2.0 METHODOLOGY

The Phase II inventory examines the following geologic provinces:[1]

- Northern Alaska (NA; NPR-A and ANWR 1002 only)
- Uinta-Piceance Basin (UP)
- Paradox/San Juan Basins (PDX/SJ)
- Montana Thrust Belt (MTB)
- Powder River Basin (PRB)
- Wyoming Thrust Belt (WTB)
- Greater Green River Basin (GGRB)
- Denver Basin (DEN)
- Florida Peninsula (FLP)
- Black Warrior Basin (BWB)
- Appalachian Basin (APB).

The study areas were delineated by aggregating oil and/or natural gas resource plays[2] within the provinces as defined by the USGS National Assessment of Oil and Gas Resources. Resource play boundaries and oil and gas resource estimates within the plays were obtained in GIS format from the USGS. These plays were then aggregated in a GIS to create a resource density map layer for each study area.

Where play boundaries span more than a single geologic province, one province was selected over the other in order to preserve geographic uniqueness. For example, at the boundary of the PDX/SJ and UP study areas, the UP was defined by the outline of Uinta plays even though these plays overlap plays from the Paradox Basin. The Uinta/Piceance study area thus contains some Paradox Basin resources and reserves. Likewise, the WTB and GGRB study areas were defined by the GGRB USGS boundaries and the DEN and PRB study areas by the PRB USGS province boundaries.

Federal land status was generated using the “Status” dataset from the BLM’s Legacy Rehost 2000 (LR-2000) system to create GIS maps. Oil and gas leasing stipulation and COA data were obtained for each jurisdiction from BLM field offices and USDA-FS offices in the study areas. Most of the stipulation data were available in GIS format; some existed only as hardcopy and had to be digitized to create GIS digital map files.

Stipulations and COAs are additional requirements that are attached to Federal oil and gas leases and drilling permits for environmental protection and other reasons and are subject to change over time. This inventory represents a "snapshot" of the conditions within the study areas at the time of data collection. The stipulations used in the inventory are those applied when new oil and gas leases are issued and are those

[1] The study areas in this document are referenced in USGS Oil and Gas province order.
[2] “Plays,” more recently referred to as “assessment units,” are a set of known or postulated oil and gas accumulations having similar geologic origins. The term plays is used generically in this document (see section 2.2.1 for further explanation).

contained primarily in National Forest Plans (FPs) and BLM Resource Management Plans (RMPs) in effect as of August 2002 (for the UP, PDX/SJ, MTB, PRB, and GGRB study areas), March 2005 (for the WTB, DEN, FLP, BWB, and APB study areas) and January 2006 (NA study area). Some stipulations are not maintained in an automated system and may not have been available for use in this inventory (see Section 2.1.2 for further discussion).

The analyses entailed the spatial intersection (in a GIS) of oil and gas resource information with data on Federal land status and access constraints. The inventory also takes into account how leasing stipulations are implemented in practice by Federal land managers by considering the effect of directional drilling and the general frequency with which exceptions to the stipulations are granted.

To the extent that current leases were issued under and are stipulated according to an existing land use plan, the inventory accurately reflects the access situation. Older leases issued before the effective date of the relevant plans may not be stipulated accordingly. It is reasonably accurate, however, to consider the plan stipulations as a proxy because the environmental conditions that necessitate stipulations often are the driver for COAs that are attached to drilling permits on the older unstipulated leases to achieve the needed environmental protection.

Additional factors exist that affect oil and gas exploration and development on Federal lands and cannot be quantified geographically prior to the receipt of a specific drilling application. The factors include:

- Protection for threatened, endangered, and sensitive species. Surveys are sometimes required to determine whether a lease contains habitat for such species.
- Archaeological surveys required by the National Historic Preservation Act, along with related issues involving cultural resources, including consultation with Native American tribes.
- Air quality impacts and resulting restrictions on activities that may affect air quality.
- Visual impacts of oil and gas operations.
- Noise from oil and gas operations.
- Suburban encroachment on oil and gas fields and county government restrictions.

Section 4 of this report presents these issues in greater detail. Many of these requirements manifest themselves as COAs attached to drilling permits following a specific analysis under the National Environmental Policy Act (NEPA). These requirements can delay or modify a planned oil and gas development activity at the permit stage and in some cases preclude it altogether. Site-specific COAs have been incorporated into the inventory.

The rest of this section provides a more detailed description of the inventory methodology.

2.1 PROCEDURES FOR COLLECTING AND PREPARING LAND

STATUS AND OIL AND GAS ACCESS CONSTRAINTS

2.1.1 Federal Land Status

This section briefly presents the process for determination of land status. See Appendix 3 for a more detailed description.

2.1.1.1 Sources of Land Status Data

In contrast to the Phase I inventory, which exclusively examined basins in the Interior West, Federal lands status determination was much more complex for the Eastern study areas included in the Phase II inventory (FLP, BWB, and APB). For the Eastern study areas the mapping of Federal lands was completed based upon detailed research of multiple sources of information that describe the nature and extent of Federal surface and mineral interests. The primary source of Federal land status data outside of the Eastern areas was the BLM's LR-2000 Status Dataset, which was supplemented by other records from Federal, state, and county governments.

2.1.1.2 Land Status Data Preparation

These data, which are often stored in alphanumeric format, were converted as necessary for this inventory into a GIS layer by using commercially available software. The software interpolated the legal descriptions contained in the Status Dataset against a public land survey GIS layer derived from either the BLM's Geographic Coordinate Database (GCDB) or other sources such as digitized USGS 7-1/2 minute quadrangle maps.

Maps of the Federal land status for the study areas are presented in Figures 2-1 through 2-11.

