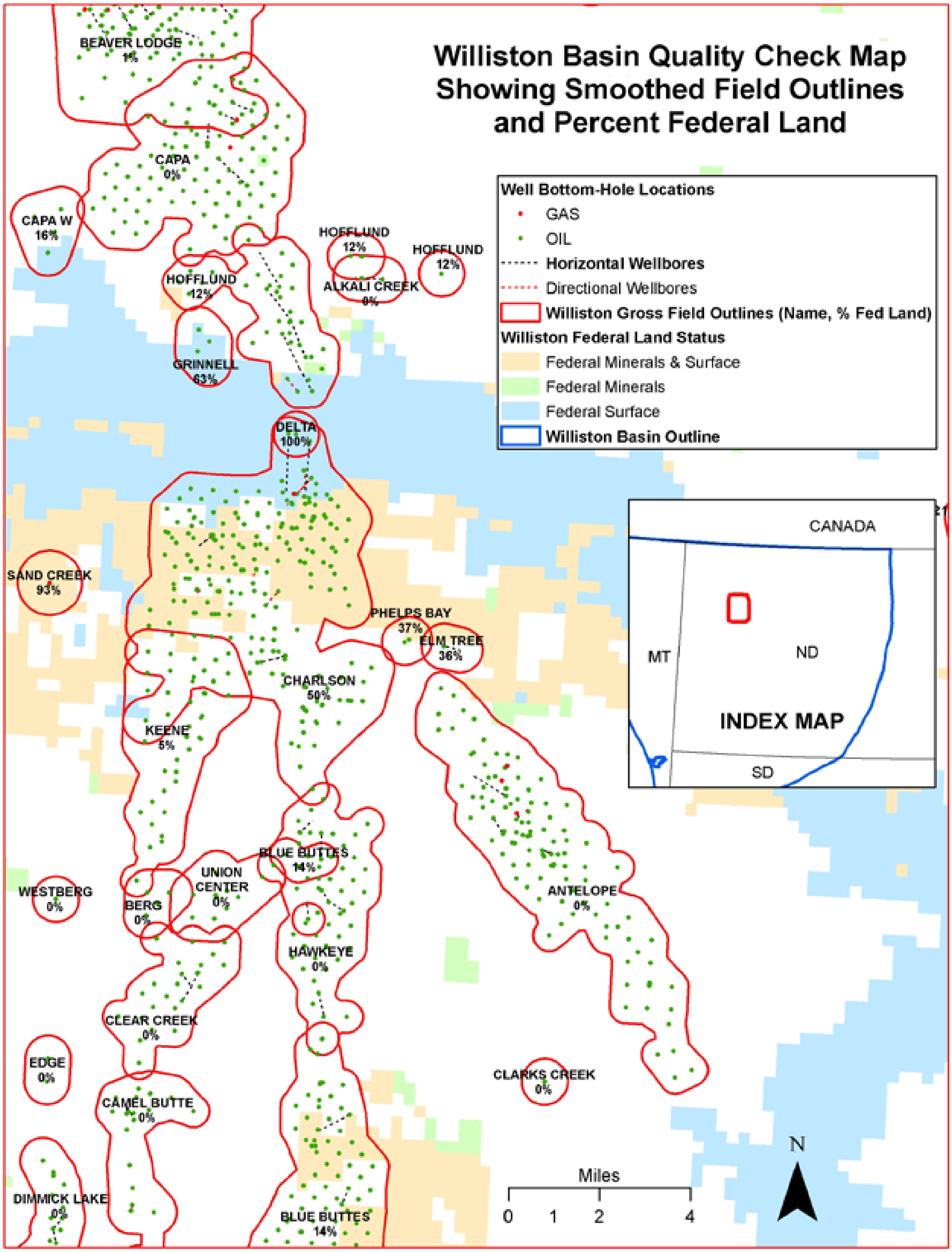

Figure A8-10. Williston Basin Quality Check Map Showing Smoothed Field Outlines and Percent Federal Land data because the operators of these fields were not required to submit a Form EIA-23. Although these fields constitute a sizeable fraction of the total number of fields in the study areas/basins, their aggregate proved reserves represent only a small portion of total proved reserves. The proved reserves and corresponding production data reported on the 2004 Form EIA-23 were used to develop predictive least squares regression equations quantitatively descriptive of their relationship. These equations were then used to estimate proved reserves for this class of fields based on the state/vendor production data available for them. The estimation equations were developed using SAS statistical software, one each for oil, associated-dissolved gas, non-associated gas, and condensate, for each basin, state (including fields both in-basin and outside-basin) and the United States as a whole. The form of the equation is:

$$\log_e (\textit{Proved Reserves}) = a + b \log_e (\textit{Production})$$

Table A8-6 lists the resulting regression parameters. For any field where reserves were imputed, the basin-level parameters were used if available, followed in their absence by state-level parameters if available, followed in the absence of both by US-level parameters. Where no parameter is listed in the table there was not sufficient data available for that basin or state to validly estimate the parameter.