Figure 2-1. Federal Land Status Map, Northern Alaska Study Area

Figure 2-2. Federal Land Status Map, Uinta-Piceance Basin Study Area

Figure 2-3. Federal Land Status Map, Paradox/San Juan Basins Study Area

Figure 2-4. Federal Land Status Map, Montana Thrust Belt Study Area

Figure 2-5. Federal Land Status Map, Powder River Basin Study Area

Figure 2-6. Federal Land Status Map, Wyoming Thrust Belt Study Area

Figure 2-7. Federal Land Status Map, Greater Green River Basin Study Area

Figure 2-8. Federal Land Status Map, Denver Basin Study Area

Figure 2-9. Federal Land Status Map, Florida Peninsula Study Area

Figure 2-10. Federal Land Status Map, Black Warrior Basin Study Area

Figure 2-11. Federal Land Status Map, Appalachian Basin Study Area

2.1.1.3 Land Status Data-Related Caveats

The following precautions are advised when reviewing this inventory:

- The land status data are generally spatially accurate down to 40 acres. The data vintage is August 2002 for the Phase I basins and March 2005 for the Phase II basins.
- The GIS files, created using the processes described in detail in Appendix 3, were interpolated from the legal land descriptions contained in the BLM's LR-2000 database. If a legal description referenced a small survey lot or tract by number, a nominal location was mapped through a process that referenced the Legal Land Description dataset. This dataset is limited to a 40-acre description and therefore carries a minor degree of generalization in complex areas. Isolated parcels of less than 40 acres, particularly in the Eastern study areas, were not included in the inventory.
- This mapping process uses public land survey data derived from various sources. The spatial location of the land status parcels so derived matches the accuracy of the survey data.
- Some land status GIS data are restricted from the public domain by agency request. Such data were used in the analyses presented in this report, but are not contained in the public datasets.

For purposes of this inventory, Federal lands include split estate. In cases of split estate where the Federal government holds a partial interest in the oil and gas mineral estate, the Federal government was assumed to hold total mineral interest.

Table 2-1. Federal Land Acreage by Surface Management Agency

2.1.2 Federal Oil and Gas Availability for Leasing and Lease Stipulations

All onshore Federal oil and gas leases contain terms and conditions as specified on the standard lease form (BLM Form 3100-11).[3] Some of these terms and conditions govern land use and resource development to a certain extent. Environmental and other considerations, which are identified during the land use planning process, determine the need for additional terms and conditions, also known as lease stipulations. For example, a lease may contain a stipulation that prohibits surface disturbance during certain time periods for wildlife. Such stipulations on land use and timing may constrain exploration and development of oil and natural gas on Federal lands.

Some Federal lands are unavailable for leasing. See Table A9-2 in Appendix 9 for a listing of agencies and Federal designations that generally prohibit oil and gas leasing.

The Federal government does not issue oil and gas leases for areas where it has surface ownership but no mineral rights. In such instances, the Federal government, while allowing access to the subsurface resources owned by another party, typically uses surface occupancy restrictions (SORs) to protect surface resources. From the

[3] The form is available at https://www.blm.gov/FormsCentral/show-form.do?nodeId=687#

standpoint of the EPCA inventory, SORs and lease stipulations have similar impacts. Thus, for the purposes of this study, the term "stipulations" is used generically to include SORs.

2.1.2.1 Sources of Lease Stipulation Data

Oil and gas lease stipulations are derived from the Federal surface management agency's land use plans, e.g., Resource Management Plans (RMPs) for the BLM and Forest Plans (FPs) for the Forest Service. These plans are produced and maintained by their respective agencies on a field office jurisdictional basis (in the case of the BLM), or on a National Forest/Grassland basis (in the case of the USDA-FS). Land use planning documents are revised every ten to fifteen years, or on an as-needed basis, but may be amended to address specific land use issues. Table 2-2 lists the land use planning documents used for this inventory.

Table 2-2. Land Use Plans by Study Area

Hardcopy and digital data showing the mapped lease stipulation areas were collected from BLM and Forest Service offices within the study areas (see Table 1-1). During office visits, copies of guidance documents, such as RMPs and FPs, were also obtained.

Most of the lease stipulation data are maintained by the agencies as GIS data layers (digital map files). Some offices, particularly where the planning effort pre-dated the widespread availability of GIS technology, maintain this information in the form of hardcopy maps. For this inventory, these maps were digitized, stored, and analyzed as GIS layers. The digitized maps were then returned to the originating field offices for review and future use.

For some BLM and USDA-FS plans, maps are not available for some stipulations either in GIS or hardcopy form. Stipulations for which GIS data are not available or could not be generated from other data sources are annotated on the stipulations lists accompanying this report.[4]

Data for this study were collected during the two phases of the inventory. For the UP, PDX/SJ, PRB, and MTB study areas, data were collected in the winter of 2001-2002. For the GGRB study area, data were used from the DOE's Federal lands analysis[5] collected during the fall and winter of 2000-2001; these data were verified with the local BLM and USDA-FS offices and were current as of August 2002. The data for NA were collected in the fall of 2003. Data for the WTB, DEN, BWB, FLP and APB were collected during 2004. These data were verified with the local BLM and USDA-FS offices and were current as of March 2005.

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[4] The stipulation list for each Study Area exists as a Microsoft Access Table within its respective ESRI geodatabase on the DVD. It can either be imported into an ArcMap project or viewed directly in Access.

[5] Federal Lands Analysis, Natural Gas Assessment, Southern Wyoming and Northwestern Colorado, Study Methodology and Results, June 2001, available on the DOE website: http://fossil.energy.gov/programs/oilgas/publications/fla/Federal_Lands_Assessment_Report.html.

2.1.2.2 Lease Stipulation Data Preparation

Most of the lease stipulation data preparation consisted of the gathering, digitizing, and compiling of the gathered data in multi-layered digital map files. Federal Geographic Data Committee Standards (FGDC)-compliant supporting documentation (metadata) for the resulting GIS layers was also created.[6]

This inventory concerns only Federal lands within the aggregate resource play boundaries of the study areas, which are based on geology as defined in the USGS National Assessment of Oil and Gas Resources. Consequently, the land status and stipulation digital map files, which correspond to Federal land management agency jurisdiction boundaries, were clipped using GIS to fit within each of the study area boundaries. Data contained within the compiled digital map files were then queried for unique leasing stipulation values. The results were saved as separate map files. Each digital map file represents a unique stipulation value.

For a description of the specific data preparation steps, see Appendix 4.

2.1.2.3 Lease Stipulation Data-Related Caveats

The following precautions are advised when reviewing this study:

- All stipulations for which GIS data were available from the Federal land management agencies were used in the analysis. Most of the stipulations within the study areas were available in GIS data formats; however, supporting documentation was not generally provided with GIS files. Although this can lead to inaccuracies due to undocumented differences in technical parameters, such errors are minor in terms of the scope of the inventory.
- Many stipulations not available in GIS format were digitized. Any resulting inaccuracies due to this process are likely to have insignificant impacts upon the analysis.
- Neither hardcopy nor digital maps were available for some stipulations (see Section 2.3.1.1 for further discussion).
- The lease stipulation data are generally accurate to a minimum of 40 acres.
- Some lease stipulation GIS data are restricted from the public domain by agency request. Such data were used in the Phase II analysis but are not contained in the public datasets.

2.1.3 Federal Drilling Permit Conditions of Approval

As described in section 2.1.2, a Federal oil and gas lease conveys only the right to develop such resources on the leased land subject to reasonable regulations as determined by the land managing agency. After lease issuance, and prior to approval of any drilling activities, the operator must submit an Application for Permit to Drill (APD). An APD provides operational and geologic information as well as the applicant's

[6] GIS layers for surface management agency land status, stipulations, and the analyses, as well as the associated metadata, are available on the DVD and the web site.

proposal for use of the surface. COAs are post-lease requirements that are attached to an approved APD for environmental protection, safety, conservation of resource. COAs have been developed over a number of years as mitigation for surface disturbing activities and are based upon lease notices and/or administrative policy actions.

The Phase I inventory evaluated the impact of lease stipulations on access to oil and gas resources on Federal lands, but did not explicitly address the effects of COAs, assuming that they were implicitly covered by lease stipulations that would be issued for future leases. Subsequent to the Phase I inventory, the 2003 NPC study examined COAs as a complement to lease stipulations and concluded that COAs are a greater impediment to development than leasing stipulations.

Partially in response to the 2003 NPC study, and in anticipation of the inventory amendments contained in EPAct 2005, the effects of COAs on oil and gas accessibility have been incorporated into the Phase II analysis. The purpose of the inclusion of COAs is to enhance the land access constraints analysis and thus provide a more complete assessment of the onshore Federal lands' availability for oil and gas exploration and development.

COAs arise from a variety of controlling authorities, but the most significant and wide-ranging are those governed by four Federal laws; specifically, the Federal Land Policy and Management Act (FLPMA), the National Environmental Policy Act (NEPA), the Endangered Species Act (ESA) and the National Historic Preservation Act (NHPA). The COAs attached to each APD can be general in nature or site-specific, and thus vary from one BLM Field Office (FO) to another.

Some COAs can be identified as "best management practices" while others are included as a standard set by the approving office. In the Phase II study areas, approximately 175 types of COAs provide mitigation for surface-disturbing activities. For example, COAs can address:

- Big game winter range
- Protection of wildlife habitat
- Protection of archeological and paleontological sites
- Noise reduction
- Road construction and maintenance tanks and pits for fluid storage
- Pipeline and power line construction
- Wildfire suppression
- Management of noxious weeds
- Reclamation
- Erosion control
- Fertilizer application

COAs and stipulations beyond the standard lease terms often occur together. Prior to this inventory, there has not been a comprehensive method to characterize their impact on Federal land access. The National Petroleum Council, in its 2003 report (see

Section 1.5) crafted an ingenious method to estimate the effect that COAs have on Federal land accessibility. However, the NPC did not have access to the actual well files containing COAs, but instead used publicly available wildlife data as a proxy to estimate their impact. In examining COAs and their effects upon land access for this inventory, it was necessary for the BLM to review extensively the APD well records in its Field Offices. The methodology for the assessment of COAs is described in Appendix 5.

2.1.3.1 Sources of Conditions of Approval Data

For the Phase II inventory, a number of APDs for all study areas were sampled. The APDs were selected by applying a stratified random sampling protocol to a list of all APDs approved during fiscal years 1999-2004. The sample represents approximately 10 percent of the total population of APDs. BLM Field Offices were visited and information on site-specific COAs was abstracted from the hardcopy well files. A summarized version of the COAs and stipulations that affected oil and gas access in each selected APD was noted.

In addition, information was obtained from BLM Field Office personnel to qualitatively assess the extent of negotiations that occur prior to the submission of an APD, including adjustments at the time of well staking and are presented in Appendix 5.

2.1.3.2 Conditions of Approval Data Preparation

The COAs data preparation consisted of compiling the collected information into spreadsheets and spatial GIS displays. The abstracted information was grouped into general classes that were assigned unique codes. Table 2-3 presents a list by BLM office. Appendix 5 contains details on the data preparation task.

Table 2-3. COAs by BLM Field Office

2.1.3.3 Conditions of Approval Data-Related Caveats

The APDs examined were randomly sampled. To the extent that the sample is not representative of the population, extrapolation of sample results could introduce error.

Because of the large number of approved Federal APDs, the sample for the inventory was restricted to represent a portion of the total number of APDs, but has been improved by means of a stratified sampling protocol explained in Appendix 5. This method reduces the impact of potential inaccuracies introduced due to extrapolation of results to general areas. Some field offices had small populations of wells (<30), which can lead to relatively poor samples. In such cases, all wells in an office were sampled.

2.2 PROCEDURES FOR COLLECTING AND PREPARING OIL AND GAS RESOURCE, RESERVES GROWTH, AND RESERVES DATA

2.2.1 Undiscovered Oil and Gas Resources

2.2.1.1 Sources of Oil and Gas Resources Data

In conformance with 42 USC §6217, the volumes of undiscovered technically recoverable oil and gas resources in each oil and gas play are supplied exclusively by the USGS.

Editor's note–insert sidebar ("Oil and gas resources occur in four categories:") at this point

Undiscovered technically recoverable resources are those hydrocarbon resources that, on the basis of geologic information and theory, are estimated to exist outside of known producing fields. These resources can be produced using current technology without regard to economic profitability. Technically recoverable resources are a subset of the total resource-in-place that could be expected to be recovered over an exploration and development life cycle measured in decades.