The resultant crude oil proved reserves estimates were then summed with the proved condensate reserves estimates to yield the proved liquid reserves estimates. Similarly, the proved associated-dissolved gas reserves estimates and the proved non-associated gas

Table A8-6. Regression Equation Parameters for the Estimation of Non-Reported Reserves for EPCA Phase III

		Regression Parameters							
		Crude Oil		Associated-Dissolved Gas		Non-Associated Gas		Condensate	
		a	b	a	b	a	b	a	b
Basin	EASTERN GREAT BASIN								
Equations	NORTH ALASKA BASIN								
	SOUTH ALASKA BASIN								
	VENTURA BASIN								
	WILLISTON BASIN	1.58	1.11	1.68	1.05	1.35	1.10		
State	AK	1.21	1.08	1.35	1.12	3.42	0.76		
Equations	CA	1.67	1.09	1.92	1.02	1.41	0.96		
	MT	1.58	1.14	1.54	1.15	2.29	0.96		
	ND	1.66	1.07	1.74	1.01	.	.		
	NV	1.72	1.09	2.05	0.97	1.56	1.07		
	SD	1.66	1.07	1.74	1.01	.	.		
	UT	1.72	1.09	2.05	0.97	1.56	1.07		
Country Equation	USA	1.68	1.01	1.74	0.96	2.10	0.91	1.54	0.84

reserves estimates were summed to yield the total proved gas reserves estimates. Lastly, a gas-to-oil ratio of 6000 cubic feet per barrel was used to convert the total proved gas reserves to their oil equivalent, which was then summed with the proved liquid reserves estimates to yield the proved barrel of oil equivalent reserves estimates.

For each of the four reserve types Table A8-7 summarizes by study area/basin the number of fields, the basin field count, the barrel of oil equivalent production, and the barrel of oil equivalent proved reserves. The percentage of each reserve type in the study area/basin is also shown.

A8.14 Calculation of Federal Reserves

The Federal reserves for each field were estimated by multiplying the fraction of Federal land for each field (derived by GIS analysis as described above) by the proved reserves estimates for each product. This procedure assumes that the distribution of proved reserves per unit area within a field boundary is uniform. While that is never precisely the case, this procedure is sufficiently precise for a regional study such as this one.

A8.15 Reserves Classification

In order to sufficiently protect the proprietary proved reserves data submitted to EIA, each field was then assigned to a gross reserves size class and a Federal reserves size class, by product, per the following classification scheme:

Class Number	**Proved Liquid Reserves**
0	Zero reserves (i.e., no recorded 2004 production)
1	Greater than zero but less than 10 Mbbls liquid

Table A8-7. Field Count, BOE Production & BOE Reserves for Four Reserve Types in Each Study Area/Basin of EPCA Phase III

Study Area/ Basin Name	Reserve Type	Field Count	% Basin Fld Cnt	BOE Prod	% Basin BOE Prod	BOE Res	% Basin BOE Res
EASTERN GREAT BASIN	No 2004 Production/Reserves	16	55.17	-	0.00	-	0.00
EASTERN GREAT BASIN	Completely Estimated	13	44.83	464	100.00	3,764	100.00
NORTH ALASKA BASIN	No 2004 Production/Reserves	4	17.39	-	0.00	-	0.00
NORTH ALASKA BASIN	Completely Reported	19	82.61	336,711	100.00	5,089,638	100.00
SOUTH ALASKA BASIN	No 2004 Production/Reserves	10	37.04	-	0.00	-	0.00
SOUTH ALASKA BASIN	Completely Reported	17	62.96	22,711	100.00	225,148	100.00
VENTURA BASIN	No 2004 Production/Reserves	33	38.37	-	0.00	-	0.00
VENTURA BASIN	Completely Estimated	14	16.28	223	1.44	1,544	0.60
VENTURA BASIN	Completely Reported	22	25.58	9,353	60.38	165,217	64.10
VENTURA BASIN	Partialy Reported/Imputed	17	19.77	5,916	38.19	90,982	35.30
WILLISTON BASIN	No 2004 Production/Reserves	403	42.15	-	0.00	-	0.00
WILLISTON BASIN	Completely Estimated	228	23.85	4,280	6.15	30,777	3.38
WILLISTON BASIN	Completely Reported	162	16.95	21,233	30.50	298,873	32.80
WILLISTON BASIN	Partialy Reported/Imputed	163	17.05	44,143	63.40	581,494	63.82