The USGS assesses oil and gas resources in geologic "plays" or "assessment units." A play is a set of known or postulated oil and gas accumulations defined by common geological conditions (source rock, migration, timing, charge, traps, seals, etc.) that characterize a group of hydrocarbon accumulations in the subsurface. An assessment unit is defined as a mappable volume of rock within a total petroleum system that encompasses accumulations (discovered and undiscovered) that share similar geologic traits and socio-economic factors. Accumulations within an assessment unit should constitute a sufficiently homogeneous population such that the chosen methodology of resource assessment is applicable. A total petroleum system might equate to a single assessment unit. If necessary, a total petroleum system can be subdivided into two or more assessment units so that each unit is sufficiently homogeneous to assess individually.

The USGS assesses two resource play types: conventional and continuous. Conventional plays contain discrete hydrocarbon accumulations often associated with hydrocarbon/water contacts. Continuous plays are pervasive hydrocarbon accumulations that can cross rock unit boundaries, lack discrete structural boundaries, and exhibit other atypical reservoir properties (Figure 2-12). They include tight gas sands, gas shales, and coalbed natural gas (also referred to as coal gas, coalbed gas or coalbed methane). Compared to conventional plays, continuous accumulations typically are more geographically extensive. Most of the resources in the study areas in the lower-48 states are of the continuous type.

Figure 2-12. Conventional vs. Continuous Accumulations

The USGS has identified 150 discrete oil and natural gas resource plays in the Phase II study areas. The probabilistic mean estimate of hydrocarbon resource volumes for each USGS-defined play was utilized for this inventory (Table 2-4) The assessed resources include oil, natural gas liquids (NGLs), associated dissolved (AD) natural gas, non-associated natural gas (NAG) and liquids in gas reservoirs. Oil is a natural liquid of mostly hydrocarbon molecules. NGLs are liquid when produced to the surface but exist in the gas phase in the subsurface. Natural gas is a mixture of hydrocarbon gases consisting primarily of methane. Associated dissolved natural gas is that produced from oil fields, whereas non-associated natural gas is that produced from gas fields. The USGS assesses technically recoverable resources for each of these resource types, and these volumes were provided for the inventory. While modeled discretely in this analysis, for purposes of presentation in this inventory, undiscovered oil, NGLs, and liquids associated with natural gas reservoirs were subsequently aggregated into a single "Total Oil" resource category. Similarly, AD and non-associated natural gases were combined as "Total Natural Gas."

Table 2-4. Undiscovered Technically Recoverable Resources by Play

Table 2-4. Undiscovered Technically Recoverable Resources by Play (concluded)

2.2.1.2 Oil and Gas Resource Data Preparation

The geometry of an oil and gas play is defined by its geology and extends horizontally and vertically in the subsurface. Figure 2-13 is an idealized block diagram showing how three different plays can occur in a single area. Plays are commonly "stacked" in the subsurface so that a given surface land parcel can overlie numerous plays.

For this inventory, a homogeneous distribution of resource within a play boundary is assumed because of the lack of more geographically specific information. In fact, the USGS indicates that resources are generally not homogeneously distributed within a play. This is particularly true for conventional accumulations, and less so for continuous accumulations. Despite the assumption of homogeneous distribution of resources in the plays, various oil and gas densities can be mapped as a result of play stacking.

Figure 2-13. Conceptual Block Diagram of Oil and Gas Plays

2.2.1.3 Oil and Gas Resource Data-Related Caveats

The estimation of undiscovered technically recoverable resources is inherently uncertain, as reflected by the fact that the USGS develops cumulative probability distributions of the estimated resources for each play. These distributions are used to derive 95 percent probable resource (a 19-in-20 chance of that volume or more), 5 percent probable resource (a 1-in-20 chance of that much or more), and mean resource volumes. The mean volume, used in this inventory, represents the arithmetic average of all possible resource outcomes weighted by their probability of occurrence. The analytical results in the inventory use the mean and therefore do not explicitly reflect the range of uncertainty in the resource assessments.

Not all of the resource plays recognized by the USGS within the boundaries of this inventory have been evaluated. The USGS has identified hypothetical plays that lack sufficient data to estimate undiscovered resources. To the extent that hypothetical plays contain significant resources, the results presented here would be an underestimate.

It should be understood that all resource assessments change over time. Not only is it difficult to assess accurately the resource at any one point in time, but the recoverable portion of the resource changes in response to advances in technology, and changes in other conditions under which extraction occurs. Nonetheless, accurate and up-to-date assessments of the potential resources must be continually provided to ensure that public policy decisions are conducted with the best information possible.

For this inventory, the assumption is made that the estimated oil and gas volumes are evenly distributed under the surface area of each play. A resource density map for each basin was created in the GIS by using a spatial summation of the oil and gas volumes contributed by each play. The densities are expressed as millions of cubic feet (MMCF) of gas per square mile and thousands of barrels (Mbbls) of oil per square mile.

2.2.2 Proved Ultimate Recovery Growth (Reserves Growth)

The EIA's role in this inventory is to provide data and analysis relevant to proved reserves and reserves growth of crude oil, natural gas, and natural gas liquids that are associated with already discovered fields underlying Federal onshore lands. This responsibility involves:

- Providing estimates of proved reserves for these fields at the highest possible level of detail consistent with a legal requirement to protect the confidentiality of field operators' proprietary data.
- Estimating future ultimate recovery appreciation for currently producing fields.
- Providing inputs to estimate additional land access constraints that may result from expected ultimate recovery appreciation.

The estimation of proved reserves is necessary for developing reserves growth estimates.

The proved ultimate recovery (PUR) of an oil or gas field is the estimated volume of oil or gas that will ultimately be produced from the field. At any point in time, the PUR is the sum of a field's estimated proved reserves and its cumulative production. The estimated PUR for a new oil or gas field generally increases with time, as a result of new geologic and engineering knowledge gained during operation of the field.

This phenomenon is variously termed "reserves growth," "reserves appreciation," "ultimate recovery appreciation" or "proved ultimate recovery growth." Proved ultimate recovery growth (PURG), the term preferred by the EIA, has been recognized since 1960 and currently accounts for the majority of annual additions to domestic proved reserves. Owing to its importance to present and future domestic oil and gas supply, EIA has been highlighting PURG in the overview section of its annual reserves reports since 1992. Since 1976 PURG has grown in all but one year for both oil plus lease condensate and natural gas. From 1976 through 1994 only 12 percent of proved reserves additions of crude oil and lease condensate and 11 percent of proved reserve additions of wet natural gas were booked as new field discoveries. The rest came from the proved reserves categories related to the proved ultimate recovery appreciation process.[7]

The proved ultimate recovery for an individual field or group of fields in a basin "grows" with time due to such factors as:

- Delineation and development drilling that extends the area of known reservoirs
- Discovery of new producing zones (deeper or shallower)
- Application of improved reservoir management and well completion practices and technologies
- Economic factors that increase wellhead prices or reduce operating costs thus extending the economic life of producing fields.

Initial estimates of PUR are usually conservative owing to the small knowledge base available at that time regarding a field's performance. Annual estimates of a field's PUR normally increase significantly in the early post-discovery years as the field is delineated. In later years, PUR continues to grow due to such factors as installation of improved recovery technology, increased knowledge of field performance, and infill drilling, although generally the annual rate of growth slows. Consequently, the growth factors are large during the early years of field development and then often decline as PUR asymptotically approaches a maximum value, i.e., reserves growth usually slows as field development matures.

For the Phase II study areas, the EIA estimated remaining proved ultimate recovery growth (RPURG), the future reserves growth resource. The resources attributed to future reserves growth are 973 million barrels of oil and 10.55 TCF of gas. See Appendix 7 for a detailed explanation of the estimation methodology.

Table 2-5. Remaining Proved Ultimate Recovery Growth (Reserves Growth) by Study Area (Federal and nonfederal)

The EIA's selected RPURG estimates covering Federal and nonfederal lands are provided in Table 2-5. Not all of the Phase II study areas could be evaluated owing to insufficient data.

[7] Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2004 Annual Report, November 2005, available online at http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html.

2.2.2.1 Sources of Remaining Proved Ultimate Recovery Data

The EIA compiled the historical increase in estimates of PUR for oil and gas fields in each study area and extrapolated these data to estimate the PUR of the fields at abandonment. RPURG is the estimated future portion of the growth in PUR from 2003 to the time of field abandonment.

For each study area, the EIA created a database containing field names, field discovery dates, annual oil and gas production for each field, estimated cumulative production, and annual estimates of oil and gas proved reserves for each field.[8] Each field in a study area was assigned to a vintage year according to its date of first production or its date of discovery. The annual proved reserves estimates were usually available only from 1977 to present. The resulting files contained vintage year, number of fields in each vintage (in barrels of oil equivalent), PUR for each field vintage, annual natural gas PUR for each vintage, and annual liquid PUR for each vintage.

Many field names and codes had to be altered, corrected, and matched across the multiple data sources in order to accumulate properly the field data. Obvious major errors were corrected, but many apparent data discontinuities and variations within vintages were mostly accepted "as-is." Reserves data were used as reported by the field operators unless very obvious errors were found. Specific vintages that did not fit the trend of most of the data for a basin were excluded from the extrapolation. Attempts to divide the data within a basin into conventional reservoirs, tight formation, and coal gas resources were largely unsuccessful because of the limited number of vintages, the short histories available for some of the fields, and frequent inability to separate the data by reservoir type within a field.

The EIA used two models to estimate RPURG for each study area and resource type, an exponential cumulative growth factor model and a hyperbolic incremental growth factor model. The exponential model depends on annual average cumulative growth factors for a basin. The hyperbolic model depends on incremental growth factors by vintage, or age of the fields in the basin. Both are asymptotic functions that use time as the sole driver. Although other potential drivers such as drilling rates or wellhead prices are not directly used, these factors have affected the historical data that feed into the models. The application of both models for estimating PURG for a basin over time is described in Appendix 7.

Results of the two models were compared for each study area and hydrocarbon type and a preferred model result was selected based on the EIA modeling team's best judgment. The exponential model results were selected most of the time. Appendix 7 provides a detailed report of EIA's methodology and results.

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[8] Data sources included the EIA Reserves and Production Division's Oil and Gas Integrated Field File (RPD OGIFF), the EIA Field Code Master List (FCML), the EIA-23 Reserves Survey, various state web sites, and commercial sources (mainly IHS Energy Group).

There were insufficient data from the Appalachian Basin and Montana Thrust Belt for a PURG analysis. Separate estimates for tight reservoirs were not made for the Denver Basin, Black Warrior Basin and the Wyoming Thrust Belt owing to a combination of data anomalies and data interpretation concerns. In all study areas, the available coalbed natural gas data were deemed not to be dependable for establishing PURG and are therefore not separately reported. Tight formation results using the exponential model were reported for the Uinta-Piceance and Paradox/San Juan Basins, but were not carried forward into the analysis for the sake of consistency.

2.2.2.2 Remaining Proved Ultimate Recovery Data Preparation

The estimated remaining proved ultimate recovery or "reserves growth" resources for each study area were incorporated into the inventory by adding a "reserves growth resource" layer to the USGS undiscovered technically recoverable resources. As with the undiscovered resource layer, the inventory assumes that the reserves growth resources are homogeneously distributed within the geographic boundaries of the reserves growth resource layer. This is a simplifying assumption, which may be modified in the future as new reserves growth methodologies and findings become available.

The geographic boundary of the reserves growth resource layer was created for each study area from a union of the field boundaries of all the producing oil and gas fields identified by the EIA within the study area. The individual field boundaries were extended an additional mile in all directions prior to the union, so the geographic boundary of the reserves growth resource layer extends a mile beyond the 2003 boundaries of the actual fields incorporated into the layer. This was done to approximate future extensions to the proved area of producing fields, which contributes to reserves growth. Next, the total reserves growth resource estimated for each study area was homogenously distributed within the geographic boundary of the reserves growth resource layer for the study area. Lastly, the two resource layers, the USGS undiscovered technically recoverable resource layer and the EIA RPURG resource layer, were combined to create the oil and natural gas resource maps shown in Section 2.2.3.