2	Greater than 10 but less than 100 Mbbls liquid
3	Greater than 100 but less than 1000 Mbbls liquid
4	Greater than 1000 but less than 10,000 Mbbls liquid
5	Greater than 10,000 Mbbls liquid

Class Number	Proved Gas Reserves
0	Zero reserves (i.e., no recorded 2004 production)
1	Greater than zero but less than 10 MMCF gas
4	Greater than 10 but less than 100 MMCF gas
5	Greater than 100 but less than 1000 MMCF gas
4	Greater than 1000 but less than 10,000 MMCF gas
5	Greater than 10,000 but less than 100,000 MMCF gas
6	Greater than 100,000 MMCF gas

Class Number	Proved Barrel-of-Oil Equivalent Reserves
0	Zero reserves (i.e., no recorded 2004 production)
1	Greater than zero but less than 10 MBOE
2	Greater than 10 but less than 100 MBOE
3	Greater than 100 but less than 1000 MBOE
4	Greater than 1000 but less than 10,000 MBOE
5	Greater than 10,000 but less than 10,000 MBOE
6	Greater than 10,000 MBOE

Note: M=1,000; MM=1,000,000; bbls=barrel; CF=cubic feet

A8.16 Merging Of Proved Reserves Classes With Field Boundaries And Fraction Of Federal Land

A table with the gross reserves classes by field (range 0 to 6) and the field name was merged with the gross field boundaries to produce a gross field boundary shapefile with reserve classes. A Federal field boundary GIS file was produced that contains the intersection of the Federal land coverages with the gross field boundaries. Owing to the existence of multiple Federal land parcels within each field boundary, the resultant boundary polygons were then dissolved on the attribute field to union the data into one polygon record per field. A table with the Federal reserves classes by field (range 0 to 6) and the field name was then joined to the shapefile associated with the Federal field boundary shapefile. The latter was then converted to coverage format and thence to interchange file format (.e00).

For all basins there was good correspondence between the production file and the map file with Federal land percentages.

A8.17 Summary of Results

GIS is clearly the information conveyance method of choice where both analysis of Federal lands policy and regulations and their application are concerned. The primary proved reserves result is therefore a GIS layer containing field boundary polygons attributed with field name and a proved reserves size class for each field product. Unfortunately, none of this very detailed information can be usefully conveyed on a piece of paper this size. You have to use a GIS workstation to view it and a wide-format printer to print it at a size where the detail can be distinguished. Therefore, in lieu of a close look at the reserves results, basin-by-basin summary statistics are provided in Table A8-8.

Table A8-8. Summary of 2004 Federal Lands Proved Reserves by Study Area for EPCA Phase III

Study Area	Number of Fields	Total Oil Reserves (MMbbl)	Federal Land Oil Reserves (MMbbl)	Federal Portion of Total Oil Reserves	Total Gas Reserves (Bcf)	Federal Land Gas Reserves (Bcf)	Federal Portion of Total Gas Reserves
Northern Alaska*	23	4,034.0	3.3	0.1%	6,334.1	4.8	0.1%
Central Alaska	0	0.0	0.0	0.0%	0.0	0.0	0.0%
Southern Alaska*	27	2.7	0.2	8.0%	1,334.7	47.8	3.6%
Eastern Oregon/Washington	0	0.0	0.0	0.0%	0.0	0.0	0.0%
Ventura Basin*	86	215.5	12.1	5.6%	253.5	19.2	7.6%
Eastern Great Basin*	29	3.8	3.7	99.5%	0.0	0.0	94.7%
Uinta-Piceance Basin	180	254.3	142.9	56.2%	7,181.7	3,794.1	52.8%
Paradox Basin	171	119.4	36.3	30.4%	14,156.0	7,497.4	53.0%
San Juan Basin	79	54.8	16.7	30.4%	6,497.7	3,441.3	53.0%
Montana Thrust Belt	0	0.0	0.0	-	0.0	0.0	-
Williston Basin*	955	769.0	172.9	22.5%	840.6	173.0	20.6%
Powder River Basin	543	193.5	109.0	56.3%	2,398.6	935.8	39.0%
Wyoming Thrust Belt	28	34.6	13.8	39.8%	1,141.3	474.5	41.6%
Southwestern Wyoming	281	177.4	122.4	69.0%	12,703.0	10,063.5	79.2%
Denver Basin	1,638	148.3	2.5	1.7%	2,736.7	30.4	1.1%
Florida Peninsula	21	20.4	0.0	0.0%	0.0	0.0	0.0%
Black Warrior Basin	235	0.6	0.0	0.4%	1,248.3	17.7	1.4%
Appalachian Basin	3,354	79.1	0.2	0.2%	9,550.2	28.0	0.3%
Total	7,650	6,107	636	10.4%	66,376	26,528	40.0%

* *Reserves calculated for Phase III*