2.2.2.3 Remaining Proved Ultimate Recovery Estimate Data-Related Caveats

The estimated reserves growth resources for the Phase II study areas are lower than generally would be expected, especially compared to previously published reserves growth estimates including the USGS 1995 National Assessment[9], the NPC[10], the Potential Gas Committee (PGC),[11] as well as some operators' not necessarily

[9] Root, D.H. and others, 1995, Estimates of inferred reserves for the 1995 USGS national oil and gas resource assessment, U.S. Geological Survey Open-File Report 95-75L.
[10] National Petroleum Council, 2003, *Balancing Natural Gas Policy-Fueling Demands of a Growing Economy*, September 2003. The Supply Task Group estimated reserves growth for natural gas.
[11] Potential Gas Committee, 2005, *Potential Supply of Natural Gas in the United States as of December 31, 2004*, September 2005. The PGC estimates "Probable Resources" for natural gas. PGC defines Probable Resources as

representative anecdotal reports of estimated reserves growth for fields in some study areas.[12] Appendix 7 (Table A7-2) contains a side-by-side comparison of this inventory's reserves growth estimates to other relevant estimates. Reserves growth in most of the study areas ranged from 3 percent to 25 percent of current proved reserves. However, the Black Warrior Basin reserves growth was estimated to be 110 percent of proved reserves.

It is unlikely that there is a single cause of the differences with other studies. Certainly there are some significant differences in methodology and input data. For example, the PGC uses a non-statistical, reservoir-specific approach that relies on expert judgment to estimate the probable resources associated with the additional development of an already discovered reservoir. Historically, the most successful estimates of reserves growth have relied on the use of reservoir level data, rather than the more aggregate field level data on which this inventory's estimates are based. This is not particularly surprising since most factors that affect the reserves growth phenomenon are reservoir-specific and will not necessarily apply to an entire field when it consists of multiple reservoirs as many fields do.[13] Unfortunately, reservoir level proved reserves data are only rarely available for onshore United States fields and the RPURG estimation must therefore be done using the field level data that are available. It should also be noted that this is, insofar as we know, the first time that field level RPURG analysis has been attempted on a scale comparable to that of this inventory.

The Energy Information Administration methodology used for the Phase II study areas and the methodology used by the U.S. Geological Survey to estimate reserves growth for the most recent National Assessment are both statistical extrapolations of historical reserves growth and are subject to the same inherent limitations,[14] although the methodologies differ in detail. These limitations introduce substantial uncertainty into the final results, which the USGS is currently addressing in an ongoing review of their reserves growth estimation methodology (see below). In a recent test, the USGS found that two different statistical extrapolation methodologies produce reserves growth estimates that differed by approximately 25 percent and were as much as 60 percent higher than actual volumetric data.[15] The results shown in Table A7-1 should be interpreted with these limitations in mind:

- Inherent uncertainty in the underlying data (for example, 'reserves' are defined differently by different operators and different commercial/private databases; fields and reservoirs are inconsistently defined).
- Current statistical methodologies rely on field age (since field discovery) as a surrogate for field development effort. Other factors such as reserves recognition

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resources associated with known fields including supply from future extensions of existing pools in known productive reservoirs, infill drilling, and future new pool discoveries within existing fields.

[12] For example, EnCana reports significant reserves growth in Jonah and Mamm Creek fields.

[13] *The Intricate Puzzle of Oil and Gas "Reserves Growth,"* available online at http://www.eia.doe.gov/pub/oil_gas/petroleum/feature_articles/1997/intricate_puzzle_reserves_growth/m07fa.pdf

[14] From Klett, Timothy, *One-Year Reserve-Growth Scoping Project, Fiscal Year 2006*, presentation to American Association of Petroleum Geologists, Committee on Resource Evaluation, February 9, 2006.

[15] Ibid; slide titled "Test of Modified Arrington and USGS Least Squares/Monotonic Methods"

practices, differential application of new technology and production monitoring practices, different operating environments, and access to markets may not be adequately represented by field age alone.

- Large fields have more weight in the analysis, which may bias the results toward the development histories of the largest fields in a basin or study area. Large fields may be more likely than smaller fields to receive consistently applied development efforts and new technology applications, and be less sensitive to economic factors.
- Uncertainties are not addressed directly, such as variance of the input data and uncertainties in the underlying assumed field development scenarios.

Table 2-6. Range of EIA Estimated Remaining Proved Ultimate Recovery Growth (“Reserves Growth”) for Selected Study Areas

Table 2-6, which shows the range of RPURG results using the two different models, exponential and hyperbolic, illustrates the uncertainty surrounding the reserves growth estimates. The model fits of the field growth factors (provided as figures in Appendix 7) appear to be very conservative in some cases and inconclusive in others, so that the resulting extrapolation of proved ultimate recovery may be too low. The datasets for some of the study areas may simply be too small to support adequately the extrapolation of remaining proved ultimate recovery. There are many apparent anomalies and errors in the available field-level proved reserves data series that doubtless affect the estimates and that, at present, would require a very labor-intensive effort to isolate, characterize, and correct.

A phenomenon observed in the 1995 USGS National Assessment may also be operating, in which the estimated reserves growth based on a dataset for the lower-48 states as a whole produced greater reserves growth estimates than the sum of reserves growth estimated independently for individual regions. In October 2005, the USGS commenced a one-year scoping project to evaluate possible improvements to existing reserves growth methodology, identify alternative methodologies, and recommend a robust reserves growth methodology that can be universally applied.[16] The EIA is investigating whether it might be possible to develop improved, less labor-intensive means of cleansing the field level data of its apparent anomalies and errors and whether the estimates can be improved by moving to a multi-parameter estimation methodology. The findings and recommendations of the USGS reserves growth scoping project will be incorporated into the reserves growth assessment for subsequent phases of this inventory. Consequently, the reserves growth volumes estimated for this report are likely to be re-evaluated and are subject to change.

2.2.3 Oil and Natural Gas Resource Maps

The products of the oil and gas resource data preparation work are maps of hydrocarbon volumes, projected to the surface. These maps depict areas of varying potential resource richness based on often overlapping play resource volumes. The distributions of undiscovered technically recoverable resources and reserves growth are

[16] Brenda S. Pierce, USGS, personal communication to Jeffrey Eppink, Advanced Resources International, regarding USGS Energy Resources Team Reserves Growth Scoping Project, project number 8930C1K.

shown by study area for oil in Figures 2-14 through 2-24 and for natural gas in Figures 2-25 through 2-35.

Figure 2-14. Total Oil Map, Northern Alaska Study Area

Figure 2-15. Total Oil Map, Uinta-Piceance Basin Study Area

Figure 2-16. Total Oil Map, Paradox/San Juan Basins Study Area

Figure 2-17. Total Oil Map, Montana Thrust Belt Study Area

Figure 2-18. Total Oil Map, Powder River Basin Study Area

Figure 2-19. Total Oil Map, Wyoming Thrust Belt Study Area

Figure 2-20. Total Oil Map, Greater Green River Basin Study Area

Figure 2-21. Total Oil Map, Denver Basin Study Area

Figure 2-22. Total Oil Map, Florida Peninsula Study Area

Figure 2-23. Total Oil Map, Black Warrior Basin Study Area

Figure 2-24. Total Oil Map, Appalachian Basin Study Area

Figure 2-25. Total Natural Gas Map, Northern Alaska Study Area

Figure 2-26. Total Natural Gas Map, Uinta-Piceance Basin Study Area

Figure 2-27. Total Natural Gas Map, Paradox/San Juan Basins Study Area

Figure 2-28. Total Natural Gas Map, Montana Thrust Belt Study Area

Figure 2-29. Total Natural Gas Map, Powder River Basin Study Area

Figure 2-30. Total Natural Gas Map, Wyoming Thrust Belt Study Area

Figure 2-31. Total Natural Gas Map, Greater Green River Basin Study Area

Figure 2-32. Total Natural Gas Map, Denver Basin Study Area

Figure 2-33. Total Natural Gas Map, Florida Peninsula Study Area

Figure 2-34. Total Natural Gas Map, Black Warrior Basin Study Area

Figure 2-35. Total Natural Gas Map, Appalachian Basin Study Area

2.2.4 Proved Reserves

Proved reserves are defined as quantities of crude oil, natural gas, or natural gas liquids that geological and engineering data demonstrate with reasonable certainty (defined as greater than 90 percent probability) to be recoverable from *known* reservoirs *under existing economic and operating conditions*. Proved reserves are, in effect, the current "inventory on-the-shelf" portion of total resource endowment.[17]

2.2.4.1 Sources of Proved Oil and Gas Reserves Data

[17] The full technical definition of proved reserves is at the Society of Petroleum Engineers website at http://www.spe.org/spe/jsp/basic/0,,1104_12169,00.html

Comprehensive estimates of the domestic proved reserves of crude oil, natural gas, and natural gas liquids are prepared annually by the EIA. These estimates are a combination of reported and statistically imputed volumes based on:

- Thousands of individual proved reserves and production estimates reported to EIA annually,[18] either at the field level or at the state level by a representative sample of the operators of domestic oil and gas wells. Of the 22,519 operators in the 2001 survey, 1,867 were included in the sample.
- All operators of active domestic natural gas processing plants who annually report their operations on Form EIA-64A "Annual Report of the Origin of Natural Gas Liquids Production." For the 2001 survey, 525 active gas processing plants responded to the survey.

Only the largest oil and gas well operators (those producing 1.5 million barrels or more of crude oil, or 15 billion cubic feet or more of natural gas per year) are required to submit to EIA proved reserves and production estimates by field for all of their operated properties. There were 172 large operators in the 2001 survey, all of which were included in the sample. The response rate was 100 percent.

Intermediate size operators (those producing less than the largest operators but at least 400,000 barrels of crude oil, or at least 2 billion cubic feet of natural gas per year) are required to submit production estimates by field for all of their operated properties, but are only required to submit proved reserves estimates by field when they maintain them in their records. There were 439 mid-sized operators in the 2001 survey. All were included in the sample and their response rate was also 100 percent.

Small operators are those with production less than 400,000 barrels of crude oil or 2 billion cubic feet of natural gas per year. There were 21,908 small operators in the 2001 survey. Of these, 1,175 were sampled with certainty at an associated response rate of 98 percent and an additional 622 were randomly sampled at an associated response rate of 95 percent.

2.2.4.2 Proved Oil and Gas Reserves Data Preparation

The procedures used to prepare the proved oil and gas reserves data are described in Appendix 8**.**

2.2.4.3 Proved Reserves Data-Related Caveats

Because the EIA's proved reserves survey is expressly designed to minimize the respondents' reporting burden and yet provide reliable estimates at the state and national level of data aggregation, the EIA does not have operator-submitted, field-specific proved reserves information covering every oil or gas field in the country. However, the EIA has data reported for about 90 percent of all estimated domestic

[18] Form EIA-23 "Annual Survey of Domestic Oil and Gas Reserves."

proved reserves. The EIA may have only partial reported estimates for a field that has two or more operators if one is not required to report proved reserves by field.

These deficiencies in EIA's field-specific proved reserves information were remedied for this inventory by use of additional procedures based on either publicly-available production data or reserve-to-production ratio analogs.

In addition to gaps and omissions in operator-reported estimates of proved reserves, the proved reserves data are subject to two further caveats:

1. For the EIA survey, field location is reported at the county level. The precise field locations needed for this inventory's GIS-based methodology required correlation of the EIA's reserves data files with commercial sources of field and/or well information that provide more precise location data. This process involved detailed, often well-by-well, work owing to the existence of non-standard field names and codes, or the occasional lack of a field name, in the commercial or State data sources.
2. EIA is obliged by law to ensure the confidentiality of the data submitted by each reserves survey respondent. Within the Phase II study areas, there are situations where a field is operated by a single operator, or where a single operator is dominant. In such cases, EIA cannot disclose the proved reserves estimates for the field without a written agreement from the operator waiving the right to confidentiality. Such agreements are rare and time-consuming to obtain. To avoid the release of confidential information while still adequately supporting this inventory, EIA elected not to present field-specific proved reserves estimates even where doing so would not have compromised a respondent's identity. Instead, the fields have been grouped into a range of proved reserves categories that are broad enough to prevent extraction of the estimates for any specific field.

Table 2-7 provides a summary of proved reserves on Federal and nonfederal lands. Note that proved oil and gas reserves are not presented on Figures 2-14 through 2-35. See Appendix 8 for a more detailed explanation of proved reserves estimation and field boundary construction.

Table 2-7. Proved Reserves Summary Statistics

This inventory is designed to portray the constraints on future access to the potential oil and gas resource base. Consequently, undiscovered technically recoverable resources and reserves growth resources are included in the categorization, but not proved reserves.[19] Table 2-8 summarizes the oil and gas resource types on Federal lands for each study area.

Table 2-8. Summary of All Federal Oil and Gas Resources

[19] Proved reserves were incorporated into the EPCA Phase I inventory. Due to the revision of inventory requirements by the Energy Policy Act of 2005, proved reserves volumes are reported in this Phase II inventory but are excluded from the access categorization.

by Study Area and Resource Type

2.3 DATA INTEGRATION AND SPATIAL ANALYSIS

2.3.1 Categorization of Oil and Gas Access Constraints

The main factors that affect access to oil and gas resources on Federal lands are land availability (Section 2.1.1) and leasing and drilling restrictions (Sections 2.1.2 and 2.1.3). To simplify the analysis and present meaningful results, these factors were categorized into a hierarchy that represents varying levels of access as shown in Table 2-8. This categorization was necessary to enable a reasonable quantitative analysis, given the fact that approximately 2,130 individual stipulations from 65 Federal land use plans (LUPs) exist for the study areas within the Phase II inventory.

Table 2-9. Federal Land Access Categorization Hierarchy

The hierarchy of categories was formulated to ensure that the constraints on oil and gas development could be appropriately assessed (especially for areas of multiple, overlapping stipulations), and to ensure that the cumulative impacts on access would be examined. In addition, the hierarchy was formulated based upon the accessibility of the lands for leasing, and for areas where leasing is permitted, the impacts relative to the difficulty for conducting drilling operations.

The Federal lands categorization hierarchy is ordered from “No Leasing” (most constrained) to “Leasing with Standard Lease Terms” (least constrained) as follows:

1. **No Leasing (Statutory/Executive Order) (NLS)** are lands that cannot be leased due to Congressional or Presidential action. Examples include national parks, national monuments, and wilderness areas.
2. **No Leasing (Administrative) (NLA)** are lands that are withheld from leasing based on discretionary decisions made by the Federal land management agency. NLA areas can include endangered species habitat and historical sites.
3. **No Leasing (Administrative), Pending Land Use Planning or NEPA Compliance (NLA/LUP)** are lands that have not yet undergone or are currently undergoing land use planning or NEPA analysis, and that are generally not available for leasing. In the cases where there is no land use plan in effect, non-Federal mineral estate underlying Federal land is categorized as NLA/LUP to reflect the fact that access to mineral estate can be allowed through the NEPA process.
4. **Leasing, No Surface Occupancy (NSO) (Net NSO for Oil & Gas Resources)** are lands that can be leased but ground-disturbing oil and natural gas exploration and development activities are prohibited. These stipulations protect identified resources such as special status plant species habitat. Their surface areas are mapped as described by the land use plans. However, at least some of the resources can be accessed by directional drilling from nearby lands where surface occupancy is allowed. This is accounted for by creating an extended drilling zone (EDZ, as described in Appendix 9) that reduces the size of the NSO

area. The area removed is then placed in the next most restrictive resource access category (5 through 9, below) that would otherwise apply in the absence of the NSO stipulation. Within the EDZ area the underlying resource is considered accessible even though the surface above it cannot be occupied by drilling equipment. After the EDZ is removed, the NSO area that remains is referred to as “Net NSO” (NNSO) and the resources under it are therefore considered inaccessible.

5. **Leasing, Cumulative Timing Limitations (TLs) on drilling of >9 Months**
6. **Leasing, Cumulative Timing Limitations (TLs) on drilling of >6 to ≤9 Months**
7. **Leasing, Cumulative Timing Limitations (TLs) on drilling of >3 to ≤6 Months** are lands that can be leased, but stipulations and/or COAs limit the time of the year when oil and gas exploration and drilling can take place. Timing limitation stipulations prohibit surface use during specified time intervals to protect identified resources such as sage grouse habitat or elk calving areas.
8. **Leasing, Controlled Surface Use (CSU)** are lands where stipulations and/or COAs control the surface location of natural gas and oil exploration and development activities by excluding them from portions of the lease. For example, a CSU stipulation could require an operator to develop a specialized mitigation plan based on the presence of moderately steep slopes. This category also includes the minimal areas that have timing limitations of less than three months.
9. **Leasing, Standard Lease Terms (SLTs)** areas are lands that can be leased and where no additional stipulations are added to the standard lease form. Standard lease terms, however, still dictate that the lessee must comply with many environmental standards and other requirements (see 2.1.2, above).

Categorizations were made on the basis of LUPs and discussions with Federal land management agencies. In most cases categorization is relatively straightforward; in other cases judgments were made based upon experience with stipulation datasets. For USDA-FS, FPs standards and guidelines are both included in the definition of "Management Direction" at 36 CFR 219.3 (Forest Planning), and were used synonymously without distinction in evaluating USDA-FS stipulations.

All categorizations were made available to field offices for review and comment.

2.3.1.1 Data Integration And Spatial Analysis-Related Caveats

The following precautions are advised when reviewing this study:

- A total of 2,132 stipulations in 65 LUPs were analyzed in the Phase II inventory. Substantial efforts were made to assess stipulations where no GIS data were available, either by digitizing or obtaining data from other sources. Despite these efforts, not all stipulations have corresponding GIS data. While it is impossible to assess the absolute magnitude of this issue, it is nevertheless believed to be significant. By item count, approximately 39 percent of total stipulations in the Phase II inventory do not have GIS associated with them. To the extent that this issue exists, the inventory overestimates access to lands and resources. The induced error is likely to be less than 39 percent as many of the missing stipulations are not likely to have large geographic coverage or may be outside a given study area. This issue points to a data gap to be addressed by Federal agencies.

- In NSO areas that abut non-Federal lands, no assumption was made about the availability of adjacent non-Federal lands as a base from which to drill under Federal lands. It is estimated that this situation has a minimal effect, impacting less than one half of one percent of resources in the study areas. Therefore, an Extended Drilling Zone (EDZ) was not applied to NSO lands adjacent to non-Federal lands.

2.3.2 Analytical Modeling of Federal Lands and Resources

See Appendix 9 for a detailed description of the GIS methodology used to categorize the Federal lands and resources for the inventory.